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Most importantly, we would like to express deep appreciation to all the authors who contributed to these proceedings. Our appreciation for their efforts will be shared by the thousands who will read and utilize the information contained in these proceedings.

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PREFACE

The year 1983 marks the 10th annual Energy Technology Conference and the 10th anniversary of the OPEC oil embargo. During this decade energy matters have dominated national and international affairs and the dramatic changes in energy prices have had repercussions throughout the national and international economies. The cycle of annual energy growth has been broken with more efficient use of energy causing annual declines.

During the last year the world energy market has seen a dramatic decline in the price of oil. With the OPEC share of world oil production continuing to decline, the price setting power of the OPEC cartel has declined significantly. Here in the United States the federal government has settled in for a low profile energy policy. Although the administration's original plan to abolish the Department of Energy has lost its momentum, the Department of Energy has lost the limelight in Washington.

This 10th Energy Technology Conference again shows that the private sector is responding responsibly to the imbedded energy problems. Most of the 147 papers presented herein report on work in the private sector. Again this year, the relative amount of papers dealing with efficient use and management of energy has increased.

All associated with the 10th Energy Technology Conference—sponsors, speakers and attendees—should take pride in the dramatic accomplishments that have been made since 1973. Through the efforts of the energy technology community, public and private, our society has significantly increased the diversity of energy supplies and has improved the productivity of energy uses for a more stable energy future. .

Herein we present the results of a successful conference.

Richard F. Hill
Editor

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INVOCATION

Let us pray. . .

Almighty God, you are the source of all life, all knowledge, all power. We are your children, but in your love you have also commissioned us to be stewards-partners with you in the work of your kingdom. We thank you for this dignity and ask your help in meeting our responsibilities to you and your people.

Bless us as we gather for the Tenth Energy Technology Conference and Exposition. May we who participate grow in the breadth of our knowledge and the depth of our commitment to our professions. We come from many different specialties with different points of view. Bestow on us a spirit of openness and unity. May our competition be wholesome and our cooperation fruitful. Give us humility, that we may recognize we are servants; yet, also grant us joy and pride in our work, and the creativity that comes from trust in you.

Lord, those gathered here will help shape the future of the world and the lives of its people. May we seriously and generously accept our responsibilities. Yet also grant us the perspective that comes from realizing that all things shall pass. Expand our vision to embrace eternity and so teach us the true value of things.

May we work and build according to your will; so that, when an accounting of our stewardship is demanded, you might welcome us into your kingdom where you live and reign for ever and ever. Amen.

Father Joseph Rautenberg
Archdiocese of Indianapolis

CONFERENCE OPENING

Energy Lessons from the Past Decade
1974 - 1983

Welcome . . .

It is most appropriate to briefly reflect on the first ten years of service to the energy community by the Energy Technology Conference (ETC) on this, the tenth anniversary of ETC.

Looking back over the past ten years since the conference was initiated, I see many positive accomplishments by the Energy Technology Community. To name a few:

First, the evolution of a national awareness that energy is finite and expensive.

Second, the development of a wide range of new products and services for the energy market, as reflected in the ETC Exposition. This 10th Exposition is the first energy international trade fair certified by the U.S. Department of Commerce. It is interesting to note that at ET-1, we did not have an exhibit because there wasn't much to exhibit ten years ago.

Third, the creation of an energy constituency in industry and government that will ensure that our country and the world better plan our energy future.

As for the next decade, two key lessons are evident; One lesson that we all should have learned from the past decade is that the business of energy is dominated by change . . and this change is rapid and dramatic. Lack of clarity about the future has been one of the most compelling lessons of the past decade. This change must be factored into all future energy planning. We no longer have the luxury of stability that was characteristic of earlier energy planning. Utilities, government and others in the energy community, of necessity, must develop alternative planning that will include a large degree of flexibility.

A second major lesson is that we—the energy technology community—will be challenged by technology transfer. I am appalled at the myopia of so many in the technology community who are not able to see that the ultimate goal of technology is to benefit society. Too many scientists and engineers are doing research just for the sake of research and have disdain for the ultimate goal of utilization, viewing that as the exclusive domain of salesmen. If Edison had a similar attitude we would all be sitting in the dark. If this negative attitude continues, the public is going to eliminate us by forcing discontinuance of the funding for energy technology support.

Everyone in energy technology must give technology transfer high priority or we will see scientific and engineering organizations fade away. We must show the public, the regulators and the energy users the benefits from energy technology expenditures to justify our own continued existence.

I look forward with hope to an increase in technology transfer and to aggressive marketing for energy technologies, with the ultimate result being prosperity for everyone in this next decade of service by the Energy Technology Conference.

Thomas F. P. Sullivan
President
Energy Technology Conference

Part I

POLICY

The world is again feeling the trauma of a dramatic change in global energy crisis—only this time it is the significant decrease in the price of oil. With the first decline in OPEC oil prices in ten years, nations and major companies are reassessing their energy policies.

The utilization of various individual energy forms is controlled by available technology and engineering economics and also by government regulations and selective government financial support. Government policies determine the degree of control and support within which industry must operate.

The following key papers present national and global energy policies.

THE ENERGY DECADE: LESSONS FOR TOMORROW

Mr. Floyd L. Culler, Jr.
Electric Power Research Institute
Palo Alto, California

Thank you, Mr. Chairman. It is an honor to open the 10th Energy Technology Conference and Exposition for 1983.

This year also marks the 10th anniversary of the Electric Power Research Institute. Certainly more important to the world energy scene--1983 is the 10th anniversary of one of the most far-reaching events of the latter half of this century: the OPEC oil embargo which began in late 1973.

Because of these coincident anniversaries, the time seems appropriate to step back from the year-to-year reports on the state of energy; and, instead, review and assess the developments of the past 10 years.

Early in the decade, a widely-held view maintained that the world was on the brink of a crippling depletion of its energy resources, a view that brought forth the call for basic and precipitous changes in our energy use and way of life. In light of the current worldwide oil surplus and the prospect for sustained, adequate supplies of fossil fuels, that view was obviously exaggerated. But equally incorrect is the currently developing attitude which argues that we have solved our energy problems. The experience of the past 10 years has taught us that we are not about to plunge into a world short of energy resources--even oil. We learned that there is much to be gained by using energy efficiently, and that conservation measures have broad economic and social justification. But we clearly have **not** resolved our energy problems, nor have we been able to set a clear new long-term course for prudent energy use.

Also, in early 1973, there was a compelling concern about the effects of energy production and use on the environment and human health. Added to this were serious questions about the social value and necessity of economic growth, and there were popular recommendations for "a system of constraints on the production and consumption of energy." The Club of Rome predicted, in The Limits to Growth, a "collapse" of the "world system" if growth--and energy use--continued its rapid increase. Many economists thought that oil and gas were underpriced, particularly in the United States. Some recommended increased prices to force conservation.

At the same time, energy analysts assumed that a robust economy would continue to grow at rates experienced during most of the postwar period. All-out expansion was predicted for each energy supply sector. These opposing views provided the basis for a continuing debate about energy policy.

Americans were jarred by the oil embargo and the emergence of OPEC. The price of oil quadrupled from about $2.50 to more than $11 a barrel, at a time when we were importing about 45 percent of our domestic consumption. Arab members cut back oil production by an amount equal to about 10 percent of the world's supply. The price rise that was proposed by economists as a conservation measure was, therefore, accomplished without internal political action.

The idea that the world would quickly run out of readily available fossil fuels was reinforced by a temporary natural gas shortage, interruption of coal supplies caused by a strike, and an extraordinary winter freeze that turned many above-ground coal piles into icy blocks. Perhaps the most serious economic blow came in 1979 with the doubling of world oil prices to about $28 a barrel. In ensuing years, the price of oil reached about $35 a barrel and $40 on the spot market, before beginning to decline this year.

Behind the headlines and worry of shortages, the energy situation was dominated by one overriding problem: the adjustment of the world's economy to the very rapidly occurring distortions caused by the new oil prices. Those adjustments have been exceedingly difficult both because of the very high prices, and the speed with which vexing and sometimes impossible adjustments had to be made.

One very beneficial effect of high oil prices and price decontrol is that it made it possible to develop large new sources, which previously would not have been looked for or brought into production.

The fluctuating economy during the decade was continually disturbed and depressed by the tenfold increase in the price of oil, and the consequent massive transfers of wealth from consuming to producing nations.

The tenfold increase in oil prices severely constrained the U.S. economy and that of every other nation. The direct cost alone has been astounding: since 1973, we have sent more than $450 billion to other countries in exchange for oil; and we are continuing to export more than $1 billion a week. A study, sponsored several years ago by the Institute for Gas Technology, indicated that the combined direct and indirect costs of a barrel of imported oil might be as much as $80 in the United States' economy. With only small delays in time, proportionate increases in the prices of other fuel resources occurred.

Currently, we are learning that the indirect costs of our energy "price adjustment" are larger than the dollars themselves. The U.S. gross national product has fallen several times since the Great Depression: in 1974-75, after the first round of oil price increases; in 1980, after the second; and now in this longest of postwar recessions. The International Energy Agency estimates that the total cost of the 1979 price increases to its member countries alone amounted to more than one $1 trillion in two years. Rather than an invisible lubricant for our economy, oil became--because of price escalation--a spur to inflation which accelerated the current imminent sharp downturn in our economy.

We now have high unemployment and low economic productivity. We are experiencing losses that may be occurring in our basic industrial structure, because we are not competitive in may areas where we formerly were leaders. Obviously, all of the industrial sectors woes are not a result of energy price rises. Lack of capital investment in new processes and techniques has made it difficult for us to compete with industrial societies which have tooled up since World War II.

Because of its contributory effect to economic destabilization and higher prices, energy production and use has become, and remains, an important political force at federal and state levels. This politicalization has significantly increased the uncertainty surrounding future policy options. It is not clear how policies, stable enough to plan for energy actions, can emerge from the political uncertainty which now exists. Energy policies which should remain reasonably unchanged for many years are being set by the controlling federal and state agencies for the short-term, many inconsistent with actions previously taken. For the energy industry, where decisions require 10 years to implement, and where new technology requires 20 years or more to deploy at high risk, short-term policies are not enough.

Concern about environmental pollution and protection of human health from industrial pollutants was well advanced in 1973, as the decade of energy uncertainty started. The resulting regulations--some necessary, some exaggerated and some poorly defined and executed--raised the cost of energy and further politicized the energy sector. The escalating price tags for environmental protection increased capital and operating costs, as well as lengthened the time required to place new plants into production. For the regulated utility industry, this double whammy of significantly higher capital requirements, and longer periods required to derive income from invested capital, added to the rapidly increasing fuel costs. Uncertainties in the process and substance of regulations remain major destabilizing factors in future energy production.

As we enter the second energy decade, energy policy is still characterized by uncertainty. But there are positive signs for adequate future supply price stabilization, or even reductions favorable for the long-term economic health of the nation. We know much more about using energy efficiently and practicing conservation. This hard-learned knowledge will serve us well, as we try to restructure our economy. We know what to expect of government in the policy areas, and I hope we will make appropriate adjustments.

In 1982, because of the decontrol of oil prices, oil production in the lower 48 states increased for the first time in a decade. The source of our imported oil has also shifted dramatically: in 1979, 66% of our imported oil came from OPEC; and more than 1/3 from its Arab members. Today, only 44% comes from OPEC and only 19% from Arab states. Oil prices are now dropping, perhaps, seeking a new and lower level. Some predictions say $20, others $25 per barrel. New oil suppliers (Mexico, Nigeria, Venezuela, and others) are now harshly affected by dropping oil prices and need assistance to recover. At the same time, the rest of the world benefits, of course, from lower fuel costs.

The outlook for natural gas has improved substantially. Domestic gas reserves seem sufficient to supply demand for 20 to 30 years and more. Mexico and Canada have surpluses of gas. Complete deregulation of gas prices represents another major adjustment that the U.S. economy appears ready to make. Hopefully, actions now pending will end major energy price distortions and make decisions concerning gas use more rational.

Coal remains our greatest domestic fuel resource and the most under-utilized. Since 1973, coal use has increased slowly, expressed by increases in coal consumption or electricity generation; and there has been a steady increase in exports. Conversion to coal in the electric utilities has slowed, however, because of the decrease in electricity demand--mainly in the industrial sector during the past year. Despite coal's potential as a fuel, its short-term outlook remains uncertain, dependent upon electricity demand which in turn is dependent upon economic recovery. Because of the recession, coal production this year is expected to be only marginally higher than in 1980.

Over the past decade, as during the last 50 years, demand for electric power has followed GNP closely. While industrial, commercial, and residential consumers have cut back on their use of every other form of energy since 1973, they have steadily used proportionately greater amounts of electricity. Only 8 percent of America's households were heated by electricity a decade ago. Since then, more than half of all the new homes built have been electrically heated. Heavy industry is steadily moving to electric arc furnaces; electric induction heating of metals; and increased use of lasers, ultraviolet lights, computers and robotics--all of which require electricity.

This long-term pattern of the electrification of industry was interrupted in 1982 by the sharp downturn of demand in the industrial sector, particularly in the industrial heartland of the U.S. As the economy recovers, the industrial load will return slowly. Electricity is generated less from oil where the cutback is about one third. Natural gas and hydro capacity have remained essentially unchanged as contributors to electricity supply. The replacement energy forms have been coal, which now produces more than half of all our electric power; and nuclear energy, which has tripled since 1973.

Our studies at EPRI indicate that the electrification of our economy should accelerate, over the next several decades, as the economy recovers and begins to grow again. The basic need to compete with other nations in the marketplace; revitalization of our basic industries; and the expansion of our electronic, informational, and other "sunrise" industries will use more electrical power. We estimate that electricity will increase as a percentage of total U.S. energy consumption from 40 percent today, to upwards of 50 percent by the year 2000.

Historically, electricity consumption has paralleled the pattern of economic growth. While over the past decade, the historic linkage between economic growth and the growth of overall energy use has been broken, the link between the economy and electric power demand has remained coupled. For more than three decades now--through economic prosperity, energy crises, war, inflation, and the current recession--essentially every advance in our GNP has been accompanied by an increase in the use of electricity. The specific ratio has dropped currently; and it may continue to change, but studies indicate that our economy is not likely to grow at a rate much faster than our use of electric power.

More electrical power will be consumed as industry recovers, because it can be more precisely controlled. It can be delivered in many forms in carefully measured quantities. It is the motive force to move robots and power electronic controls. It can be used to improve the economic efficiency of industrial heating in industries where large quantities of heat are requried. And, with efficient heat pumps to raise temperatures, it allows reuse of low-temperature heat.

Nuclear energy accounted for less than 4 percent of our electric power in 1973; this year, its share will most likely top 12 percent. Nuclear power is currently plagued by high front-end costs and licensing uncertainties. However, it is moving into second place behind coal as a source of electricity. It will continue to grow throughout the 1980's, rising to about 20 percent of our total electric supply early in the next decade, as reactors now under contruction are completed. Nuclear fuel remains one of the world's most abundant energy sources; and with the necessary emergence of the breeder, at the turn of the century, will provide an energy source for 5000 years and longer.

Our decreased use of oil has distracted us from demonstrating synthetic production of gaseous and liquid fuels from coal and shale. The international competition for the world's finite supply of oil remains a long-term problem and a short-term threat. The full-scale demonstration of liquefaction processes from coal has not yet occurred, but pilot plants of significant scale have operated successfully for a short time. Because of a change in basic policy by the Department of Energy to discontinue support of commercial-scale demonstrations, the EXXON Donor Solvent Process and the H-Coal Process operated briefly; and were closed down without fully accomplishing their initial purposes. Exploration of the two-stage hydrogenation of coal, as represented by the Solvent Refined Coal Process, will continue to be explored at a small test facility. The Sasol Plant expansion, using a modernized and successful Fisher Tropsch process in South Africa, is proceeding. The future of shale conversion demonstrations, however, is uncertain.

The gasification of coal, both to methane and to medium BTU gas is proceeding at full demonstration scale. The medium BTU, combined-cycle demonstration for electricity generation at the Cool Water Station of Southern California Edison is well along in construction, supported by a major consortia of private companies. The Plains coal-to-methane gasification plant is proceeding. There are basic, measured accomplishments resulting from a decade of work in synthetic fuels.

The use of solar heat in space heating and for hot water heaters for homes and businesses has been shown to be practical and economic in many regions of the U.S. Generation of electricity from the collection and concentration of solar radiation has proven to be possible, but still too expensive for widespread use. This is particularly true for the Rankine and Brayton cycles. There is progress in solar photovoltaics and solar photo thermoelectric systems, especially in amphorous photoelectric materials. The development of wind machines is well advanced. One more set of design changes for the existing machines should make them reliable enough to be deployed in areas where there is sufficient wind.

A 50 MW geothermal demonstration plant is to be built at the Heber Field in Southen California using hot water, rather than steam. Geothermal energy derived from hot water is reaching the state of demonstration, where routine use is likely in appropriate regions where there is adequate supply. Geothermal steam is being used increasingly in California as a regular supplement to centrally generated power from fossil fuels and uranium. In December of last year, the successful first firing of the Tokamak Fusion Test Reactor added to the growing confidence that the scientific feasibility of fusion will be demonstrated soon. The engineering and economic feasibility of fusion should steadily emerge through a series of test machines, some differing in approach and principle from the noncontinuous Tokamak, to be built over the next 20 years.

Energy production and use is dominated by basically political views. Establishing long-term energy policy will be difficult because of frequent changes brought about by changes in political leadership. The existence of three differently constituted major energy agencies in 10 years, and a proposition for the dissolution of DOE certainly support the view that stable energy policy cannot be anticipated on a federal level.

The concern for the environment and protection of human health is deeply ingrained and will remain as factors in energy planning. But, environmental objectives can be met by making changes at a pace that is not economically ruinous, if prudence and patience combine to make sound policy.

The processes of regulation and their administration need change. Usually, it is possible to set appropriate standards and estimate risks through scientific evaluation. The adversarial nature of the processes by which regulations are administered, however, causes long delays and high costs. The pervasiveness of regulations and the uncertainty of timing bring a dulling influence to innovation. Our research and development has slowly been diverted from creative to defensive endeavors. New and exciting ideas are not emerging rapidly from industrial research in the United States. Creativity has been blunted by the unnecessarily burdensome nature of our regulatory practice. The fear of opening up reviews of existing practice stops the advent of desirable improvements.

We can look forward to a future which will have fewer constraints than were evident in the last decade. It now appears that there are ways to resolve some of the troublesome problems which appeared in the 1970's. Prices of oil seem to be leveling. Many of the costs of environmental protection have been internalized, although many remain. In nuclear power, the Waste Disposal Management Bill, and the rapid movement toward its implementation, promise to reduce public concern. So does the possibility of reducing the design basis source term, which now seems justified by current knowledge of the performance of iodine, in the event of a major accident. There may be a safety margin large enough in the current source term to permit enough of a decrease to eliminate all near-term deaths, and a significant reduction in genetic effects.

New technology for treating and burning coal--gasifiers, combined cycle, fluidized beds, and controlled temperature combustion--will provide electric utilities with generating systems which are clean and safe, when old systems are retired and new capacity is added.

Most importantly, however, there are signs that the revitalization of the heavy industrial sector in the United States may be starting.

New technology and processes, each more energy efficient than their predecessors, are available for the production of steel, nonferrous metals, ceramics, glass, chemicals, and paper. Because of the cost of the energy component of basic production processes, there is an opportunity for energy suppiers to work cooperatively with their major industrial customers to achieve energy and economic efficiency. Although this opportunity exists, particularly for electricity, it applies most certainly to other energy forms as well. It is possible that energy producers can speed recovery by acting to catalyze our industrial rejuvenation.

Thus, I am more confident about our energy future, as we enter this decade, than I was in 1973. As we have done in previous times of difficulty, we will turn to new industrial technology to restore our economy and to rejuvenate the energy industry which makes it run.

* * *

PRIVATE SECTOR INITIATIVES IN ENERGY CONSERVATION

Arnold F. Rebholz
The Prudential Insurance Company of America
Newark, New Jersey

I would like to start with a quote from Peter Drucker's book, Managing for Results. Drucker says, "It is always futile to restore normality since normality is only the reality of yesterday. Our job is not to impose yesterday's normal on a changed today; but to change the business, its behavior, its attitudes, its expectations - as well as its products, its markets and its distributive channels - to fit the new realities."

The quote surely applies to the subject of energy and to this conference, and also with the substance of my remarks today concerning The Private Sector's Initiatives in Energy Conservation. Whatever we considered normal in the past no longer applies. We must seek the means to implement those practices which will result in conserving existing energy sources while seeking alternate sources.

Prior to the Arab oil embargo of 1973 the availability and the cost of energy was not a major factor being considered by the real estate industry. After the 1973 oil embargo it became a very real consideration as it affected investment decisions as to:

(1) The type of real estate purchased - mortgaged or sold
(2) The location of real estate investment
(3) The establishment of construction criteria
(4) Management decisions relating to existing real estate investment.

At Prudential we took steps to establish an energy management program that would meet three primary objectives:

(1) To reduce energy consumption in all our properties by 50%.
(2) To meet the GSA standard of not more than 55,000 BTU's per square foot in all new construction.
(3) To seek new or alternate energy sources and/or to find construction techniques to substantially reduce consumption below GSA standards.

Our Energy Management Program was designed to address both Phase I practices, covering items of a nontechnical nature to Phase II practices dealing with technical equipment and services. Some of t specific Phase I practices implemented included:

(1) Establishing specific hours of operation in a property as leases permitted.
(2) Maintaining temperatures at prescribed levels (68° in winter, 75° in summer).
(3) Reduce lighting standards.
(4) Strengthening of expense escalations in leases.

Some of the Phase II practices implemented include:

(1) Upgrading inefficient HVAC systems
(2) Installing timing switches
(3) Installing energy management computers to control lighting, motors, HVAC systems
(4) Applying solar film to windows
(5) Separate metering utilities.

While implementation of these kind of practices has achieved the intended objectives, a means of insuring that no property is allowed to regress to previous consumption levels is imperative. In responding to this need, Prudential employed Natkin Energy Management of Englewood, Colorado, to implement and to monitor an energy consumption tracking system for all properties in the Prudential portfolio. Natkin Energy Management had developed such a program and labeled it their PACE program (Periodic Audit for the Conservation of Energy). The PACE program is designed to measure monthly the consumption and cost of energy used for each building. The energy actually consumed is compared against data that has been normalized for each property as to location, building type and expected energy consumption levels. The PACE program provides on-going monitoring of each property since it requires the monthly input of energy consumed and provides a monthly computerized analysis.

Information advising that a property is using in excess of n energy consumption as established for that property provides a bas for action toward energy reduction. Such information leads to the following actions:

(1) Performance of specific building energy audit to determine cause of excess energy use.
(2) Analysis of corrective action for cost/benefit analysis.
(3) Recommendation for corrective action.

As properties are acquired or developed, they are added to the PACE program to insure our on-going monitoring of each property in our portfolio.

Prudential's extensive property development operation requires our being sensitive to state of the art technology with constant evaluation as to economic impact in building energy-conserving features into new construction. Each new development is reviewed carefully by staff architects and engineers to insure our meeting energy consumption standards and objectives.

Prudential's third objective in our energy management program is to seek new or alternative sources of energy and/or to find new construction techniques that would substantially reduce energy consumption.

This has been addressed in a rather ambitious pilot program located at Princeton University's Forrestal Center where two buildings of 130,000 square feet each are being completed. This program has demonstrated the successful merger of private, academic and government sector efforts toward a common goal.

This program first involved Princeton University's Center for Energy and Environmental Studies, who initiated studies, funded by Prudential, on the use of ice ponds for the cooling of large commercial buildings. The program was then extended to Princeton University Architectural School who collaborated with Skidmore Owings and Merrill, Flack and Kurtz Engineering and Princeton University's School of Engineering in studying and designing a building product that would incorporate many energy-saving techniques. The government sector, through the work of the Department of Energy, has now been added to this project through their participation of a tracking and monitoring system that will provide knowledge to be disseminated to the general public.

It is anticipated that this program will demonstrate the practicality of developing a commercial product that can address specific energy conserving techniques while remaining economically competitive and esthetically pleasing to the user market as well as to the community in which it exists.

It is assumed also that many features of this product will be successfully transferred to future construction in responding to the need to conserve energy.

I will conclude by expressing our belief that it is, as Peter Drucker states, the responsibility of the private sector, the academic sector and the government sector, to change the behavior, the attitude and expectations of people towards energy conservation by being a part of changing the product, the market and the way we manage energy.

UNION OIL'S VIEW OF ENERGY PROGRESS

FRED L. HARTLEY
CHAIRMAN AND PRESIDENT
UNION OIL COMPANY OF CALIFORNIA

It's a great pleasure to be a part of this 10th anniversary Energy Technology Conference. The subjects covered in the papers and the exhibits unquestionably offer the best education on energy available anywhere in the world today. I should add that it's indeed fortunate that you have chosen Washington, D.C. as the conference site--for nowhere else in America is there still so much need for energy education.

This 10th anniversary conference nearly coincides with the 10th anniversary of the oil industry's most extraordinary event--the Arab oil embargo of 1973. The changes set in motion by that event have profoundly affected every aspect of the energy spectrum. In the past 10 years we've learned, among other things, about the shocks--political and economic--that shortages and a four-fold price increase can create, about the need for an enormous variety of new energy technology, and about America's capacity to learn to use energy efficiently. Ten years ago these subjects were only discussed in theoretical terms, if at all. But now they are a vivid--at times, all too vivid--part of our recent personal experiences.

Today I'd like to draw on these experiences to offer some overview comments on the nature of America's recent energy progress. I will also offer a few thoughts on the progress--and the problems--that still lie before us.

Looking back over this past decade, it's obvious that America has, indeed, made enormous energy progress. Problems remain, as always, but clearly we've come a long way.

At the top of the list, I put energy conservation. I find it quite amazing how well America's energy consumers--whether individuals or industries--have quickly learned the absolute importance of energy prudence. Put another way, they are proving again the principle that a barrel saved is as good as a barrel produced and the saved barrel does not have to be replaced by repetitive exploration and production. A measure of this progress can be seen in the fact that America's economy can now achieve a unit of real growth by using <u>less than half</u> as much energy as it required a decade ago--probably one of the most remarkable structural changes in the history of our nation's economy.

Union Oil is, of course, doing its share in energy conservation. For example, waste heat from one of our coke calciners will soon be used to power a turbine producing 27,000 kilowatts of electricity. This power, which will be sold to a local utility, will meet the yearly electrical needs of some 27,000 people.

In our day-to-day operations, we have taken hundreds of small steps that have, over the years, added up to impressive savings. Examples here include re-lamping our head office with energy-efficient bulbs, substituting smaller air conditioners for oversized chillers, and switching our building cleaning schedule from night to day. We estimate that these and other conservation moves have saved at least four billion kilowatt hours of electricity over the past 10 years.

Second on my list of America's progress, I place the enormous collection of new technology that is now emerging to help America find, produce, and use its future energy more economically and more efficiently. The papers listed in the conference program and the exhibits on display give ample evidence of the breadth of this progress. In a sense, we are seeing a replay of America's innovative genius that carried the day in World War II and took us to the moon in the 1960's.

Turning to Union Oil's efforts in technological innovation, I could, for example, cite a series of developments in new exploration technologies, in deep water platform design, in enhanced oil recovery processes, or in hydrocracking refining technology. But rather than concentrate on improvements to known technology, I'd like to spend a few minutes describing Union Oil's progress in developing two of America's alternative energy sources--geothermal energy and oil from oil shale.

Over the last 20 years Union Oil has been the pioneer in developing the totally new technology needed to find, drill, control, and produce geothermal energy. We are now the world's largest producer of geothermal energy, providing the steam to power more than 1.5 million kilowatts of installed generating capacity here and abroad. Our largest single project--indeed the world's largest--is at The Geysers in northern California, where we produce and sell dry steam to a local public utility. This steam is used to produce electricity equal to the needs of the city of San Francisco. In the Philippines, we produce hot water which is flashed to steam and then converted to electricity.

A few weeks ago, we dedicated our second 10,000 kilowatt demonstration geothermal plant in California's Imperial Valley. When we drilled our first experimental wells in this area some twenty years ago, we discovered large quantities of geothermal energy. Unfortunately, it was contained in corrosive, fast-scaling brines that are up to ten times as salty as sea water.

With time, money, and patience, we have learned to identify metal alloys that resist corrosion, to find methods of treating the brine itself to inhibit scaling, and to engineer our systems with mechanical features that simplify the maintenance of lines, vessels and wells. These lessons will, we believe, soon enable us to unlock the geothermal energy potential of the Imperial Valley, often described as the "Saudi Arabia" of geothermal energy.

Of greater nationwide importance is the other alternative energy source we are developing--the oil shale deposits of the western United States. The recoverable oil locked up in these vast deposits is equal to some 1.5 trillion barrels--several times the known oil deposits of the Middle East.

Later this year we expect to begin operation of the nation's first commercial shale oil plant, a 10,000 barrels per day facility located on the western slope of

Colorado near the small town of Parachute. This plant is the culmination of nearly 40 years of research and a Union capital investment of about $625 million.

I think it's of interest to describe this pioneering project in some detail.

The overall complex has three main elements: a 12,000 tons per day underground room and pillar mine, a retort in which oil shale rock is heated to release 10,000 barrels per day of crude shale oil, and an upgrading plant to remove impurities and convert the raw shale oil into a high quality synthetic crude.

The unique upflow retort, standing 108 feet high and using technology created by Union, occupies a five-acre bench carved out of the mountainside 1,000 feet above the valley floor.

The raw shale oil released from the rock will be moved by pipeline to the upgrading plant in the valley below where it will undergo Union Oil developed processing to remove impurities and to increase its hydrogen content.

The resulting product is a high quality crude oil which can be converted into a full range of petroleum fuels in any of the nation's refineries.

If you have not already done so, I invite you to visit Union's shale car exhibit here at the conference. Each of the petroleum products--from the fuel to the greases--used in this car was produced from Colorado shale oil at our Research Center. Each of these products performs perfectly.

We have every expectation that large-scale application of our shale technology will be successful. And so do those who have licensed it from us for their own future operations.

Obviously, we will at first tap this immense resource only in a modest fashion. But in proving and improving our technology now, we expect to pave the way for larger and more efficient development as economics allow and national security requires. To this end, we have done the preliminary engineering for an 80,000 barrels per day expansion, and have submitted an application to the Synfuels Corporation for assistance in building the first 20,000 barrels per day increment of this expansion.

America's third area of energy progress lies in improving its federal energy policy. After a decade of painful experiences, we have at last returned to free markets, at least for oil products. (Natural gas, as I will mention shortly, remains a problem.) Free markets have their problems too--indeed, we're having them today--but these problems are far preferable to those created by bureaucrats caught up in the political pressures of our free-wheeling democracy. Not-so-incidentally, one of the happy side benefits of the decade of controls is the general understanding that the oil price and allocation controls of the 1970's made the oil crises worse rather than better.

Our federal energy policy has also created two needed elements of our national security program--a strategic oil reserve to help us through the early weeks of a future oil import cutoff and a major program (managed by the Synfuels Corporation) to provide incentives to the private sector to develop new unconventional sources of oil and gas.

The one remaining area of federal energy controls is in natural gas pricing. Because of conflicting political pressures--producers vs. pipelines vs. utilities vs. consumers--Congress has thus far been unable to come to terms with this issue, despite repeated efforts to do so. The existing natural gas control program has led to an almost unworkable network of natural gas prices--depending upon the age of the discovery, its depth, whether onshore or offshore, plus a dozen other criteria. The confusion, the disincentives, and the waste are obvious. President Reagan, Energy Secretary Hodel, and the Congress are gearing up for one more round. I wish them luck in finding the clear and simple path to eventual full price decontrol.

Let me now shift my sights to a few observations about America's future energy problems and progress.

As I see it, our major problem is keeping our proper long-perspective while the current oil oversupply and price situation works itself out. I do <u>not</u> see this current situation as evidence that America's oil problems are over, that OPEC is finished, and that oil consumers can return to their old, careless habits.

Rather, I believe that some relatively short-term swings in world oil production and oil usage, coupled with both a global business recession and a long-term structural change in the end uses for oil (it's becoming principally a transportation fuel)--all have combined to produce a temporary oversupply. A number of likely future events, including a return to a strong world economy or another Middle East war, could quickly wipe out this oversupply, just as they have twice in the past decade.

We must not forget that the world's basic energy supplies--its fossil fuels--continue to be diminished, year by year, while the world's desire for higher living standards--and thus its needs for energy--continue as strong as ever. It's only a matter of time before these forces once again come together in a way to cause the energy supply-demand balance to shift from "glut" to "shortage." And when that happens, America will once again see real energy prices back on the trend line of recent years, and we will once again come face to face with our vulnerability to a cutoff of foreign oil.

This means, to me, that America must continue to provide the needed incentives--as well as the federal offshore exploratory lands--to encourage domestic oil production as much as possible. A reasonable long-term goal is to at least hold our oil production at today's level of about 8-1/2 million barrels per day. In addition, we should keep up our efforts to stimulate energy conservation, free natural gas from controls, encourage basic energy research and development, and continue the strategic storage program and the synfuels program. Finally, we must prove to the public that we can provide safe and reliable nuclear power.

These are sound and reasonable objectives for America's future energy policy. If followed, America will continue its past progress and will have the energy it needs for a secure and prosperous 21st Century--now less than 17 years away.

Thank you for this opportunity to be with you today.

ENERGY REALITIES IN A CHANGING OIL MARKET

DR. ULF LANTZKE
EXECUTIVE DIRECTOR
INTERNATIONAL ENERGY AGENCY

Introduction

When I look at the number of people attending this tenth Energy Technology Conference and at the great number of practical ideas that are being exhibited, I get the distinct impression that I am not alone in thinking that the energy problem has not been solved. This despite the current conventional wisdom that we can all go home, as ever cheaper oil supplies will be around long after we have finished our stay on this planet. This is a view difficult to disprove in advance. However, I want to use this occasion to point out what I feel the basic realities of our energy situation are, and the role of energy technology in dealing with these realities.

Role of Energy Research and Development

As many of you know, there has been a distinct shift in attitude regarding energy R & D. in the last two years. This has probably been most forcefully expressed in the United States, but the shift has been seen in most other industrialized countries too. Two factors have converged to stimulate a more critical examination of energy R & D policy.

First, the current recession has forced governments and companies in the private sector to see where current expenditures could be reduced. Governments have been hard hit because reduced tax receipts have been accompanied by unprecedented demands on relatively generous social welfare systems which were built up in times of prosperity. Companies have reduced long-term investments because of depressed sales with no satisfactory indication when demand would pick up.

The present situation is not a monument to careful planning and forethought. We should not forget the driving role of the 1979/80 oil events have had in bringing this situation about. It is no coincidence that the erratic upward curve of oil prices is practically a mirror image of the downward curve of all indicators of economic progress.

The second factor affecting investment in energy R & D is the current oil market situation. With oil seemingly in abundance, why invest in alternatives? The oil price increases of 170% that took place in 1979 and 1980 had to result in contracting demand for oil. What we saw in 1981 and 1982, and and continue to see this year, is nothing more than a textbook demonstration of basic economic principles. If one raises the price of a commodity too high, then demand will be affected. As demand falls significantly below available supply, the price will drop. It has, however, been a very painful demonstration, as the unemployment and industrial production figures show.

However, we should not make it even more painful by drawing the wrong conclusion from the current drop in energy consumption, and particularly oil consumption. In the OECD area we estimate that in the period 1973-1982, energy use relative to GDP decreased 15% and oil use relative to GDP decreased 29%. The conclusion that some seem to be drawing is that this significant decrease means that energy demand will continue to decline or, at worst, stabilize around present levels. If this were accurate, then clearly energy R & D budgets are obvious places to practise fiscal restraint.

I would be more cautious in drawing such conclusions. Reducing the very high unemployment in the OECD will require relatively high economic growth, averaging 3.2% per year in the 1985-2000 period. This will inevitably mean an increase in energy demand and particularly in oil demand if alternatives are not readily available. I do not think we are yet in a position to declare that energy will no longer be a constraint to economic growth.

Energy R & D Priorities

This environment I have described poses a stern challenge to those involved in energy technology. The challenge is to place your work in an understandable political context. Governments, and companies, are besieged with more worthy initiatives than they can possibly cope with. Those that will receive attention, and ultimately serious consideration, are those which are perceived as making a meaningful contribution to larger objectives.

It may not be easy to see the political context in which a particular technology or R & D program should operate. But a clear opportunity exists in the context of reviewing overall energy security. There are two basic elements of energy security as I see it. First, coping with possible disruptions of specific energy flows; second, ensuring that there is an overall sufficiency of energy supplies. Improving overall energy security requires both:

- mitigating the effects of supply disruptions when they occur.
- maintaining a balance between energy supply and demand and improving the fuel mix; and

Clearly, given the long-term aspect of energy technology, most of the opportunity for you lies in improving the energy supply mix. It is within the context of improving energy security that energy technology will find its greatest political relevance. We must then ask ourselves if sufficient effort is being put into energy technology to remove energy as a constraint to overall economic growth. Let me review the critical technologies as I see them.

Existing Technologies

First, we have existing technologies which could contribute further to improving our energy position by further market penetration.

Nuclear energy is a clear case where progress of an industry has been impeded by factors that are not purely technical or economic. I have little doubt that nuclear power is extremely safe technically.

We should recognise that broad-based political support for nuclear energy is weak. This is especially true in the United States where we see the greatest potential for increasing the share of nuclear power in the overall supply mix. Concern centers on the safety of reactor operation, on non-proliferation issues, including that of reprocessing spent fuel, and on the problem of the long term isolation of nuclear waste.

Nuclear technologists can help build the necessary political base for resolving these issues. In the area of nuclear waste, a cooperative nuclear waste demonstration program, bringing together the key countries, would be an important step forward. Such a program basically would require coordination of existing and planned national programs with a full exchange of information. But it is a necessity if, at a time when our economies should be benefitting fully from nuclear-supplied electricity, they are instead still hostage to waste storage problems.

Because of its resource base in industrialized countries, coal has probably the greatest potential to be a major, reliable contributor to our energy security. Coal's greatest handicap is its image of being a dirty fuel. This image must be dispelled if widespread use of coal is to be achieved.

The Coal Industry Advisory Board of the IEA has just completed a major review, based on actual case studies, of environmental considerations in expanding the use of coal. It cites environmental concerns as one of the major constraints inhibiting the expanded use of coal. While continuing the necessary technical work in these areas, we must move quickly to facilitate the commercialization of existing technologies able to remove pollutants in an efficient, cost-effective way. This will require a coalition of effort among technologists, potential customers and energy policy-makers. No group alone can remove the barriers to market penetration. I note with satisfaction that many of these coal issues have been discussed in this conference.

There is one other energy source which should be mentioned, particularly as it has also been much discussed at this conference. That is renewable energy. At the IEA, we estimate that all renewable sources could provide 10-11% of OECD energy supply by 2000. Most of this will be accounted for by hydropower and firewood, leaving perhaps as a modest contribution as 1 1/2 to 2% for geothermal, solar, wind, etc.

While relatively small in percentage terms, renewable energy continues to be a significant regional contributor with OECD countries but particularly in developing countries. It will contribute to a basic diversification, over the long-term, of available energy sources.

Among all the alternatives to oil, renewables probably have been most influenced by political trends in recent years. Much of the discussion on renewables, I am afraid, has been characterized by a desire for seemingly benign and relatively cost-free energy sources to meet increasingly sophisticated energy needs. If renewable energy is to grow out of the 'fad' stage, which I am confident it will, we must focus on those renewable energy technologies which can make a meaningful, cost-effective contribution.

Longer-range Technologies

There are two technologies which have longer range commercial viability but which, nevertheless, can not be neglected. I refer to synthetic fuels and to fusion energy. Both hold great promise for the future, but their treatment in funding has been interestingly different.

Synthetic fuels have seen an abrupt shift in fortune. In their report issued less than two years ago, the IEA High Level Group for Energy Technology Commercialisation estimated that synthetic fuels from tar sands, oil shales and coal could reach 1.2 mbd by 1990 if then current government policies were continued. The possible output for these fuels by 2000 was estimated at 3.5 to 8.8 mbd.

This report was written by serious, level-headed experts. Yet today synthetic fuels have been buried by cost considerations, not least of which have seen major cost escalations. The plans of the mid-seventies were undoubtedly too ambitious. Yet we will need to know, by the end of this decade, how the technology works on a commercial scale. This way commercial exploitation will not be hindered when the contribution of synfuels could be needed in the late 1990s. Here is a clear case where, for clearly understandable economic reasons, the lack of investments in technology today may cause problems in fueling our economies tomorrow.

Fusion energy is more complicated, and its commercial viability is further off. We are beginning to see that the cost of further progress will make inordinate demands on some national budgets. While national fusion energy budgets have held relatively steady, the costly nature of the long-term development of fusion energy reactors will require risks to be shared on an international basis. Building support for such a program will not be easy given vested interests within countries. All those involved in the fusion R & D should seriously examine how international cooperation, backed by appropriate political support, can place fusion research on the road to power on line.

Relevance of Energy R & D

I have outlined where I feel the priorities for energy R & D lie. I use the word 'priorities' with reason. Given the current recession, it is clear that all sectors of the economy will have to justify current and planned expenditures. Energy technology is not, and should not be, an exception. But neither should we lose sight of the critical role technology development will play in ensuring stable, reliable energy supplies and thus in sustaining economic growth.

From reading the current press, both popular and trade, one is inclined to conclude that the energy world of 1983 is very different from the one we knew in the period 1973 to 1981. First we had an era in which the problem of energy, and in particular oil, was presented as an insolvable one. Now we have apparently moved into a phase where these problems, or some at least, are no longer of concern.

Some governments have shifted from an active energy policy to one of letting the market place set all the fundamental priorities. There is a temptation now to think that things will take care of themselves; that we can relax efforts to set the general direction of policy. I agree that the market must be the prime allocator of resources. But there are cases such as in the pre-commercialization stage of new technology, where the market place alone cannot give the right signals to investors. The market place alone would not have brought nuclear power to the consumer; the same, I am afraid, will be true for synfuels or fusion.

These shifting perceptions of our energy situation ignore basic realities. It is not exaggerating to say that the so-called 'solution' of the energy problem is in large part a result of the deep economic problems facing industrialized countries. When OECD unemployment has increased from 19 million in 1979 to an estimated 33 3/4 million this year, one should not be surprised that energy use has declined.

Some macro economists suggest that low economic growth over the short term has made the energy problem manageable because of reduced energy demand. The surface truth masks a larger problem. With low economic growth, there is likely also to be a pronounced slowdown in investment in non-oil energy supplies. This is exactly the investment I feel is necessary if we are serious about maintaining adequate energy security. These are investments, such as coal and nuclear generating plants, oil shale and tar sands, which will be necessary to provide needed energy in the early to mid-1990s, if we want to avoid falling back on oil as the only readily available source to fuel revitalised economic activity.

When the economy picks up, a development which all of us must subscribe to, and as incomes rise, there is likely to be an increase in energy demand. How much we really do not know. But we do know that there is only one energy source which can be readily turned on and that is oil. I need not remind you what kind of situation we would find ourselves in if an economic recovery depended on substantial additional supplies of imported oil to keep it going. The world economy can not, should not and must not have to tolerate a third oil shock in this century.

Conclusion

I want to conclude by saying a few words to those of you responsible for investments in energy technologies. You are not to be blamed if you are confused in reading daily reports about the likely path of oil prices. Obviously, we must be aware of the daily developments in the oil market. But we need not be mesmerized by them. Currently, conventional wisdom favors a radical change in the price of crude oil. As a consequence, I would expect to see a lot of sad faces here.

I am not so optimistic about the inability of oil producers to see where their own interests lie. I suspect that most energy policy-makers in non-OECD oil producing countries have come to the same conclusion we have on likely future demand for oil. There is little I can see in actual market conditions which would justify price levels approaching those we had five, or ten years ago.

What would seem the most plausible in the current situation would be a modest reduction in oil prices, with some assurance of a substantial period of price stability in nominal terms. Such a development would give a badly needed boost to the world economy. But it would also enable us to follow through on the sensible investments in energy technology. These are undoubtedly tough times economically and energy technologists are not immune. But you can benefit by the rationalizing which will permit the best projects to go forward. The field as a whole will benefit if the current economic climate leads you to placing your work in the broader context of assisting energy security. You will certainly find energy policy makers willing to assist you in this effort.

THE U.S. CANADIAN NATURAL GAS RELATIONSHIP: AT THE CROSSROADS

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Introduction

It is a pleasure to be here today to review and discuss this session's topic, Importing Canadian Gas: Policy and Pricing Issues, an issue to which my office has been devoting considerable time in recent months, which is only one modest aspect of this year's impressive AGA Energy Technology Conference program. Canadian gas imports to the U.S. is important to both countries and is an issue that has received much attention in recent months in the media on Capitol Hill, and in diplomatic discussions between our two governments.

The U.S.-Canadian natural gas relationship is at an important juncture in early 1983. As the Administration considers how best to proceed with new domestic decontrol legislation, political and economic pressure is building rapidly to oblige Canada to lower its gas export prices to a range competitive with available domestic gas and alternate fuel oils. As the heating season wears on and the new Congress begins to demand action on the problem, pressure for a legislative solution to the gas import issue is likely to intensify.

Canada, on the other hand, is reluctant to alter the status quo, cognizant that virtually any price or pricing formula modification will not increase sales appreciably in the short term, and thus only reduce revenues. Moreover, volumetric take-or-pay conditions on several of their export contracts ensure that substantial volumes of gas will continue to be purchased by American buyers regardless of the marketability of Canadian gas.

Canadian earnings are at an all time high, rising from approximately $2.5 billion in 1979 (for roughly 1 Tcf) and nearly $4 billion in 1982 (for 800 Bcf), to an expected $5.5 billion in 1983 (on approximately 1.1 Tcf) at the current border price. The 1982-1983 volumetric increase is due to the start up of the Northern Border pipeline, a "prebuilt" segment of the Alaskan gas pipeline. Clearly, Canada is benefitting from pricing arrangements now in place, and it is in no hurry to see those arrangements change.

Three central elements contribute to the current difficulties regarding Canadian gas exports. The first element, known informally as the Duncan-Lalonde understanding on Canada's substitution value pricing formula, accepts in principle that Canada will price its exported gas based on the Btu equivalent price for imported crude into eastern Canada (i.e. the substitution value formula) so long as the price meets U.S. regulatory approval required under section 3 of the Natural Gas Act. The second element is the uniform border price, a scheme adopted by the U.S. designed to ensure that no U.S. regional or state market would be forced by any government to be at a disadvantage over another in terms of the price paid for Canadian gas. The third element is the take-or-pay clauses on U.S.-Canadian contracts restrict natural gas trade adjustments by locking in the volumetric minimums that importers must take to avoid penalties or suspension of their contracts.

These elements combine to produce two unfortunate effects to our bilateral gas trade. First, the system is exceedingly rigid, preventing much needed flexibility for buyers and sellers to adjust to a rapidly changing natural gas environment. Second, Canadian gas pricing is insensitive to market signals where it must compete with domestic gas, competitive fuel alternatives, no. 2 and no. 6 fuel oils.

The Current Situation

Recent events in Washington underscore the urgent need to revamp this bilateral import structure. On the Hill, scores of House and Senate members have made their views known to the President in recent correspondence, calling on the Administration to enter into immediate price negotiations with Canada and Mexico to lower the export price. Members of Congress have also introduced legislation that would oblige Canada to submit an "acceptable" border price to the Secretary of Energy within six months, or face suspension of their import authorizations. Finally, some members have even travelled to Ottawa to meet with their parliamentary colleagues and Canadian government officials to underscore American concern and desire for immediate action. As constituent pressures continue to build in the face of perceived inaction in Washington and Ottawa, Hill efforts to force the issue will undoubtedly escalate.

At the same time, U.S. regulators have come under increasing pressure to reexamine pricing and take-or-pay terms of existing contracts. Industrial gas end-users, distribution companies and state public utility commissions are seeking price relief to protect their businesses, shrinking natural gas markets, and consumers, respectively.

On January 18, the DOE, with State Department participation, held an Open Conference on Canadian and Mexican imports. Comments from pipeline producers, distributors and consumer advocates signalled clear agreement that the price was in most cases well beyond any reasonable competitive level. Moreover, gas importers overwhelmingly supported movement toward an import pricing scheme that would permit the buyers and sellers to negotiate prices for all or at least part of the gas imported, subject to bilateral regulatory approval.

With these developments in mind, the State Department chaired bilateral energy consultations February 1st with our Canadian counterparts under the revived Energy Consultative Mechanism. While a number of energy issues were discussed, natural gas was the central topic of concern to both sides. From the U.S. vantage point, we emphasized the severity of current situation and underscored our urgent need to restore market flexibility and sensitivity to our bilateral gas relationship. The Canadians acknowledged a need to examine the implications of this problem for the conduct of our bilateral gas trade and agreed to meet with us again in the near future to examine this issue in greater depth.

We are hopeful that these diplomatic discussions will result in due course in pricing arrangements that protect in a mutually satisfactory manner both the short and long term benefits that both of our countries currently receive from our gas trade. We are dependent on one another here in North America, where natural gas markets exist in relative close proximity to abundant supplies of natural gas. Letting this natural economie complementarity operate and flourish is in our mutual interest.

This brings us to the logical all important next question: What new pricing arrangements can we put in the place of the existing rigid structure? Indeed, I look forward to some useful comments and discussion from the conferees today on this very question. Ideally, any new scheme must be market sensitive and flexible with minimal government interference.

I believe, in principle that an important starting point for any new scheme must be to introduce buyer-seller negotiations subject of course to regulatory approval in both countries. Support for this approach is strong in the private sectors of both the United States and Canada and should be given a chance. From Canada's standpoint, it would ensure that Canadian imports would be in the best possible position to protect and expand their U.S. market share as the NGPA-led price decontrol on its course in early 1985. With pricing flexibility restored to bilateral contracts, U.S. buyers would be in a much better position to make long term purchase commitments for Candian gas and enable Canadian producers to resume with greater cofidence some of the exploration efforts that have made Canada a world gas and oil export leader.

From the American standpoint, it would allow much needed adjustment in the current market situation and provide an orderly market oriented structure to govern future U.S. needs for Canadian gas. With the possibility of a steep deliverability drop off late in this decade, this new market structure would permit needy buyers to attract new imported supplies quickly and effeciently at market dertermined prices.

I'll close at this point and thank you for your indulgence. I look forward to the upcoming discussion and whatever questions you may have.

THE ROLE OF THE FEDERAL GOVERNMENT IN THE NUCLEAR OPTION

Dr. Thomas A. Dillon
Principal Deputy Assistant Secretary for Nuclear Energy
United States Department of Energy

During his campaign, President Reagan repeatedly characterized nuclear power as a critical component of energy stability for our country. Since coming to office just over two years ago, he has initiated a series of actions that clearly reiterate and reinforce the Administration's commitment to the nuclear option. In his Nuclear Policy Statement of October 8, 1981, he identified the problems that undermine long-range nuclear viability and set forth an agenda for the appropriate Federal role in finding their solutions. Now is an opportune time to take stock of the progress that the Administration has made in fulfilling that agenda.

NUCLEAR PROBLEMS INHERITED BY PRESIDENT REAGAN

The condition of the nuclear industry in the United States today is a paradox. On one hand, nuclear energy is providing safe and reliable electricity to a growing number of U.S. citizens. In spite of rapid capital cost escalation, it has an average 10 percent cost advantage over coal, and both options produce energy far more economically than oil- or gas-fired plants. Moreover, projections for the future indicate that nuclear power will continue to be a highly competitive source of electricity. By the late 1980's, as plants now in the pipeline begin operation, nuclear-generated power will double, accounting for more than 20 percent of our electricity. Beyond the current decade, however, the prospect for nuclear expansion is in serious question. Indeed, since 1978, no utility has ordered a nuclear plant and more than 50 plants have been cancelled, bringing total cancellations to 102. Why?

Certainly one of the causes has been the weakness in our economy that has been a persistent problem since the oil crisis of 1973-74. Skyrocketing oil prices in the mid-1970s were soon followed by major cost increases in all energy supply options. Expensive energy led to conservation and, when coupled with the weak economic growth, a decrease in energy consumption and load growth forecasts resulted. Utility managers, rethinking their growth plans, backed away from new construction projects. For the few new plants that have been committed, coal has gotten the nod because of its lower capital cost and shorter construction leadtimes.

In addition to general problems with the economy, President Reagan inherited a number of problems specific to the nuclear option. A cumbersome licensing system has helped add costly years to the leadtime for designing and constructing a nuclear plant. The impact of this problem is illustrated by the projections for the capital cost of a plant entering operation in 1995: they are 14 times the cost of a plant that began operation in 1973! The bulk of this increase is found in time-related costs that have escalated by 5000 percent. In contrast, direct costs have increased by only 330 percent and indirect costs by 1370 percent.

Another major nuclear deterrent has been the failure to complete closure of the back end of the fuel cycle. Despite exhaustive studies evaluating the alternative methods for disposing of radioactive nuclear wastes, the actual isolation capability has not been demonstrated. As a result, a complex technological task--but one with a number of potential satisfactory solutions--has been allowed to escalate to an issue of major public concern.

Finally, the logical progression of fission technology from a near-term energy option to a long-term, essentially inexhaustible energy supply was interrupted in 1977 when the previous Administration attempted to cancel construction of the Clinch River Breeder Reactor. Although CRBR funding was continued by Congress, the Project paid a heavy price in terms of slipped schedules and cost overruns that resulted from the ensuing political debate. The momentum of the U.S. breeder program suffered substantially and the United States forfeited its leading position of influence in international advanced nuclear development.

Underlying these problems is a history of confusion over the proper role of the Federal Government in developing nuclear power. In a number of instances, private sector managers have initiated nuclear ventures on the assurance of strong and stable Government support only to have the promised backing withdrawn in midstream. Clearly, a paramount obstacle to renewed nuclear commitment and investment is a perception by both utilities and the financial community that there are great risks rooted in potential policy vacillations and regulatory uncertainty at the Federal level.

THE REVISED NUCLEAR POLICY

It is on these formidable problems that President Reagan has concentrated the main thrust of his nuclear policy. The specific initiatives announced in the October 1981 Policy Statement called for Government action to:

- improve the nuclear licensing process and the entire institutional and financial environment of the electric utilities;
- swiftly establish a nuclear waste disposal capability;
- demonstrate breeder reactor technology including expeditious completion of the Clinch River Breeder Reactor; and
- stabilize long-term policies regarding commercial reprocessing.

At the Department of Energy, we realigned organizationally to conform with and be responsive to the new policy. A "management-by-objective" strategy was introduced into the nuclear programs that allowed for concentration on major issues and elimination of activity not directly related to the President's policy initiatives.

Also included in the new policy is the clear articulation of the respective responsibilities of both Government and the private sector in nuclear development. Government must play a role in providing for the viability of nuclear power by

- stabilizing Federal policy for time periods commensurate with the leadtimes required in nuclear development;
- removing unnecessary regulatory impediments that have developed over the years;
- fulfilling its legislated responsibilities for certain elements of the fuel cycle, such as high-level waste disposal and uranium enrichment; and

- o conducting high-cost, high-risk research and development that is of significant benefit to the Nation, but beyond the capability and resources of the private sector.

Ultimately, however, it is the nuclear industry that must make the decisions for expansion and accept the responsibility for deployment.

In the remainder of my remarks, I would like to focus on several examples of the Federal role in nuclear development as it has evolved over the past two years.

WASTE MANAGEMENT PROGRESS

As I'm sure you know, on January 7, President Reagan signed into law the Nuclear Waste Policy Act of 1982. In doing so, he applauded the bipartisan effort that had enabled "the long overdue assurance that we now have a safe and effective solution to the nuclear waste problem."

The provisions of the Act include all the major elements that the President had earlier identified as crucial to a coherent nuclear waste system. Specifically,

1) a strong Federal commitment to permanent geologic disposal as the ultimate solution to the waste problem;

2) a mandated schedule for construction of the first two repositories in a regional system;

3) a system of fees paid by utilities to fund waste activities that will permit the full cost of nuclear power to be borne by its beneficiaries;

4) a method for extensive State participation in the siting of waste facilities and a means for resolving State objections;

5) the development of proposals for monitored retrievable storage as an interim step toward permanent disposition;

6) a Test and Evaluation Facility to support generic research and development applicable to the first repository;

7) a limited, temporary Federal storage program to assist utilities with severe near-term storage problems; and

8) a clear distinction between the handling of civilian and defense wastes.

Passage of this landmark legislation is visible evidence that in the United States we have reoriented our waste management activities away from a study mode and are now concentrating on actually deploying an operational system on a mandated, legislated schedule. Our current timetable for bringing the first repository on line calls for the near-term nomination of five candidate sites. Each nomination will reflect extensive evaluation, including the preparation of environmental assessments. Three of the five sites will be recommended for detailed characterization including exploratory shafts at depth. A construction authorization request for the first repository will be submitted to the Nuclear Regulatory Commission in 1987. Operation is scheduled to begin no later than 1998. Schedules have also been established for a second repository and a test and evaluation facility. With passage of authorizing legislation, we believe our efforts to establish a national waste disposal system are substantially strengthened.

During the past two years the results-oriented approach that we introduced at the Department has proved particularly successful in our waste management program. Technical progress has placed us in an excellent position to swiftly and effectively implement the Act. An example is the basalt work on our Hanford reservation in the State of Washington. Before the Act was signed into law, the technical program had progressed into the site characterization phase and construction of an exploratory shaft was underway. A special provision of the Act allows this work to proceed without delay.

REGULATORY AND LICENSING REFORM

A concept of effective Government that the Administration has advanced most vigorously is the stabilization--and, where possible, the reduction--of Federal regulations. As I stated earlier, reform of the current, outdated procedures for the licensing of nuclear powerplants is long overdue. Accordingly, we have consulted extensively with government, industry, and private organizations to identify areas in which the system could be made more efficient.

Our first recommendation relates to backfitting of plants, which in the past has led to significant increases in costs and schedules. Our recommendation is to add discipline to the review process by requiring centralized review and Commission approval of backfits. In addition, factors such as cost and the increase in overall plant safety must be considered in backfit decisions. Secondly, we are recommending a one-step licensing process that could save substantial construction time by completing the design early, allowing the Nuclear Regulatory Commission to issue a license that would authorize both construction and operation. We believe a natural adjunct to one-step licensing is preapproval of sites and designs. This would permit utilities to select from and match together standardized reactor designs and preapproved sites. Finally, we are recommending major changes in the hearing process. Our revisions would reorient the formal hearings toward consideration of important disputed areas and those issues that are critical to final licensing decisions.

By providing a regulatory process that offers predictable criteria for siting, design, and constructing powerplants and predictable schedules for authorizing, constructing, and operating these plants, significant plant capital cost savings will result. We believe these changes in the regulatory system will encourage a resurgence of nuclear plant orders, leading to savings in consumer electric bills and assurance of diverse energy supply.

AGGRESSIVE BREEDER DEVELOPMENT

Yet another element of the President's nuclear policy on which we have concentrated our efforts is the continued development and demonstration of the breeder reactor system. The Federal Government's role in breeder development is based on the potential long-term benefit to U.S. energy security and the inability of industry to shoulder alone the inherent high development cost and initial technical development risks. Accordingly, breeder efforts have been directed toward an aggressive program of accomplishment designed to have the technology ready when economic factors signal the need for commercial breeder introduction. A basic element of the development strategy has been to share costs and coordinate research with industry, where practical, with the purpose of transferring both the technology and the responsibility to the private sector as rapidly as is technically and economically feasible.

A major thrust of our breeder effort has been to reorient and streamline the Clinch River Project, with the result that we have significantly accelerated the construction schedule. The design--which has been continuously updated to maintain the Project at the forefront of technological advance--is now approximately 90 percent complete, and more than 70 percent of the major equipment and components have been delivered or are on order. Consequently, we have reached the stage where our estimates for completion costs are relatively firm.

The licensing process for CRBR is moving exceptionally well. Last August NRC granted our request to begin site preparation, and in September work was initiated at the site near Oak Ridge, Tennessee. The environmental part of the licensing process has been completed. Meetings with NRC staff to review Project safety issues were held during January. NRC is expected to issue its Safety Evaluation Report this month (March), with hearings beginning in June. Permission to begin construction is expected by November of this year. I would like to point out that because of licensing progress over the last year, we have been able to accelerate our construction schedule by six months. Overall, CRBR licensing is proceeding at a faster pace than that of any light water reactor over the past five years. This record performance attests to the technological sufficiency of the plant design.

Our current schedule is to bring Clinch River on line in 1989. Its purpose is to prove the operational capability of an intermediate-size plant and to enable the research and development necessary to advance to a full-size commercial plant. In keeping with the objective of moving the breeder option into the marketplace, the utilities have already pledged $340 million (including interest) to the Clinch River Project. In addition, proposals for greater participation from the private sector are being developed by an investment task force of industry, utility, and Government representatives. A progress report on task force findings will be forwarded to Congress by March 15.

SUMMARY OF U.S. PROGRESS IN REVITALIZING THE NUCLEAR OPTION

The nuclear goals that the President has set for the country are ambitious, and the problems facing us are deeply rooted. There are no simple solutions--only intelligent choices. I believe the progress to date gives us a basis for optimism.

- We have reoriented the waste program from protracted study to productive demonstration. Our march toward a permanent repository is on track and the passage of the high-level waste bill brings statutory permanence and authority to our plans.

- We have developed a realistic plan for licensing and regulatory reform. If the recommended measures can be implemented, a giant step will be taken in returning investment viability to nuclear energy.

- Congressional funding for CRBR--admittedly a close victory--has allowed us to continue the careful, safe and timely scaleup of the breeder technology. Strategies to encourage a larger proportion of private sector investment are being developed.

In no way am I implying that all is now rosy with the nuclear option. Our strategy for success is still evolving in certain areas. Much remains to be done, and some of our objectives may not be realized for a long time. On balance, however, I believe we must realistically judge the achievements of the past two years as an excellent beginning.

I want to close with the President's remarks when he signed the Nuclear Waste Policy Act. He strongly reaffirmed his support of nuclear power by saying,

> "This Administration is committed to the use of nuclear energy as a crucial element in the enormous task of supplying America's energy needs. American industry has developed the strong technological base for the production of electricity from nuclear energy and we owe it to our people to make it possible to use this technology to better their lives."

The Federal Government has a unique and critical role in ensuring that opportunity for our Nation.

Part II

ENERGY ANALYSIS, PLANNING AND REGULATION

Each year a number of important studies are completed that examine the impacts on our energy and socio-economic systems of various alternative modes of operation within existing and possible future government and industrial policies. These studies are valuable in making industrial decisions and guiding the government in establishing new policies.

This section presents the results of a number of specific studies and makes recommendations for future action.

U. S. POTENTIAL GAS SUPPLIES

J. C. Herrington

ARCO Exploration Company, Dallas, Texas

(Also Chairman Potential Gas Committee)

Introduction

In past years, some industry and government personnel have regarded the Potential Gas Committee's estimates of the future recoverable natural gas resources to be unduly optimistic. Results obtained by industry in the past few years, however, certainly support the Potential Gas Committee's position that approximately one-half of the total recoverable volume of this valuable resource remains to be discovered.

With the relaxation of price controls on interstate gas and the advent of pricing incentives for the hard to recover gas, we have seen an explosion in both conventional and ultra-deep exploration and a much expanded effort in the so called "tight gas" resource areas. In fact, our gas exploration has been so successful that consumers today no longer have to worry about curtailments or price escalations because of a so called gas shortage. Instead, industry has to learn to live with an overall gas surplus.

The volume of new gas discoveries in 1981 actually showed an increase of 19% over 1980 and proven gas reserves showed an increase of approximately 3 trillion cubic feet at the end of 1981. The exploration drilling tempo which had remained high throughout 1981 began to slacken in the first quarter of 1982 when the present recessionary conditions exerted a tremendous adverse effect on the gas industry as a whole. Despite the downward slide in drilling, we still have approximately the same number of wells drilled over all in 1982 as in 1981. Hopefully, new reserves added will also compare favorably with 1981.

In the face of this period of accelerated drilling and good success by industry, the Potential Gas Committee has lowered its estimate of the future gas resource by approximately 37 trillion cubic feet. As of the end of 1982, we estimate the future potential gas resource to be 876 TCF for the entire U.S. Our statement here suggests a paradox, especially since our future resource estimate as of the end of 1980 was 913 TCF.

This report attempts to clear up this seemingly paradoxical situation by explaining some of the intricacies involved in preparing these resource estimates and examines some of the factors which may or may not have an effect on the final result.

Resource Estimates

At a given time, a finite volume of natural gas in-place exists within the rocks of the shallow portion of the earth's crust. This finite volume of gas in-place is the natural gas resource; on this one point, all resource estimators can agree. The amount of this resource which is recoverable now, or in the future, is a function of technology and economics.

Estimates of the Potential Gas Committee include only the natural gas resource which in our opinion can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable.

The Potential Gas Committee's current estimate of the potential gas resource of the United States is as follows:

Probable	Possible	Speculative	Total
192 TCF	355 TCF	329 TCF	876 TCF

In no case should this current estimate of our future gas resource be considered final. Any gas resource estimate is constantly in a dynamic state as it is continually affected by new discoveries and further exploration in both proven trends and new undrilled provinces.

In past years we have been quizzed extensively about the lack of sizeable deviation in successive estimates. The fact is, from region to region, the estimates have varied considerably both positively and negatively. The following chart depicts estimates by years from 76-82 for each of the 12 reporting areas. Major deviations are shown in parenthesis. These figures reflect only the net deviation for the entire area. The changes are much more volatile when considered on a category by category basis. Refer to Fig.1 pp 4 for area locations.

Estimated Potential Gas Supply in the United States
by Geographic Area
(Trillions of Cu. Ft. @ 14.73 PSIA and 60° F)

Area	1976	1978	1980	1982
A	102	121(+19)	86(-35)	84
B	51	53	54	50
C	6	4	3	3
D	54	50	51	47
E	118	98(-20)	81(-17)	78
G	93	85	69(-16)	58
H	64	160(+96)	187(+28)	208(+21)
I	7	6	6	6
J-North	107-157	143	135	123(-12)
J-South	56	53	51	49
K	225	189(-36)	145(-44)	134(-11)
L	40	57(+17)	45(-12)	36(-9)
	923-959	1019(+60)	913(-106)	876(-37)

When we have years with good news such as the initial huge successes in the western overthrust trend in 1976-78, the additions are of such magnitude that the overall decreasing potential estimate is reversed. Currently, despite good news like the Tuscaloosa trend and the yearly increases in the Rocky Mountain area, the overall trend is lower. Discouraging results in areas like the Gulf of Alaska, Atlantic OCS and the Eastern Gulf of Mexico have had a stronger depressing effect.

Already this year, we have received questions about lowering our estimates some 37 TCF following a period of high drilling activity and remarkable success. The truth is, industry is finding the resources already predicted, and they have not, in this period, opened up any new exciting areas with the potential to reverse the downward trend in estimates. Since we are not dealing with a renewable resource, the overall long term scene will be a reduction. We can, however, hope for an interruption every now and then.

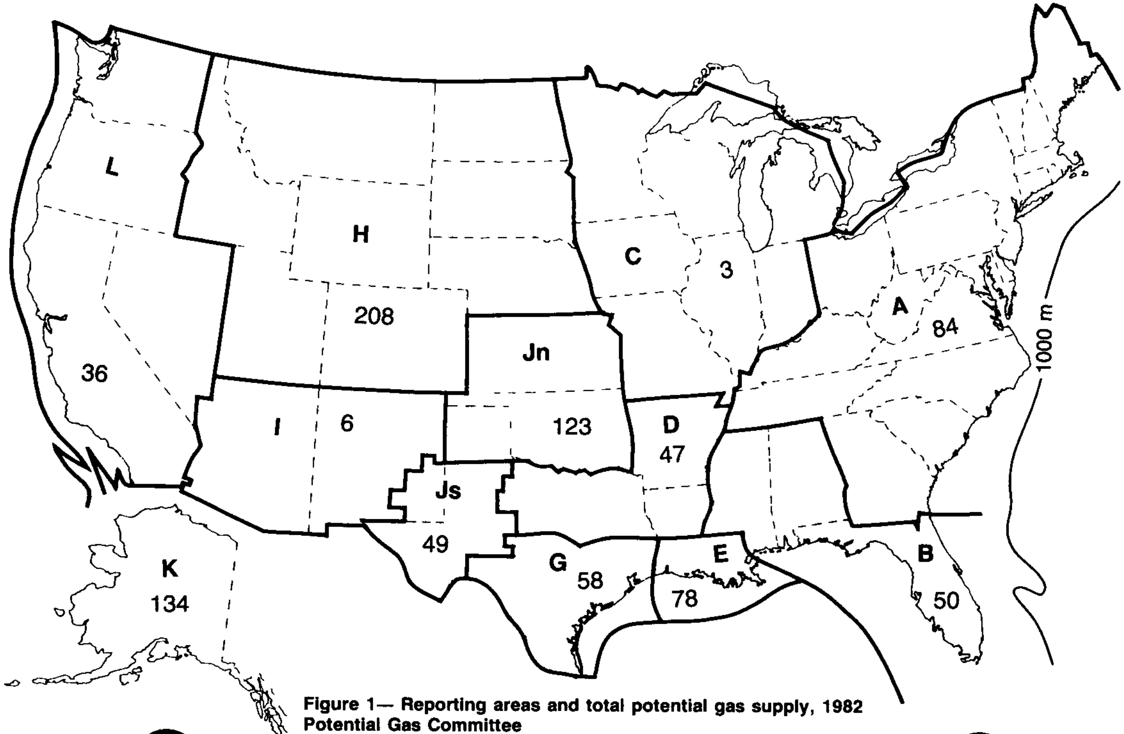

Figure 1— Reporting areas and total potential gas supply, 1982 Potential Gas Committee

The following chart depicts results obtained from exploratory drilling in 1981 by categories.

Exploratory Drilling Results
1981

	Productive Wells	Proven TCF	Dry Wells
New Field W.C. (Possible and Speculative)	1,423	4.5	6,629
Extensions and New Pools (Probable)	3,157	13.5	3,959
TOTAL	4,580	18.0	10,588

A total of 4,580 successful completions in 1981 discovered 18 TCF new gas which is now classified proven and removed completely from the potential category. The reported 10,588 dry exploratory attempts in the same year certainly have served to put a damper on some areas thought to have exploratory potential. A downward revision of 10-15 TCF due to poor results would not be out of line. This amount would also be removed from potential.

If we arbitrarily double these figures to represent both 1981 and 1982, we would expect a transfer of 36 TCF to proven and a deletion of 20-30 TCF because of downward revisions. It takes a lot of exploratory good news to offset this kind of revision and allow any increase in future potential estimates.

The good news is that a downward revision of 37 TCF in 1982 is a huge improvement over the 106 TCF downward revision in 1980. In our opinion, results of the past two years are highly encouraging.

A comparison of estimates from 1980 and 1982 supports this stance.

	Probable	Possible	Speculative
1980 Est.	193 TCF	358 TCF	362 TCF
1982 Est.	192 TCF	355 TCF	329 TCF
Change	-1	-3	-33

It is important to note where and how the changes in potential occur:

- The probable category, with an estimated 27 TCF removed from potential by transfer to proven, only lost 1 TCF in overall potential. This means its volume was replenished by transfer of at least 26 TCF from possible and speculative.

- The possible category which transferred an estimated 9 TCF to proven and suffered some down grading by dry holes only lost 3 TCF in potential. Transfer from speculative to possible is evident.

- The speculative category lost a total of 33 TCF. This figure is encouraging in that it signifies that potential resource is moving from less certain into more certain classifications.

Tight Gas Resource

In December, 1980, the National Petroleum Council concluded its study of tight gas reservoirs in various basins of the United States. This study and others indicated the possibility of approximately 500 TCF future gas supply from this unconventional gas resource.

Members of the Potential Gas Committee became concerned when it became apparent that some people studying our energy resource were inclined to add the 500 TCF of tight gas to the current estimate of the PGC when calculating the total gas resource. A subcommittee was formed to study the situation and a recommendation was made to review all areas where we estimate potential to determine if any of this potential was in effect being counted twice. The review was accomplished in 1982, and we now estimate the Potential Gas Committee's report as of the end of 1982, includes approximately 172 TCF which is considered conventional by the PGC but may be considered as tight gas according to the classification used in many studies of gas from tight formations.

These volumes are considered to fall within the PGC limits because of continuing developments within the industry of commercial production from low permeability reservoirs. These quantities have been incorporated gradually over a number of years into the PGC estimates and, hence, there exists a strong probability for double counting of a major portion of this resource.

Factors Affecting Potential Resource Estimates

Drilling activity has the effect of moving the potential resource from one category to another, but it does not, by itself, have an influence on the estimate of ultimate potential. Results obtained from this drilling, however, may have a decided influence. Better than expected results in a trend may serve to make an estimator more optimistic about anticipated future drilling in the same trend or analogous areas. He could then raise his estimate of future potential accordingly. Worse than expected results, however, would trigger a revision in the other direction.

Price levels do not increase potential estimates as long as they are administered equally across the board. They do, however, stimulate drilling and accelerate recovery of the resource. If by design, a price increase is granted as an incentive for development of a borderline or non-commercial resource, an increase in potential would probably occur for that particular resource provided the price increase is made permanent. It would be proper for the inclusion of this resource to be so noted in the estimate.

Supply and demand factors do not influence the potential resource, however, they do have a decided influence on acceleration of recovery. As an example of the Price-Demand scenario, we can take a look at the Anadarko Basin. Deep exploratory drilling in the basin in the 72-76 interval had sparked an interest in the deep section and had caused a prominent revision upward for the deep potential. Drilling remained slow, however, because of poor economics with an average of around 50 or so active locations. In anticipation of a strong price increase to be granted in 1978 for deep gas, activity picked up in late 1977 and actually doubled in 1978. Rapid increases in drilling were noted each year until in June, 1982, there were 1,042 active locations.

In the early part of 1982, demand slackened and prices dropped dramatically. By January 1, 1983, active locations were down to 620 and are expected to drop still further. Some potential resource will in this case revert to a more or less static classification with its immediate future somewhat uncertain.

Restudy and analysis by new persons coming on the committee has in some cases caused prominent revisions, both positive and negative. By design, the working machinery of the Potential Gas Committee is set up to encourage participation by new members so as to insure a continued flow of new ideas and technological expertise.

Areas to Watch for Future Increases

- The Rocky Mountain area has long been a star in the gas arena and in our opinion will continue to be so.

  A new and exciting play appears to be blossoming around the edges of the central basins where pre-Cambrian basement uplifts may in some cases be thrust for considerable distances over sedimentary section.

  In southwestern Wyoming adjacent to the western overthrust, industry had long been aware of the occurrence of low quality gas. Because of the low BTU content and the cost involved with upgrading the gas to pipe line quality, the area remained unattractive for exploration. New processing techniques, and a growing demand for the major by-product, CO_2, has now elevated the resource to probable commercial status. The consensus is that several hundred TCF of low BTU gas may be developed with a net methane content of around 50 TCF which would be available for market.

  We also anticipate continued exploration and development of the deeper part of the Williston Basin.

- With the perfection of deep water production technology, another round of exploration in the Atlantic OCS can be expected.

- Only a small portion of the Eastern Overthrust has been explored. Some pleasant surprises may come out of this area.

- The Anadarko Basin, already a major deep gas producer, has hardly been scratched in the deep carbonate section of the Lower Paleozoic.

- The Gulf Coast breadbasket may still hold some surprises in the Deep Wilcox, Frio, and Cretaceous sections.

In summary, I have tried to convey to you the feeling that the Potential Gas Committee considers the future gas potential to be sufficient to challenge industry's exploratory ability for several decades.

POTENTIAL NATURAL GAS RESOURCES OF CANADA

by

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The Geological Survey of Canada has been preparing estimates of oil and gas resources of all regions of Canada on a systematic basis since 1973. The estimates are prepared using a probability methodology in which each of the individual exploration plays of the region are examined as to the opportunities for the existence of gas and oil resources. This method which is commonly referred to as the Monte Carlo approach incorporates both objective data derived from exploration drilling, geophysics and various forms of mapping, with subjective opinion of informed experts. Using this methodology the estimates are displayed as frequency distributions in which a range of estimates rather than a single value are presented. For convenience in this talk we will refer most frequently to the average expectation, a value usually between 40 and 50% probability and speculative values which represents probabilities closer to 5 percent. In all cases estimatesof potential are for recoverable or pipeline gas (in the sense of technologically recoverable) but without economic constraint.

Total gas resources of Canada including both reserves and potential are estimated to be in excess of 450 TCF. This potential is identified in many regions of Canada but today we would like to concentrate on the four major regions which contain the bulk of that potential (Fig. 1). They are the Western Canadian Sedimentary Basin , the Mackenzie Delta-Beaufort Sea Region, the Arctic Islands and the East Coast Off-shore Region. For each region we propose to comment briefly on the geological opportunities, exploration activity, the estimated potential, and problems associated with the exploitation of the gas potential. The importance of the problems is perhaps underlined by the statement that in the frontier regions of Canada we now have identified at least eight gas fields which each contain in excess of 1 TCF. Three of these eight probably contain in excess of 3 TCF and yet none of the fields is currently on production, or is likely to be on production, for a number of years.

CANADA GAS RESOURCES (TCF)

	AVERAGE EXPECTATION	HIGHLY SPECULATIVE
1 WESTERN CANADA	159	171
2 MACKENZIE-BEAUFORT	112	147
3 ARCTIC ISLANDS	87	138
4 EAST COAST	72	125

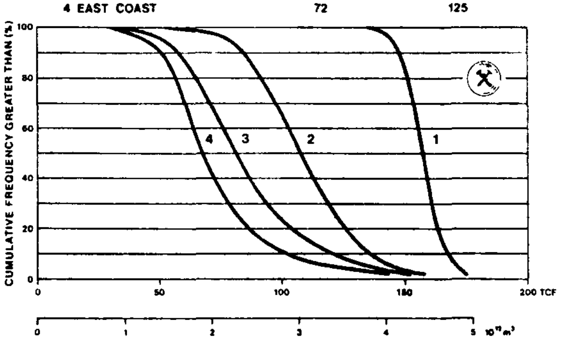


Figure 1: Comparison of estimates of gas potential of Western Canada and three frontier regions.

WESTERN CANADA SEDIMENTARY BASIN

This region consists of the provinces of Manitoba, Saskatchewan, Alberta and British Columbia. It extends from the Precambrian Shield on the east to the Rocky Mountains on the west and lies south of 60 degrees latitude. It is a region in a mature state of exploration where more than 100,000 wells have been drilled and over 9,000 gas pools identified. Our studies indicate that substantial potential remains to be discovered in fairly shallow lower Cretaceous sediments, broadly distributed in Alberta. Other important components include Devonian Reef plays, particularly those in the deeper part of the basin, and the Disturbed Belt or Foothills Region particularly the central and northern parts. Potential can also be identified in terms of quality, pressure, or ease of discovery. It is reasonably easy to conclude that future supplies of gas from Western Canada will be of poorer quality and more expensive than those which have been produced in the past. In addition, Western Canada being a maturely explored basin the point is now approaching where smaller pools are being found with each unit of exploratory activity. Asssuming that the historic rate of finding against exploratory activity can be extrapolated, and using the estimate of potential, the studies indicate that some 20,0000 additional exploratory wells will be required to find the next 35 TCF of gas.

MACKENZIE DELTA - BEAUFORT SEA REGION

This region includes the on-shore part of the Mackenzie Delta and that part of the off-shore extending to the edge of the continental shelf at a water depth of approximately 600 feet. It extends from Amundsen Gulf, west to the Canada-Alaska boundary. The region is underlain by deltaic sandstones and shales of Mesozoic and Tertiary age which thicken rapidly northward to more than 40,000 ft, a short distance seaward from the present delta. These clastic sediments overlie faulted Paleozoic rocks which step down steeply beneath the Mesozoic-Tertiary cover. Although the Tertiary sequences contain the most important sandstone reservoirs, additional reservoirs are present in both Cretaceous and Jurassic sands. Major targets initially were diapiric structures formed by shale intrusion at depth, some of which attain great magnitude. Other targets result from closure associated with roll-over anticlines and growth faults commonly coupled with plastic deformation at depth. Exploration activity began on land, then extended into shallow off-shore regions using artificaly constructed islands. Prospects were targeted primarily in the main deltaic lobes of the present and ancestral Mackeznie Delta. More recently exploration has extended to the deeper Beaufort Sea region where both drill ships and caisson-supported artificial islands now test sedimentary wedges that were deposited in deep water beyond the edges of the ancient continental shelves. Parts of the region such as the area extending west to the Alaska boundary have received very little exploratory effort although there are indications that prospects similar to those found in the Beaufort Sea are present.

More than 170 exploratory wells have been drilled in this region. They have located 18 gas and 14 oil discoveries among them 3 gas pools greater than 1 TCF in size. Total reserves to date, although tentative are estimated to be about 9 TCF.

Estimates of potential for this region were prepared by examining 17 exploration plays. The sum of the potential for the 17 plays indicates an average expectation of 112 TCF of gas. At more speculative levels this estimate increases to almost 150 TCF. It is anticipated that a large portion of the gas potential will in relatively deep water prospects of this region. Difficulties that stand in the way of development of this region include the hostile operational environment, in which rapid movement of sea ice may require special production facilities, and sea bottom scour by ice requiring special consideration in pipelining. Permafrost and gas hydrate conditions add to the drilling and production design problems. Distance from market will contribute measurably to ultimate supply costs.

ARCTIC ISLANDS REGION

The Arctic Islands Region, including the Stable Platform, the Fold Belt and the Sverdrup Basin represents one of the most geologically diverse areas for petroleum accumulation. Exploration opportunities exist in rocks from pre-Cambrian through the Mesozoic. The Mesozoic part in the Sverdrup Basin has been the focus of most activity where considerable success has been achieved. Twenty years of exploration in the region, including the drilling of 161 wells, has resulted in the discovery of 15 gas fields, including 2 and possible 3 in the giant gas field category. Total reserves are estimated to range between 13 and 15 TCF.

A multitude of possible trapping styles are recognized in the region. They include regional stratigraphic traps on the flanks of basement highs; carbonate fronts, associated facies changes with evaporatic sequences; and a variety of structural features. The main focus of exploratory effort in the Sverdrup Basin has been for hydrocarbons trapped in anticlinal or domal structures. Most are the result of an upward movement of salt which occurred both during sandstone deposition and later folding. Many of these structures were subsequently enhanced as the result of the Eurekan Orogeny with greatest compression in the eastern part of the Sverdrup Basin where higher amplitude structures are present. These pass gradually to broad anticlines and low amplitude structures in the west.

Estimates of the gas resources of the Arctic Islands were prepared by examination of 28 exploration plays. The average expectation of gas potential for the region is estimated to be 87 TCF with a more speculative value of 138 TCF. Values include a discovered reserve of between 13 and 15 TCF.

Current discoveries and future potential in the Arctic Island Region face special problems in terms of development. Although two major fields are located partially on-shore, most of the significant potential is thought to exist in the off-shore region. Exploration is currently conducted from ice islands but any ultimate production will reuire the development of special sea bottom facilites that will be able to cope with permanent or moving ice at the surface. Pipelining between islands, seasonal tankage, ice breaking tankers and transportation from this geographically remote area will probably delay development for many years.

EAST COAST REGION

This region extends from the Scotia Shelf into the Baffin Bay Basin. More than 170 exploratory wells have been drilled since 1966 resulting in the recognition of a major gas province near Sable Island including the Venture discovery, the currently exciting oil province surrounding Hibernia; and a narrow dominantly gas province extending up the coast of Labrador probably into Baffin Bay. Estimates of potential are based on the analysis of 32 plays, primarily in the sedimentary wedge of Tertiary and Mesozic age. Important trap types include salt cored diapiric features, large roll over anticlines against faults, block faults with overlying and flanking sands, as well as a multitude of stratigraphic traps including carbonate and clastic pinch outs.

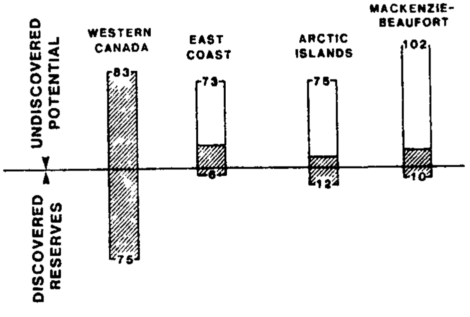
The average expectation of gas potential for this region is 72 TCF, with a speculative value of 125 TCF. These values include reserves of approximately 6 TCF which exist in more than 12 discoveries the most notable of which includes Venture which is currently acknowledged to have a reserve of greater than 1.0 TCF and Bjarni of similar magnitude.

Gas along the Labrador shelf is expected to occur in relatively deep water in an area where icebergs constitute a serious hazard. These factors may require special and probably expensive production facilities able to disconnect and move out of the way of icebergs. Potential in the Scotia Shelf Region on the other hand will probably be able to proceed with relatively normal, albeit expensive, off-shore completions with pipeline to market.

SUMMARY

In summary the Geological Survey of Canada estimates that there is a large gas potential in four regions. Figure 2 summarizes the resource estimates using the average expectation values. The portion of the bar below the line represents

GAS RESOURCES (TCF)



remaining reserves or discovered resources in frontier areas. The bar above the horizontal line represents undiscovered potential. The shaded component of both parts of the bar represents that portion of the resource considered to exist in commercially producible fields according to recent EMR studies. Considering the logistical difficulties that exist in most of the frontier regions it is probably safe to say that the potential in Western Canada is the least expensive and most readily available resource. Discoveries on the Scotia Shelf represent the next opportunity for development, probably in the very near future. Resources located in the remaining frontier regions will probably have to be deferred until improved technology and better price/market situations exist.

COMMERCIALIZATION OF INSTITUTIONAL R&D: THE GRI APPROACH

THOMAS L. MORAN, DIRECTOR, TECHNOLOGY APPLICATIONS
JAMES E. DREWRY, VICE PRESIDENT,
TECHNOLOGY ASSESSMENT & APPLICATIONS

GAS RESEARCH INSTITUTE

Gas Research Institute (GRI) is an independent not-for-profit research organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the regulated gas industry and its customers. GRI contracts individual elements of its overall program to leading R&D organizations in the form of specific results-oriented projects. The only exceptions to this rule are certain in-house technical and economic assessments and analyses. GRI is currently managing 301 R&D contracts including 152 contractors.

The benefits of our program are available to the gas industry and its customers only if the results of the individual projects are commercialized. GRI regards commercialization as the process by which the results of a research and development program are introduced and accepted by end user markets. Since this occurs after the completion of the R&D program, GRI is not involved. However, there is much GRI can do in the course of planning and executing the R&D that will affect the commercialization potential of a given concept. In practice, commercialization takes many forms and paths depending on the technology and its potential applications. In the case of hardware-oriented programs typical of GRI's Efficient Utilization research program, there is generally an end product involved, be it a home heating furnace or a ladle preheater. In the case of technology development-oriented programs, the need exists to transfer the technology to those areas of application where it can be used to best advantage. The following few examples will illustrate the experience GRI has had in its Efficient Utilization and Enhanced Service program areas.

The Efficient Utilization R&D Program is divided into Industrial and Residential/Commercial subprogram areas. As one would suspect, there are many differences in these areas that bear directly on the process of new product development and introduction.

In the industrial area a number of manufacturers have internal applied research and product development capability. Also, the larger manufacturing companies maintain separate R&D Divisions that are charged with corporate, as well as external, contract research responsibilities. Recently there has been a trend towards locating new business development functions within the corporate R&D structure. Essentially, as new products are developed, they enter a venture period under the sponsorship of the development team. This provides a valuable opportunity to test market and refine the design of pre-production prototypes before they are assigned to an operating division within the parent company. The upshot of this trend is that many industrial firms now have an identified corporate commitment to develop, venture, and commercialize new products. Again, since GRI participates only in the R&D effort, we view this trend by private industry as a positive force in bringing novel products and processes to the marketplace.

An example of this concept is the ladle preheater which was developed by the Cadre Corporation and now marketed by the corporation's Thermecon Division. The system features a ceramic fiber sealing surface that is pressed against the ladle mouth. Once the ladle is sealed it becomes part of a recuperated combustion system and is transformed into a small and highly efficient furnace within which the ladle lining materials are uniformly preheated. This project is unique in the integrated nature of the development and commercialization team. The same key personnel who were responsible for the development effort also launched the resulting business unit which is charged with product introduction and market penetration. To date, the results have been excellent with over 30 systems sold. In follow-on activities, the technology is in the process of being licensed into foreign markets, and a spin-off concept is currently under development that targets the smaller ladles commonly found in the foundry industry.

Turning to the residential/commercial area, GRI's major success to date has been the pulse combustion furnace. In this example we find a totally different commercialization path. In 1962 the A.G.A. Laboratories (A.G.A.L.) began working on the basic design of a small pulse combustion burner. Over a period of several years, A.G.A.L. produced a series of design and operating improvements to the basic pulse combustion burner and demonstrated its feasibility for several applications. In 1976 the basic ideas for the pulse combustion furnace concept were first presented to a group of gas furnace manufacturers to solicit interest and cooperation relative to further development of the concept into a marketable product. Lennox Industries Inc. was the only furnace manufacturer to show any significant interest in the novel pulse combustion furnace concept at that particular stage of its development and agreed to commence working cooperatively with A.G.A.L. on a limited basis.

In 1977 GRI assumed funding and management responsibility for the pulse combustion furnace project. After carefully reviewing the status and proposed R&D work plan for the continued development of the pulse combustion furnace, GRI decided to continue support for the project and took steps to establish a more coordinated and cooperative R&D effort between A.G.A.L. and Lennox to maximize the potential for achieving commercial success. In pursuing the further development and commercialization of the pulse combustion forced-air furnace, two major obstacles had to be overcome: reducing the unit's size to existing furnace dimensions and configurations and reducing the noise generated by the pulse combustion process. For any new high efficiency furnace to make a sizeable impact upon the market and effect widespread energy savings, it would have to be acceptable to the furnace replacement market. With GRI's support and overall program management, A.G.A.L. and Lennox successfully overcame the two major obstacles through several design improvements that were tested and verified in laboratory prototype units, followed by a successful 10-unit field test that was planned and conducted during the 1979-80 heating season with the support of GRI and nine of its member gas utility companies. Data was carefully compiled from the operation of a conventional furnace and a pulse combustion furnace located side by side and each operating on alternate weeks. Results showed that the pulse combustion furnaces consumed significantly less natural gas than the conventional furnaces sitting next to them.

In 1981, after additional field testing by Lennox (without GRI support), the new pulse combustion furnace, which represented the first major design change in gas furnaces during the past forty years, was unveiled. To date, tens of thousands of these units have been manufactured and sold. In retrospect, the key to success was the selection and management of a team development and commercialization effort. The commercialization partner's input to the research effort while GRI was involved was key to the commercial success of the resulting product once the R&D was complete and GRI's presence diminished.

The same approach has proven to be of value in the commercial cooking area in the commercialization of two new and highly efficient devices. These are the snorkel convection oven and the infrared deep fat fryer now being manufactured by the Vulcan-Hart Corporation. Both of these products grew out of GRI's Commercial Appliances project area. In these cases, essentially the same path was taken by GRI to solicit interest in the development work being pursued at the time by AGA Laboratories. Again, the resulting effort produced excellent results. To date, the oven continues to sell well, featuring a gas use less than 60% of the gas used by conventional ovens. In the case of the deep fat fryer, the unit has supported a market penetration unprecedented in the commercial cooking field. Again, while the exact numbers are proprietary, several thousands of these units were sold and installed within the first year of the unit's introduction. Clearly, these examples show the value of teaming the best development and commercialization partners in order to successfully introduce new products.

The last example is a case of technology transfer involving research supported by GRI at the Battelle-Columbus Laboratories. The thrust of the program is to improve quality control in the installation of new plastic pipe and is part of GRI's piping system design and materials project area. The impetus for this work is the reduction of maintenance costs and increased safety; the magnitude of the potential benefit is significant. Consider that in 1978, approximately 823,000 main and service leaks were repaired by the gas industry at an estimated cost of more than $165 million. Even a 10% reduction in this number will represent a significant benefit to the gas industry and its customers. The work thus far has focused on the development of tests to: 1) qualify plastic pipe for gas service, and 2) to predict the long-term performance of plastic gas piping systems existing in underground service. Thus far an environmental stress crack resistance (ESCR) test has been developed along with procedures to examine the effects of extrusion-induced residual stress, and a slow crack growth (SCG) test, and rapid crack propagation (RCP) studies.

In order to insure the transfer of this technology directly to the gas distribution industry, GRI has implemented a mutually complementary series of steps. First of all, a quarterly news letter is published and given general distribution within the industry under the title of Plastic Pipe Line. Success to date is evidenced by the fact that a number of gas utilities have adopted the GRI sponsored tests to verify the quality of plastic pipe prior to its installation. GRI will continue to disseminate the results of the work. In summary, the work performed by Battelle has provided our industry with a technology resource that would be clearly beyond the scope of any one of our member companies. In maintaining this capability, GRI is acting not only as the sponsor of the research effort, but also as the primary technology transfer conduit.

GRI has reorganized, forming the Technology Assessment and Applications Division. It is the stated mission of this group to support both the Research and Development Division and the Contracts and Administration Divisions, and GRI contractors in their efforts to develop and commercialize innovative gas-fired equipment and processes. The division is organized into two departments: The Center for Energy Systems Analysis, and Technology Applications. The Center for Energy Systems Analysis provides both economic and technology assessment services, while the Technology Applications department acts to provide outreach services to both the gas industry and its customers. The objective is to more clearly define the economic, business, and market related factors that produce "market-pull" and to assess the probability of commercial success before GRI enters into a given research and development program. During the course of a program, technical progress is reviewed and compared to the identified market needs and the capabilities of competing technologies. Thus, GRI has established an internal capability by which a given concept's technical and commercial merit comes under reasonable and timely review. The goal is to provide the gas industry and its customers the maximum possible degree of assurance that its R&D function will continue to be effective in providing timely and meaningful benefits.

A SYSTEMATIC APPROACH TO COMMERCIALIZATION DECISIONS

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MULTIPARTY COMMERCIALIZATION ANALYSIS

With the rising energy costs over the past decade, there has been widespread interest in bringing new generation, distribution, and storage technologies to the marketplace. To increase the chances of success in commercializing new energy technologies, an approach to analyzing alternative commercialization strategies has been developed through several applications for the Electric Power Research Institute [1,2,3,4,5], the federal government [6, 7,8], and private sector vendor organizations [9].

The commercial potential of a new technology can be evaluated from a variety of perspectives as the hierarchy outlined in Figure 1 shows. Traditional cost-benefit analysis is at the top of the hierarchy. With cost-benefit analysis, overall benefits are weighed against the costs and a tentative assessment can be made as to whether a potentially worthwhile market exists for the technology. Generally, such an analysis will be done at a societal level with no distinction made between who receives benefits and costs and who bears any risks involved. In this discussion, I will assume that the technology being considered has already passed a cost-benefit test.

Cost-benefit analysis is appropriate when a technology is relatively far from commercial application--say ten or more years--and is a useful screening tool. However, as the technology comes closer to commercial application, we have to become more concerned with the distribution of costs, benefits, and risks among the multiple parties involved with the technology. For a new technology to be commercialized requires separate decisions by many interacting parties who will be motivated to utilize the technology or to support its utilization only if the technology is attractive from their individual points of view. The purpose of multiparty commercialization analysis in the second level of Figure 1 is to provide a means of evaluating in consistent terms the impact of various commercialization strategies on each party. In this way, it is possible to pinpoint early the key incentives and impediments to commercialization. From these insights, strategies can be designed to maximize the chances for successful commercialization.

The commercialization strategies provide an outline for, but are still one step removed from, the business plans that must come from the business strategy analysis at the bottom of the hierarchy in Figure 1. Business strategy analyses are more specific and provide the basis for the detailed negotiation of contracts and for making business commitments.

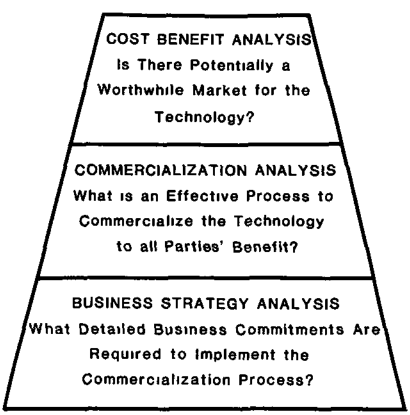

Figure 1. Multiparty Commercialization--One of Several Approaches to the Analysis of a New Technology

In the following subsections, I will describe multiparty commercialization analysis qualitatively by outlining key steps in the process:

1. Identify the key actors and their motivations.
2. Understand how the parties interact.
3. Find the leading-edge markets.
4. Evaluate the impact of uncertainty.
5. Determine the most effective strategy for getting the technology to the markets.

In describing these steps, I will emphasize insights and patterns observed in previous applications rather than analytic rigor.

IDENTIFY THE KEY ACTORS

Today many parties are involved in successfully commercializing a new technology. The model of a market in which a producer can simply take a good idea to the customer at a reasonable price and see the sales roll in is rarely applicable. The development, demonstration, and commercialization of a new technology is not the result of a single decision; it is the result of a series of interacting decisions made by many different parties in response to diverse incentives. Consequently, to commercialize a new technology successfully, one must consider the viewpoints of all the key participants. Table 1 identifies the parties who are typically important. Commercialization will have an impact on the bottom-line of each of the parties. For the process to have the best chance for success, each party should see some advantage. Every party that does not see an improvement, represents a potential impediment to commercialization.

Table 1. Important Parties in Commercializing New Energy Technologies

- Technology Suppliers
- Technology Users
  - Regulated Energy Suppliers (e.g., electric utilities)
  - Unregulated Energy Suppliers (e.g., PURPA generators)
  - End Users (e.g., homeowners)
- Regulatory Agencies
- State and Federal Governments
- Interested Third Parties
  - Research Institutes (e.g., Electric Power Research Institute or Gas Research Institute)
  - Advocacy Groups (e.g., Environmental Defense Fund)

UNDERSTAND HOW THE PARTIES INTERACT

A key step in multiparty commercialization analysis is to construct a model that explicitly represents the interactions among the key parties. An outline of such a model appropriate for technologies intended for the regulated electric utility market is shown in Figure 2. The model is a summary of how the parties make the decisions that could lead to the transition from advanced development to a commercially available option. At a minimum it represents the following:

1. The environment of commercialization (e.g., energy demand, available technologies, and fuel prices).

2. Supplier decision making (e.g., investment and operating decisions).

3. User decision making (e. g., investment and operating decisions).

4. Institutional factors (e.g., government programs, tax treatment, third-party activities, and regulations).

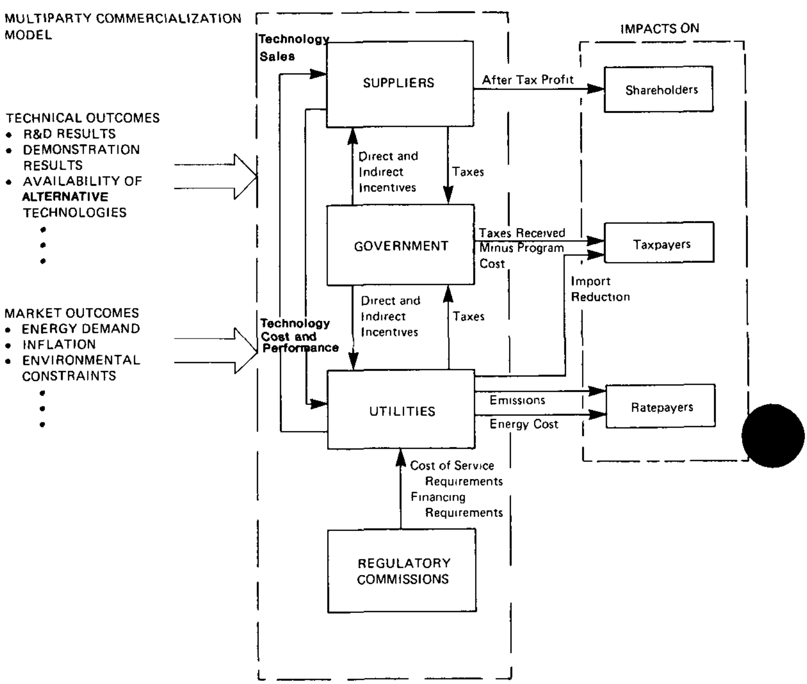

Figure 2. Outline of Multiparty Commercialization Model

By integrating each of these factors one can develop an explicit understanding of the impact on each party's bottom-line of supporting the technology.

Using the multiparty commercialization model, a new technology can be evaluated as it would be seen by each of the key parties. For example, suppose there is a technology whose key advantage is reduced fuel burn. Such a technology might well present a good profit opportunity when evaluated by potential vendors and a good opportunity for reducing costs to customers when evaluated by utilities. On the surface it would appear to be a sure "winner." However, the regulatory environment in which many utilities currently operate will significantly reduce their interest. To invest in the new technology, they are faced with what will likely be a lengthy process to obtain approval after which they may well be allowed a rate of return on their investment below their market cost of capital. On the other hand, if they continue to use the older, less efficient technology, they may well have a fuel adjustment clause that allows the higher fuel costs to be passed through, and they are not faced with the problem of investing under adverse conditions.

This example illustrates that the evaluation of the commercial potential of a new energy technology requires a detailed understanding of how all the parties in the marketplace interact.

FIND THE LEADING EDGE MARKETS

Whether a technology will ultimately be successfully commercialized depends on the potential market for the technology and on the institutional conditions that govern how decisions are made in the market. The importance of market potential is borne out by numerous studies [10,11, 12,13,14] that recognize the greater importance of the market's "pull" over the technology's "push" in determining commercialization success. In other words, it is dangerous to promote a technology without paying sufficient attention on a party-by-party basis to the ultimate markets in which it might eventually be used.

The multiparty commercialization model discussed in the last subsection provides an important tool for identifying the market for the technology. The model is by definition an explicit description of the balancing of supply and demand in the marketplace for the technology. It can be thought of as a vehicle for translating sets of assumptions describing the commercialization environment, the energy market, and available technologies into sales projections for the technology being evaluated. Figure 3 represents the output of such a model used to assess the market potential of utility storage technologies [2,15]. In this case, the projections are for sales of compressed air energy storage (CAES) systems. Projections such as those in Figure 3 can be used to identify specific regions and systems where early sales are most likely to occur and thus serve to help guide commercialization efforts.

Generally, commercialization will proceed most readily in a heterogeneous market with some users for whom the technology has an especially high value. These users can be the targets for early installations that start commercialization process. Thus, projections such as Figure 3 can be used to identify potential targets for early sales. As another example, consider large wind energy conversion systems (WECS) that may play a role in the future for many electric utilities. However, WECS may have a special value to some of those utilities operating solely in a fuel-saving mode to replace expensive oil consumption [6]. If these applications are successful, they may provide the operating experience and information necessary for WECS to be used in other operating modes where they replace or defer the need for conventional generating capacity.

In evaluating commercialization decisions, it is important to separate the high value target market, which represents the potential early installations, and the mature markets, which include the lower value, longer-term applications. The leading edge market is needed to start the commercialization process. The mature market is necessary to sustain the technology.

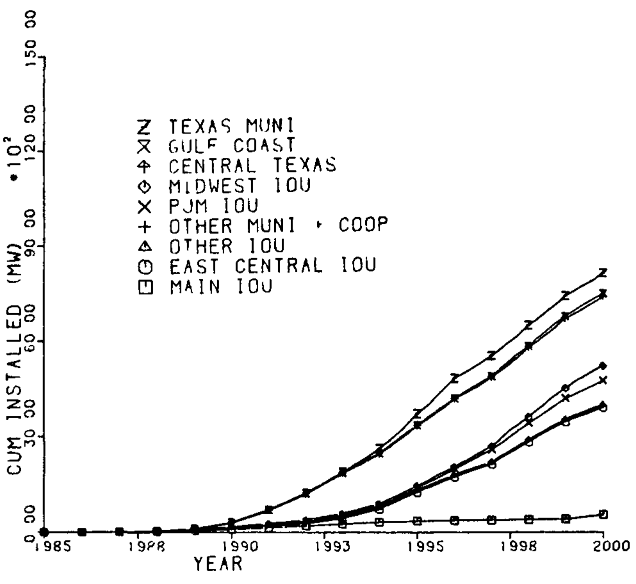

Figure 3. Cumulative CAES Installations by Market Nominal Scenario

EVALUATE THE IMPACT OF UNCERTAINTY

Uncertainty confounds the commercialization process at every turn. The technical uncertainty in factors such as the technology's cost and performance and in the potential availability of alternative technologies compounds with uncertainty in market variables such as demand and inflation. Since the way these uncertainties affect each of the involved parties can have a determining effect on commercialization, it is essential that the commercialization analysis takes them into account. For example, consider the impact of current regulatory treatment of new technologies that might be adopted by electric utilities. The cost and performance of any new technology is uncertain before adoption occurs. As Figure 4 shows, the typical technology offers an improvement on the average, but some risk exists that it will not be any better than the current alternative. How will the adoption of such a technology be viewed by electric utilities under current regulations?

If the cost of producing energy with the new technology is greater than the cost of producing energy with the currently available alternative technology, utilities perceive a significant risk that investments in the new technology will be ruled imprudent and the associated costs will be wholly or partially uncollected from their customers. Hence the utility shareholders bear the downside risk of adopting the technology. If the new technology's cost is less than the alternative, then the reduced costs reduce customer bills rather than increasing the rate of return allowed to the shareholders. The situation can be outlined diagramatically as Figure 5 shows. From the point of view of utility ratepayers, the new technology might offer a significant improvement on an expected value basis. However, the risk exposure of the utility shareholders is often such that the reward for investing in the technology is limited at best.

As an example of the impact of different underlying institutional conditions, it is interestng to compare the situation under current regulatory conditions with what might happen if the new technology were to be adopted by third-party generators. A third-party generator is a nonregulated firm or collection of firms that generate electricity to sell to an electric utility. If the technology used is small enough, then under current Public Utility Regulatory Policy Act (PURPA) conditions, the utility must purchase the technology at the avoided cost, that is, the cost of the utility's alternative source of electric power. For the sake of comparison, suppose that the distribution of cost for the new technology is the same as before. Since the third-party generator is unregulated, no upper bound exists on the return its shareholders may make. The return to the third-party shareholders is directly proportional to the cost savings they can achieve with the new

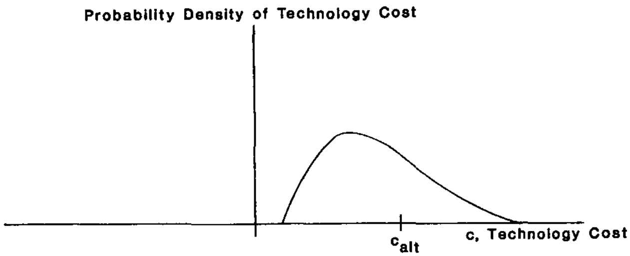

Figure 4. Typical Probability Density Function of Cost for a New Technology

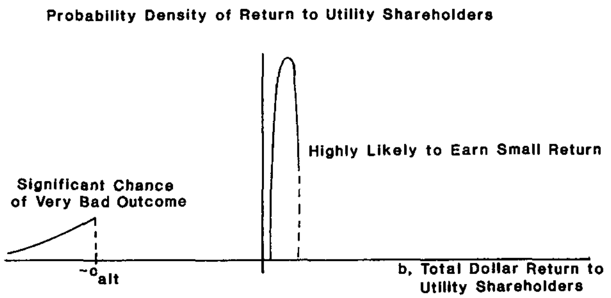

Figure 5. Probability Density of Return to Utility Shareholders Under Current Regulatory Conditions

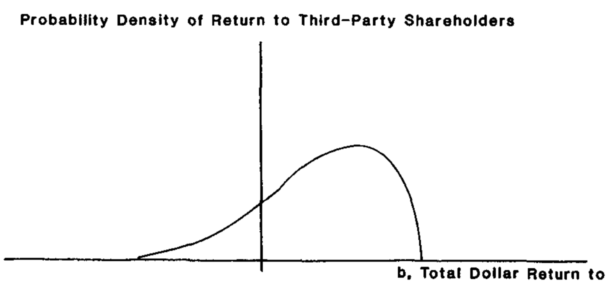

Figure 6. Probability Density of Return to Third-Party Shareholders

technology. Figure 6 shows how the distribution on cost is translated into a distribution on return to third-party shareholders. Note, in contrast to the business-as-usual case, a substantial chance exists of large positive benefits. Although there is some chance of loss also, the overall distribution on profits appears attractive.

The implications of explicitly accounting for uncertainty are powerful. First, uncertainty and the exposure to risk that it causes different parties can be a stopper for a technology that in a deterministic evaluation appears to be a sure winner. Second, a technology that has rough sledding gaining acceptance under one set of conditions may be quite attractive under other institutional conditions.

DETERMINE THE MOST EFFECTIVE STRATEGY FOR GETTING THE TECHNOLOGY TO THE MARKET

The institutional relationships that exist among all the parties in the market are as important as the existence of that market. By institutional relationships, I mean the sum total of laws, ways of doing business, and so on that determine how decisions are made regarding the production and utilization of new technologies. A particular set of relationships can be thought of as a commercialization strategy. The commercialization strategy determines the benefits perceived by each party. It translates a perception of the technology's cost and performance into a statement of benefits for each party.

Strategies for commercialization range from a passive approach to the market, following business-as-usual, to an active approach where the commercialization environment is changed by creating new institutions. The commercialization strategy chosen depends on the degree to which the parties involved are able to influence the commercialization environment. Table 2 summarizes a number of traditional and proposed approaches and shows how benefits, costs, and risks are shared in the marketplace under alternative commercialization strategies for technologies used by regulated utilities.

In Table 2, the columns correspond to the key parties potentially involved in commercializing new technologies, while the rows are simplified descriptions of different institutional arrangements that might be in effect during the commercialization process. In these simplified summaries, the critical issue is the division of benefits and risks among the key parties. For example, the first row represents business-as-usual under current regulatory treatment of risky technologies as I have already summarized.

The remaining rows of Table 2 correspond to different mechanisms for sharing the benefits and costs of new

Table 2. Simplified Characterizations of Selected Commercialization Strategies

	Utility Shareholders	Utility Ratepayers	Taxpayers	Vendor Shareholders	Third-Party Generator Shareholders
Business-As-Usual	Bear Risk on Downside & "Normal" Return on Upside	Receive Benefits of Utilizing Technology		"Cost-Plus" Operating Environment	
Utility Consortium	Share Downside Risk & "Normal" Return on Upside	Receive Benefits of Utilizing Technology		"Cost-Plus" Operating Environment	
All-Events Tariff	"Normal" Return	Receive Benefits and Bear all Risk		"Cost-Plus" Operating Environment	
Supplier Guarantee	"Normal" Return	Receive Benefits of Utilizing Technology		Bear at Least Part of Risk	
Loan Guarantee	"Normal" Return	Receive Benefits of Utilizing Technology	Bear Risk	"Cost-Plus" Operating Environment	
Third-Party Generation (PURPA)		Maintain Status Quo Costs		"Cost-Plus" Operating Environment	Bear Risk on Downside and Attractive Profit on Upside

technologies. For example, as the second row indicates, a consortium of utilities can be established to construct a plant and thus spread the down-side risk exposure of any particular utility's shareholders. This approach was used in the early commercialization of nuclear reactors and continues to be used today for the acquisition of capital intensive facilities.

The third row of Table 2 represents an example where risk is shifted from utility shareholders to utility ratepayers. An all-events tariff, whereby costs can be recovered whether or not the plant produces energy in a commercially viable manner, shifts the risk of new technologies to utility ratepayers. For example, such schemes have been discussed as regulatory treatment of commercial demonstration synthetic gas plants [16].

The fourth row of Table 2 corresponds to supplier shareholders bearing all or part of the risk of a new technology through some form of guarantee. Because of the complexities of new technologies and the uncertain impacts of regulatory actions, suppliers of new technologies are currently adverse to selling early units on a normal warranty basis [17]; that is on the basis of a fixed price with a guaranteed performance. Instead, they are willing to build plants only when they are reimbursed for the actual costs required to deliver a unit. In some cases, however, a rationale exists for the supplier shareholders to pick up some of the risk, particularly as a mechanism for reducing the perceived risk in using a well-developed, but not commercialized technology. Reference [1] provides an example involving advanced load-leveling batteries where such supplier risk sharing would be logical if current development objectives are met.

The loan guarantee in the next row of Table 2 provides a mechanism for shifting the risk to taxpayers by indemnifying the participants in a risky project against the consequences of project failure. The funds to finance the installation are obtained with a provision that in the event of a default on the loan, it will be assumed by the government. This incentive has been used to try to stimulate the development of oil shale resources.

In the final row of Table 2, third-party generation is given as an example of shifting the risk exposure to the shareholders of a nonregulated generating entity.

Table 2 is meant to be illustrative. It clearly does not exhaust the alternative institutional arrangements that might be pursued to commercialize a new technology. Much current attention is being devoted to such arrangements, as evidenced by the spate of recent articles in Public Utilities Fortnightly [16,17,18,19] dealing with ideas for better matching the risks and rewards of utilizing both new and capital intensive technologies to all parties' satisfaction.

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"THE REALITIES OF TAKING ENERGY TECHNOLOGIES TO MARKET"

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Purpose: To present by example and commentary the General Electric approach to technology transfer and commercialization;

To reinforce the point that technology advancement will help solve the energy and economic problems of electrical power generation, transmission and distribution;

To demonstrate that the process of transfer and commercialization is not an easy, systematized formula ... rather that it is expensive, hard work, requiring the time and cooperation of all key functions in the process.

This session of ET '83 -- "Practical Approaches to Technology Transfer and Commercialization" -- offers us the opportunity to take a hard look at the realities of bringing technologies that work to the marketplace.

I say "Technologies That Work," because there are many technological developments that break new ground ... but don't work in the market. They fail to be truly responsive to today's -- and tomorrow's -- needs.

At General Electric, market practicality drives R&D ... because our business success depends on the ability to provide products our customers need. If we don't do a good job of commercializing our technologies ... we could invent our way into oblivion.

Throughout our more than one hundred year history, we have, of course, invented and developed many technologies that moved successfully into the real world. Some of these originated in our business operations, where about 90% of our technical people are employed. But much new technology is generated at our Corporate Research and Development Center, where the emphasis is on longer time horizons and on more fundamental and generic work. Whether technology originates in the Corporate Lab or in Operations, the vital factor is linking it to the marketplace. Only then is basic understanding converted to innovations that serve the needs of people.

The link to the marketplace starts at the beginning of the R&D process when projects are selected.

At any time there are many creative ideas bubbling up from the working level of the R&D organization. Which should be followed up and which should be put aside? Which should receive massive resources, and which should be allowed to mature at a leisurely pace away from the glare of top management attention?

The choices are never simple. They are made correctly only when people at all levels in the management chain understand how R&D decisions are tied to business strategy.

The product time horizon may be near or it may be far, but successful R&D choices are always those made with a clear vision of how the R&D results will eventually come together with market needs.

The next phase of R&D is to carry out the work. The key element here is having the right technical capabilities already in place, or built up on a time scale compatible with project needs.

Particularly for work at the leading edge of technology, we have found that expertise in key generic areas that we know are of intrinsic importance to the Company cannot be built up overnight. Heat transfer, combustion, microelectronics, computer science, materials -- these are examples of areas that are important to many of our product lines. We have to maintain -- over a long period of time -- an on-going state-of-the-art competence in these fields.

But what about the link to the marketplace as we carry out the development work? Do we just stand back and wait for the technology work to be finished before we start to think of its place in the market? The answer, of course, is, "No."

There has to be a deep sense of entrepreneurial zeal on the part of the research people to see their invention shaped in such a way that it will be a market success. Of equal importance is a parallel commitment and sense of ownership by the relevant Company business. That means that the operating components must be involved early in the project in a very direct way.

You just cannot develop a product in the laboratory, hand it to operations on a silver platter, and expect to see commercial success. That's not the way the real world works.

This then takes us to the last phase of development, which is actually bringing a product to market. The technical know-how has to be moved from the laboratory to the factory floor. Engineering, manufacturing, marketing and financial skills and resources have to be put in place.

We have found that if the right choices have been made early on, and if the development has been carried out in such a way that a real business commitment exists, then this last phase is not a problem.
If we have the right technology for the right market, we can move into the marketplace with assurance of success.

Now, I would like to cover some successful examples of our process at work in power systems technology.

Several years ago, our scientists and engineers working in the area of microprocessor and communications technology joined with the Electric Power Research Institute in projects on substation automation. The objective: develop automated systems for utility transmission and distribution substations that minimize the disruptions caused by system faults ... automate many of the functions performed in substations ... and reduce operating costs through optimized performance.

With the breakthroughs in the world of microprocessors, new opportunities for fault location, damage assessment and rapid restoration of power have become economically attractive. These can achieve reduced outage times and lower costs for power system maintenance.

The key to these programs is the use of distributed microprocessors in the power system: on the grid to provide information ... in the substation for data acquisition, monitoring, protection and control ... and in the dispatch centers for coordination and integration between substations. Key decisions are automatically made and carried out at the level where the information is available and reported to the higher level for integration and coordination.

Utilities can now utilize existing facilities better ... optimize operations and maintenance for more efficiency and lower losses ... restore customer service more rapidly after a fault ... and utilize more timely and ordered data on the system condition.

This will mean greater productivity of invested capital and system operations.

On-line experiments in Illinois, New York and Pennsylvania demonstrated the feasibility of the system, and full commercial installations are expected to be in service by 1986.

Another example: several years ago, some of our thermodynamics experts came up with an idea for an industrial heat pump system that would capture and upgrade the value of waste heat that is normally lost in process industries.

We had the basics in place: a good technology idea ... a business operation that was developing a compressor product line ... and marketing people who knew and understood the industry. The last element was *crucial*, because our *initial* evaluation of the market showed a vast potential, based on detailed analyses of the heat content in waste energy streams generated by industry.

However, thermally upgrading waste heat to a temperature range that can't be used by the producer of the waste heat, or by some nearby operation, is of little value to that producer. Those who *can* use the captured heat became our target market.

Our people who know the industry inside and out -- who have spent years working in it -- brought us back to earth and focused our efforts on the near-term economic opportunities ... the areas of immediate market need.

That criterion eliminated a significant fraction of the original market potential. But, the remaining market -- a real market -- was still very large and attractive.

Very early in the project some of our research people moved in with operations people -- in this case, our Mechanical Drive Turbine Department -- and some of their engineers moved in with the research people. A strong mutual commitment to product ownership developed, and as we progressed, we proved out the industrial heat pump system with an installation in our own plastics manufacturing operations.

The system is commercially available and the business is off and running.

Here's another example: with the EPA rulings about indoor transformers, the product that had been in use for decades became environmentally unacceptable. That didn't make the market need go away. It heightened the need by adding incentive to replace the units in service, along with supplying transformers for new installations.

The previous system relied on cooling the core and coils with an insulating fluid for heat conduction.

Heat transfer by vaporization is much more efficient than by conduction ... and our challenge here was to design an economically acceptable system that utilizes commercially available, non-flammable fluids that have the desired electrical properties ... and at the same time meets the EPA requirements.

Our research center went to work on an idea utilizing vapor cooling heat transfer technology. We developed a unique system that made the technology both environmentally acceptable and safe.

The business that took the product to market was involved in the development and technology transfer process early ... and prototype designs were built and field tested at GE plant locations.

The rest is history. GE Vapor-Tran is the most successful of the new generation transformers, with over one thousand sold since the technology has been commercially available.

The key, of course, was the right idea. But also very important was the early involvement of our Medium Transformer Department with the R&D effort. This led to an early business and R&D commitment to bring out an affordable product and give us the competitive edge which resulted in our reaching a position of product and market leadership.

Now ... an example of on-going technology development and commercialization.

The efficiency of gas turbines is a strong function of their firing temperature. The higher the temperature, the higher the efficiency. The problem with high firing temperature is survival of the turbine materials. Much progress has been made in materials that can withstand high temperatures, and also in keeping the turbine parts cool in ever hotter gas streams. But gas turbine technology is still growing -- the state-of-the-art has not reached full maturation.

Today's industrial gas turbine firing temperatures are in the range of 2000°F. Our people believe that it is possible to move in steps up to 3000°F firing temperature ... with a transition from the evolution of air-cooling technology to a revolutionary water-cooled approach.

Fuel efficiency is only one reason for water cooling. Another is multi-fuel flexibility.

The program is being conducted with the Department of Energy, whose focus is on coal-derived fuels. With the high temperature water-cooled turbine, we'll be able to burn lesser or poor quality fuel because the water will cool the turbine surfaces much below the temperatures in today's turbines. This will allow markably reduced rates of corrosion.

This technology thrust dovetails with D.O.E. objectives ... and will result in a multi-fuel, high-efficiency gas turbine that will meet coal-derived fuel objectives.

Our program centers on a phased approach, combining air and water-cooling, eventually leading to full water-cooled designs.

As these hotter firing turbines move into the marketplace, we expect to gain increasing customer acceptance of gas turbine generated power by demonstrating the economic feasibility of each successive turbine generation.

Early in the development planning, we involved the operating component, the Gas Turbine Division, in a feasibility analysis, to build their conviction in the technology ... and to enlist their support in developing the phased technology improvements that hold the key to their future success in opening up new market segments.

The gas turbine description leads me to my last example of technology transfer: our involvement in one of the most exciting new energy projects, the Integrated Coal Gasification Combined Cycle program -- I.G.C.C. -- known as "Cool Water." The project includes EPRI, Texaco, Southern California Edison, Bechtel, a Japanese Cool Water Project group ... and, of course, GE.

IGCC is one very attractive way to meet the major uncertainties of natural gas and oil prices and availability. Their unpredictability has intensified the focus on coal as the practical, affordable energy alternative for the U.S.

However, we are all aware of the environmental problems associated with coal as a power generating fuel. It is just plain dirty ... and the costs to scrub the emissions are high.

Gasification is generally considered to be the emerging technology that will allow us to capitalize best on our coal reserves. This process produces a gas that can be readily cleaned with conventional techniques to meet all environmental standards. This gas, then, is the fuel that can be used to feed a highly efficient Combined-Cycle generating plant.

In 1978, EPRI and SoCal Edison took the initiative to form a consortium to develop and demonstrate the commercial scale feasibility of coal gasification and combined cycle power generation in the 100 Megawatt range.

Our involvement in the program includes:

- -- initial analytic and experimental studies from our R&D center, which went a long way toward establishing the feasibility of the large-scale IGCC concept
- -- Combined-Cycle technology with a 65 Megawatt gas turbine and a steam turbine, rated at an additional 56 Megawatts
- -- and the overall thermal systems design of the plant

Our key technology challenge in the project is to design and prove the control system that will make the integration of gasification and Combined-Cycle work reliably on the 100 Megawatt scale.

The project is well under way, at the power plant site under construction near Daggett, California. The first BTU generation is expected about mid-1984. That will kick off a six and a half year demonstration of the commercial practicality of the large scale system. And ... it's a good example of the time needed to move even a promising and major technology to market.

The IGCC project targets greater efficiency, lowered emission levels, low capital investment, shorter installation cycles and low inherent water consumption as the main advantage objectives for the developing technology.

Not coincidentally, we can envision our High Temperature Gas Turbine with its multi-fuel capability eventually moving into the Cool Water project, to enhance the overall efficiency of the system.

Here, the IGCC idea -- marrying the country's largest and least expensive energy resource, coal, with the most efficient power generation system, Combined-Cycle -- is expected to be developed and proven as the most practical and commercially affordable means for U.S. utilities to meet user demand and environmental requirements well into the next century.

I have highlighted projects that involve a lot of hard work by all levels of the Company. These efforts are backed by the confidence and commitment of resources that come from a long, successful history of finding, developing and honing technologies that work in the markets we serve. Some meet today's needs ... while others will provide future answers ... and some may not work at all.

In my view, the principles for technology commercialization are unabashed and simple:

-- Pick technologies to work on that match the Company's business strategy. In particular there must be a market for the technology ... either one that exists, or one that can be developed, once technology has been brought to an affordable, practical level. Furthermore, the technology should give real commercial leverage, a lead over the competition, when it is introduced.

-- Develop the technology with the best technical resources available. That usually means having people in place who are first rate in critical technologies. Do not lose sight of the market while developing the technology, but rather build the links from the laboratory to commercial operations from the inception of development work.

-- Put in place the resources to bring the technology successfully to market -- resources in manufacturing, engineering, financial skills, and so on.

To achieve success, couple research scientists and engineers with operating components' experience and knowledge of their markets to drive toward commercial practicality.

There's no real option in this process. Take a simple, hard-nosed approach to technology commercialization ... and support it with tough, hard, market-directed work.

Research in splendid isolation just doesn't work.

DETERMINING THE EFFECT OF ENERGY EFFICIENT APPLIANCES ON UTILITY RESIDENTIAL DEMAND

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0. ABSTRACT

Studies have indicated that the use of Energy Efficient Appliances (EEA's) can reduce residential energy consumption by up to 30%. However, there are no reliable estimates regarding their effect on the residential demand experienced by electric utilities. In the context of a fluctuating economic and regulatory environment and increasing penetration levels of EEA's, this issue becomes more significant.

Current research efforts are aimed at developing models of household energy consumption and demand to provide consumers with a means of evaluating energy conservation alternatives. These models which incorporate EEA's, can be easily extended to reproduce results obtained from bus load aggregation models. This can be used to study the effect of increasing penetration levels of EEA's on utility demand. This approach to end-use demand forecasting provides an alternative modelling philosophy to current models in use and is expected to increase model fidelity and accuracy. Further, it yields models which are of use to both the consumer and the utility.

This paper discusses the household models under development and their extension for aggregation.

1.0 INTRODUCTION

The current emphasis on energy conservation has resulted in a rapidly expanding market for Energy Efficient Appliances (EEA's). For the purpose of this paper (and the underlying research efforts) the term EEA is taken to include all appliances which through improved design and/or addition of alternative technology devices (heat pumps, solar units, photovoltaics, etc.) reduce electric energy consumption. Thus EEA's would include variable air volume handlers, energy efficient motors, solar assisted water heaters, heat pumps, etc.

The efficacy of EEA's has been clearly demonstrated in several studies, conducted recently. These studies indicate that residential energy consumption can be reduced by as much as 30% by the use of EEA's [1]. However, the major concern of electric utilities is the demand reduction that can be obtained from an increasing market penetration of such appliances. In an ever changing regulatory and economic environment, electric utilities need reliable estimates of possible reductions in demand through the use of EEA's.

However, any such estimate necessarily depends on the penetration levels of EEA's. These, in turn, depend on consumer decisions which will be dictated by the consumer's perception of the benefits accruing to him from the use of EEA's. Therefore, current research efforts are aimed at developing models of household energy consumption and demand to aid consumers in making such decisions. In addition, these models can be easily extended to estimate the effect of EEA's on utility demand by aggregation techniques.

This paper discusses the extension of household energy consumption and demand models to utility residential demand estimation, incorporating a variable penetration level of EEA's.

2.0 MODELLING A SINGLE HOUSEHOLD

The basic motivation for single household modelling lies in the perceived need for a comprehensive household energy usage model which would allow consumers to study the effect of various energy saving alternatives within the framework of various parameters such as:

i) size of dwelling;
ii) normal number of inhabitants; and
iii) usage patterns and individual habits.

Although recent interest in end-use demand forecasting has led to the development of appliance models, the concentration on utility demand forecasting has precluded household models. It is axiomatic that in a single household where several appliances function within a system boundary, interactions exist between the system elements (appliances) and their environment (including other elements). As a simple case in point, heat generated by lighting, cooking and household chores will affect the operation of space conditioning equipment through changes in the indoor ambient temperature. Thus a single household is not simply a physical juxtaposition of appliance models, but a complete system with several interactive relationships between elements. Further, it is these interrelationships and characteristic usage patterns which will affect the utility of EEA's in a household.

Additionally, in the futuristic scenario of homeostatic control [2], such detailed modelling could also become of everyday utility to homeowners.

1 MODELLING METHODOLOGY

The basic modelling approach used for household modelling emphasizes simulation and synthetic model development as opposed to the analytical approach employed for end-use demand forecasting [3,4,5,6].

The crux of the modelling approach lay in developing appliance models - conventional and energy efficient - since they are central to the problem irrespective of residence type and usage pattern.

The first step consisted of identifying the loads to be modelled. This problem was approached by dividing household functions/activities into functional classes such as food preservation, food preparation, lighting, space conditioning, laundering, etc. This division provided clear cut classes of appliance types from which some of the several appliances used for each function could be selected, based on wattage and yearly energy use. For example, Table 1 shows several appliances used in cooking functions. Obviously an average household will contain several of these appliances. But only the range has a sufficiently high wattage and yearly usage to warrant a modelling effort. The consumption of the other devices is so small on a daily basis that they can be modelled as a random component superimposed on the major appliance(s).

TABLE 1: Ratings and Est. KWH consumption of selected food preparation appliances [7].

APPLIANCE	RATING (W)	EST. KWH USED ANNUALLY
Blender	386	15
Broiler	1436	100
Coffee Maker	894	106
Frying Pan	1196	186
Hot Plate	1257	90
Range with oven	12,200	1,175
Toaster	1,146	89

Having identified the major appliances to be modelled, physically based load models were developed. The term 'physically based models' derives from the modelling considerations used - mainly the mechanical and electrical bases of the appliance [3]. This allows the inclusion of the impact of environmental factors on the appliance model. Several sources of physically based appliance models exist in the literature, [3,4,6]. However, some modifications of these models was required to introduce the extra detail sought in the household model.

Along with models of conventional appliances, physically based models of EEA's are also required for comparative purposes. This requires a determination of how they modify the energy consumption and demand pattern of conventional devices. For example, a solar assisted water heater employs a solar component to heat/preheat water. The operation of the solar component will depend on insolation and the tilt of the solar collectors, among other things. Hence, these features need to be incorporated in the water heater model to obtain the performance of a solar assisted unit. While end-use demand forecasting has led to the development of conventional appliance models, there seems to be a dearth of EEA models in the literature. Models of EEA's are therefore being developed currently.

The appliance models when interconnected yield a model of the physical household. The simulation of the household brings into play synthetic models of usage and factors such as residence type and size. The synthetic usage models being developed currently are derived from data collected from the literature and several other research efforts aimed at such data collection.

3.0 AGGREGATION OF HOUSEHOLD DEMAND

A detailed household energy consumption and elecric demand model with the capability of evaluating alternative energy conservation options has been outlined above. In order to estimate the effect of varying penetration levels of EEA's on the residential demand experienced by an electric utility, it is necessary to aggregate various households at the utility bus or feeder.

Current end-use demand forecasting techniques rely on aggregation of appliances at the bus level using either of two methodologies:

i) Gentile, et.al., [5] use load research data to determine the diversified demand of each appliance vs. the time-of-day. Utility billing data, load research data and market saturation figures are then used to determine the number of appliances of each type connected to the feeder/bus. The product of the two gives the total demand per appliance type. Then, the sum of all appliance demands yields the total residential demand vs. time-of-day.

ii) The second method [3,4] uses average parameters for physically based models and a diffusion model to derive the steady state probability that a unit is on. This essentially yields the diversified demand for an appliance and the aggregation process proceeds in the same way as the first.

This paper does not question the operating premises of either of the aggregation methodologies discussed above. Instead it is intended to offer an alternative modelling viewpoint which also adds greater fidelity to current end-use demand forecasting methodologies. Increasing model complexity carries with it the inherent danger of degrading model credibility if parameters are not estimated accurately. However, in the case of our model, the danger will be minimized because:

i) the system element interactions incorporated in the household model are dependent on appliance model parameters used in the literature and determined to be calculable from available data; and

ii) increasing amounts of analytical data are becoming available on issues such as the effect of insolation on ambient indoor temperature as determined by the glass area, effect of lighting on ambient temperature, etc.

Thus, if it is assumed that only interactions which satisfy the above two conditions are included, then model fidelity will indeed be improved. The alternative viewpoint is provided by not only aggregating household demand (instead of appliances), but also by the proposed aggregation methodology.

3.1 DESCRIPTION OF THE PROPOSED METHODOLOGY

While the proposed methodology follows the outline of current aggregation methodologies, the point of departure lies in constructing synthetic models of usage patterns instead of estimating the steady state probability that a unit is on. This method generalizes appliance models. For example, it is possible to relate the switching on probability of water heaters to hot water usage. But if the probability is intimately connected to the volume of water required and the time at which it is drawn (as it will be), then it would be simpler to model the hot water usage pattern. Similar considerations hold for food preparation appliances, laundry equipment, etc.

Thus, the aggregation process would proceed as follows:

i) Determine residence types, and percentage of total number of households connected to a feeder/bus. There are two possible classification criteria for residences. One would be to classify by size and the other by types of inhabitants. Preliminary surveys indicate that usage patterns for bachelor establishments, two member households, family residences with two working parents and one working parent will be different. Since the modelling emphasis is on usage patterns, it is proposed that inhabitant type be the primary classification criteria and residence size, the secondary criteria. The percentages and total numbers can be determined from census and utility data [5].

ii) For each residence type determine/define an 'average' unit [illegible] terms of number and types of appliances. This can also [illegible] done using load research, market saturation, consumer survey and census data.

iii) For each residence type, determine typical usage patterns for each appliance type. Although clear cut data sources do not exist for this type of data, the authors are aware of research efforts being pursued at VPI&SU and other universities and directed towards estimating appliance usage patterns. It is expected that depending on primary classification type, the usage of a device will vary with time-of-day and variations will exist within each category. However, each house is independent of the others and the usage pattern for each can be considered to be a random variable. Under those conditions, the central limit theorem can be invoked to construct a synthetic usage pattern using normally distributed random variables. A concrete example to support the above assertion is given in the next section.

iv) The average usage patterns combined with the appliance models can then be used to simulate the daily demand curve for all residences of each type and hence the residential demand at a particular bus/feeder.

It only remains now to incorporate EEA's into the modelling procedure described above. If the market saturation figures for EEA's are available, then each residence category can be divided into two subdivisions - conventional and energy efficient - according to the ratio suggested by the market saturation data. For the energy efficient groups, the modified appliance models can be used to simulate demand. If, as it is bound to occur, the effect of increasing penetration levels of EEA's is under discussion, then the ratios can be changed to reflect increasingly greater proportions of EEA's.

4.0 AN EXAMPLE OF WATER HEATING MODELLING

This section presents a brief example to illustrate the fact that since each household is an independent unit and the usage of any appliance can be considered a random variable, the aggregate pattern can be generated synthetically using the Central Limit Theorem. Use is made of a simple two element water heater model [6]. For illustrative purposes, the hot water usage pattern is assumed to be characterized by:

i) a uniform distribution with limits of 0 and 100 litres to represent the volume of water drawn at each instant of hot water demand; and

ii) an exponenial random variable with a mean of 2.0 hours to represent the mean time between hot water demands. The water heater has the following parameters:

a) Tank capacity = 302.82 litres
b) Upper Element rating = 4.5 kw
c) Lower element rating = 1.5 kw
d) Inlet cold water temperature = $10^{o}C$
e) Upper element region = 1/3 of tank.

The model assumes that the recovery (upper) element has priority over the maintenance (lower) element.

The energy efficient counterpart of the water heater is assumed to be a solar component which preheats the inlet cold water to an average of $15^{o}C$ for a working period of 8:00 am to 5:00 pm on a winter day. The maximum temperature attainable is set to $30^{o}C$. The actual inlet temperature after preheating depends on the flow rate. The results of simulating the conventional and energy efficient models are shown in Table 2 below. The results indicate an approximate 12.0% reduction in consumpton and 15.0% reduction in demand. The results, specially those pertaining to energy consumption, are conservative because of the low usage of the solar component (as a preheater alone). However, the above example illustrates the type of analyses that will be available to both utilities and homeowners.

TABLE 2: Comparison of Conventional and Solar Assisted Water Heaters

QUANTITY	CONVEN-TIONAL	SOLAR ASSISTED
Average Volume Drawn (lit.)	49.34	49.34
Average Recovery Time (hrs)	0.1914	0.1009
Average Demand (kw)	2.298	1.951
Energy Consumed (kw-hr)	33.27	29.18

Further, 100 conventional water heaters were aggregated using the methodology described above. The resulting diversified demand is shown in Fig. 1. This figure also shows the diversified demand curve presented in [5] for hot water heaters. The curves are very similar in shape. Any differences can be attributed to the model simplicity and usage pattern assumptions. Thus, synthetic usage pattern models can be easily constructed for aggregation purposes.

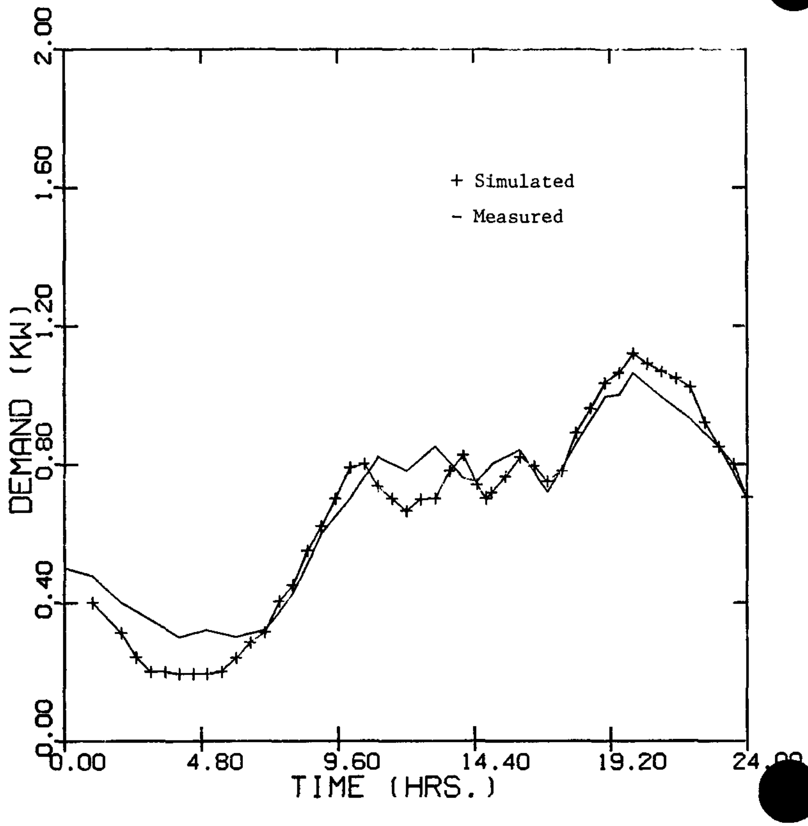

Figure 1. Water Heater Diversified Demand

5.0 CONCLUSIONS

An alternative modelling methodology for end-use demand forecasting has been developed and justified in terms of viability, accuracy and applicability. The modelling process introduces greater fidelity into end-use demand models (while minimizing the danger of model degradation) by taking into account the interactions between appliances inside a system boundary representing a household. This interactive juxtaposition of appliances creates a model of household demand/energy consumption which will allow a homeowner to evaluate his energy conservation options, as well as serve as the basic aggregation unit for estimating residential demand. Further, the aggregation methodology proposed allows the study of increasing market penetrations of Energy Efficient Appliances. It can also be used with ease for studying load management strategies and options.

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Electrotechnology & Productivity - European View

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Success in electrotechnology is all about wise use of all resources in adding useful value - which is what productivity is really about.

Your conference chairman amongst others have been making statements like 'scientists stay in their laboratories too long' or 'scientists need to respond to "market-pull" '.

If you really believe that these are the real barriers to technology transfer then that conflicts with European, and as I understand it, Japanese experience.

We well know of your advice to 'go west my boy' and note your predilection to go even further West as far as Japan rather than look back towards Europe and the East.

So let me put the record straight Phil. We believe the electric lamp was Swan's - he had the better filament.

I can assure you Ed that your European gas colleagues have also responded to the initiatives of the electric utilities. But I beg to suggest the next step in 'N' (Willie Brandt's N/S) steel industry is less likely to be gas assisted electric arcs but rather biotechnology integrated with electrochemistry. A bug to extract ferrous ions directly - you already extract ferric at Anaconda copper - then feed the ferrous into an electro-foil cell directly producing 2 metre wide strip a few microns thick. Indenting and bonding with foams and plastics can lead to a wide range of constructional materials - without the conventional vast steel making infrastructure. A good example of the results of a full system audit done with serendipity and an eye to the true needs of the market place.

But back to the main story.

We once believed the legend that the market-place was smart enough to recognise innovation and would make the necessary moves. While there may be a glimmer of truth in this view if it is a quick-money-spinning consumable, like E.T. - the other sort. But remember that the T.V. programme and film came first. Here we have a topical illustration of what we believe are the real barriers to Technology Transfer.

First, the need to create market awareness. Second, the need to familiarise both management, operator and user on how to use the innovation. The latter may be as simple as which buttons to press or as complex as changing time-honoured practices developed by great grand father who founded the company.

Kids computer games is a beautiful example of familiarisation of a future generation by the scientist entrepeneurs.

The only factor even remotely recognisable as 'market-pull" is the concept of a project champion (Sapho project Sussex Policy Research Unit, UK) amongst top management who says I wish.

The best examples I usually quote from recent time are your own Admiral Rickover and the nuclear submarine and in Europe Sir Alistair Pilkington and the Float Glass process.

In the 1960's President Sporn of your American Electric looking toward 2000 said "one cannot predict the future but we can create an electric future". He probably did not realise he was echoing a famous performance at the Bolshoi by Lenin in the early 1920's.

To that end in the late 1960's two of the European electric utilities, E de F and UK Electricity Council, set up end-use laboratories: at Renadier in France and Capenhurst in the UK.

While progress was relatively easy with lighting levels for accurate, errorless, fatigue-free performance with its implications for productivity; or with freeze or chill production line kitchens. More difficult with I.E.D. (integrated environmental design) for commercial buildings utilising the so called free heat from essential activities within the building.

Much more difficult still, to extend this concept to the individual minimum energy home.

The challenge. What you call institutional barriers, which are perhaps highest for industrial processes.

Conservation and Wise Use. Stage 1. Good housekeeping. The first 5 - 10% and not too much resistance as successful energy managers will tell you.

Stage 2. Change traditional process and building practices, but not lifestyles. The next 10 - 20%. Great resistance. Unless successful then Stage 3. Change both processes and lifestyles radically. The "energy constrained lifestyle" (Chauncey Starr, Les Arcs 1972). The game those who opt to drop out of the developing global society, both 'N' and 'S', think they are playing.

It was this challenge to technology which the NATO Science Committee asked Chauncey Starr, the project champion in the creation of EPRI, and I to address in 1971 - Note: after Hubbard but before Yamani - 120 scientists isolated at Les Arcs 1600 with no snow, no escape to the golf course or the night life only to the mountain and only then if you walked up. Sharpens the mind wonderfully.

EPRI went the traditional US route of contracting out the R & D thus taking on the responsibility of creating the market awareness. A traditional but often unrecognisable role of US Agencies since the O.N.R. German utilities, notably RWE, followed suit. We and our French colleagues set about collecting the multi-discipline R D & D (research development and demonstration) teams to burrow through the institutional and technological barriers.

Who is right? We do not know yet. But the same pattern appears in the nuclear option, probably the biggest innovation ever undertaken, yet. UK clocked up civil nuclear kWhrs faster at first. We even won the first encounter between PWR/AGR at Dungeness. Then you began to sell more and more reactors worldwide. But you could be said to have broken the rules of technology transfer: the need to adequately train operators and the local communities - an omission one would not have had from Rickover - hence T.M.I. Whether you win round 2 at Sizewell depends whether people believe the omissions have been adequately catered for. Meanwhile our French colleagues (51%) are rapidly over taking Scotland's early lead (35%) with the highest proportion of nuclear generation.

Why are the barriers to industrial wise-use apparently so high. Our experience suggests that most industrialists do not know how or where most of their energy went. Only 5% of total costs, so what! But energy is actually a much higher proportion of controllable costs. That is if you can learn how to control them - hence electro-technology.

So the first task of your multi-discipline team of scientists is to seek out what are the technical steps in particular industries - from raw materials supply to end product. Occasionally they will come upon a new product.

An energy and resource audit is called for. But you will find that those audits which E.T.S.U. (Energy Technology Support Unit) do for the UK Dept of Energy or the equivalent french groups do for CODIS - their president's top industrial strategy group - are much more thermodynamically based and searching than those expected of typical Energy Manager Services Unit for a commercial building.

So what sort of things do we achieve. I leave E d F to speak for themselves on their exhibition stand. But close by Cogema is one example, paralleled by our B.N.F.L. But that is energy production and not end-use. One of the traps for the unwary, non-global, isolationist because in the 'N' its usually much cheaper to call up another kW of capacity than to change a process to save a kW.

A good example which the UK ESI has used as the learning system to develop industrial marketing interfaces over the last decade, is electric metal melting. All good stuff:- increases useable metal yield by several percentage points by reducing metal losses, improving quality and temperature control - increases melting rates, allows rapid changes of alloy compositions melted, improves working conditions: all very good aides to productivity.

[illegible] with one of the traditional foundry materials - grey cast irons the traditional fossil melting practices did not work with electric induction. Electric was so clean that there were insufficient tramp nuclei to produce fine grain sizes. A basic R & D programme identified preferred nucleating agents. Subsequently we discovered similar work in an obscure german thesis ignored previously by foundry men as only of academic interest to their crude fuel furnaces. One had to retrain first hands, redefine prescriptions for charge materials and melting schedules.

Success was such that with real control on nucleation, tighter specifications were possible. One then needed to re-educate the design engineers to exploit the improved properties before fullest wise use of resources is achieved.

Still remaining with relatively simple seeming technolog supply and recycling of water. You will recall from othe sessions, that biotechnology calls for vast quantities of water, that extraction of shales also calls for vast water supply, that too many parts of the 'S' clear pure water is still a luxury often unobtainable. What can E.T. do? We rapidly learned that it is difficult to displace traditional biological treatment plants, nor was there a good technical case to do so - bioengineering rules O.K. But taking a total system view one can attack those factors which reduce the effectiveness (productivity in yet another sense) of such plants. First, stop at source those pollutants which damage the bacterial flora - heavy metal ions. Non-conducting fluidised bed electrolysis efficient at low concentrations - "Chemelec". Phenols, cyanides - Silent electric discharge at a 1kHz to produce ozone more efficiently. Maintain the oxygen supply throughout the whole reaction tank for aerobic digestion and at the same time conserve the exothermic heat of reaction by using deeper tanks to hold at the optimum reaction temperature of 50^{o}C - "Venturi Aeration" VO2. This latter application has taken 10 years steady progress with Welsh Water Authority before permission was granted for a full scale plant.

Post treatment to dewater the sludges to 85% solids Electrokinetics. A blend of electroosmosis draws water one way while electrophoresis draws solids the other.

To improve potability of downstream water. Ozonolysis Ozone plus an added UV photon. Most powerful oxidant known will kill bacteria and virus (typically hepatitus) and break down pyrogens, the debris of living matter,one suspected source of legionaires disease.

Electrokinetic dewatering is much more conservative in industrial processes. What at the time we believed was good example PVC still is both technically and on market-place economics.

PVC particles separated from water suspension to 85% solids for 125 kWh/tonne in plant half the capital cost of the more normal steam activated spray dryer and at less than a third the running costs. But process is held by another institutional barrier. Excess world capacity with the collapse of the market in depression of world trade.

Transfer of energy from source to work place through magnetic and electrical fields removes the limits on the rate and intensity of energy supply imposed by thermodynamics of the flame as Phil Smitt has shown you. The challenge is in effective application. So large solid three dimensional objects which require soaking eat away the advantage compared with modern insulated flame impingement furnaces of the type Ed Tob of GRI was showing you. So the classical McLouth slab heater is not the best example as we found when we tried to repeat it. By contrast continuous heat treatments of essentially two dimensional metal strip are ideal. That is if you can learn how to manipulate the Maxwell equations in a dynamic situation. It is the moving strip which makes an approximate solution attainable with the present generation of computers. That is aim for uniform spatial deposition of energy during the transit of the induction coil - this is what is called the transverse mode. Flat coils either side of the sheet with notional lines of force perpendicular to the sheet and eddy currents circulating in the plane of the sheet. The Capenhurst Davy-McKee Transverse Flux induction device actually retrofits into existing roller leveller lines for aluminium. As the control is by energy deposition rates it also demonstrates multiple feed back loop microprocessor control systems. Its a pity the production shift teams had not previously been exposed to computer games. It took 18 months of patient teaching and modifications, rather than the 6 weeks we had scheduled, to bring them to a level of familiarisation that allowed us to drag the project leader (note a mathematical engineer) away from the controls in the demonstration production runs. The real accolade when customers began to ask what had the plant done to improve the properties of the material they were now supplying.

But E.T. is a precise task master. Without an understanding of the solid state metallurgy of the materials to be treated including rate processes, together with a quantitative understanding of how the materials, magnetic fields, inducing currents and supporting infrastructure interact - in fact, a full system study and control philosophy - success will elude you. As it did in original attempts in the 1950's in the US to apply transverse flux to strip and R.F. dielectric drying to paper. There should be a lesson somewhere for those academics responsible for the training of production engineers.

Apart from a short reference to "electrofoil" and "Chemelec" I have not devoted much of this talk to the ultimate in energy wise use, cold electron transfer or electrochemistry in the chemical industry. Nor of the scope of ion, glow discharge, laser, electron beams or electrophysics - which one can conceive of mating with 3D, CAD-CAM and intelligent robots to liberate design engineer's thinking. But as our first speaker demonstrated this can be a lecture in itself and apparently requiring a degree of liberation not yet discernable in many engineers.

The degree of co-ordinated effort, care and understanding needed to realise improvements in useful added value in an energy and/or resource constrained society we believe requires the dedication and close co-operation of a wide range of disciplines. But it can be done with E.T.

TECHNICAL AND ECONOMIC BASIS FOR IMPROVED INDUSTRIAL PRODUCTIVITY THROUGH ELECTRIFICATION

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INTRODUCTION

The term "electrification" dates to the first Edison station on Pearl Street in New York in 1882. A century ago, electricity's more enthusiastic proponents predicted a day when electricity would be so attractive as an energy source that it would virtually eliminate the direct use of fossil fuels. Into the '50's and '60's, utilities in the United States were actively promoting increased use of electricity as a "convenience fuel", even though the efficiency in many applications was low. In recent years, therefore, electrification has tended to take on a negative connotation, associated with inefficient use of energy. With the rapid rise of fuel and generating costs in the'70's, the price of convenience has grown dear indeed.

Electricity is not now, nor will it ever be, a cheap form of energy. Industrial customers now typically pay $15-16 per million BTU's for electricity, nearly twice the price of fuel oil and about four times that of natural gas. Does it then make economic sense to speak of "industrial electrification" in a world market where energy has become an increasingly important factor in the cost of production ?

If we think of electrification as the direct substitution of electrical BTU's for fossil-derived BTU's in the same process, the answer is clearly no, no more than it makes sense to burn Chippendale furniture in our fireplaces. If we recognize, however, that electricity is fundamentally different from chemical energy sources, and use it in fundamentally different ways to take advantage of its unique character, then we do, in fact, find a large number of situations in which electricity offers improved productivity, lower cost, and, in some cases, reduced primary energy consumption. The purpose of this paper is to highlight some of these unique characteristics and discuss their productivity implications. Several examples of processes already in commercial use will be presented to illustrate these points, and some promising emerging technologies will also be cited.

ELECTRICITY AS AN INDUSTRIAL ENERGY SOURCE

Industrial processes basically involve the interaction of energy and matter to transform materials from one form to another. Three types of interactive phenomena are unique to electricity: electromotive, electrothermal, and electrolytic.

Electromotive phenomena occur when an electric current flows normal to a magnetic field, producing a body force (known as the Lorentz force) in the conducting medium. The most familiar application is, of course, in electric motors. The ability of electricity to exert forces without physical contact also permits precision forming of parts by rapidly accelerating them against a rigid form (electromagnetic forming). One process now in the experimental stages would accelerate powders of difficult-to-form materials to hypersonic velocities using powerful current pulses, injecting them into a mold or onto a mandrel to form finished parts of amorphous metallurgical structure. Electromotive forces provide the only physical mechanism by which such materials can be accelerated to adequately high velocities.

Mechanisms to heat materials electrically are called electrothermal processes. The simplest is direct ohmic dissipation, in which a current is passed through the material to be heated by physically connecting electrodes to it. Conducting materials can also be heated without direct physical contact by electromagnetic induction. The material to be heated is placed in proximity to an electromagnetic coil in which an alternating current is flowing; fluctuating magnetic fields produced by the coil induce eddy currents in the material which are dissipated to produce heat.

Certain nonconducting materials can be heated dielectrically. This effect occurs when a material containing polar molecules (such as water) is placed in a rapidly alternating voltage field, inducing displacement currents. The dissipation of these currents produces heat, as, for example, in the familiar microwave oven.

The third category of electrical phenomena is electrolytic effects, in reality a manifestation of electromotive forces acting at the atomic and molecular level. Electrolysis is widely used for the separation of compounds of major industrial importance, as in the production of aluminum and chlorine, and related processes, such as electrodialysis and electroorganic synthesis, are becoming increasingly important in such areas as water treatment and chemical production.

PROCESS IMPLICATIONS OF ELECTRICAL PHENOMENA

The three electrical phenomena described above can have profound technical and economic ramifications when exploited for industrial production. From the technical point of view, electrical processing can provide unlimited input energy density, volumetric heat deposition, and precise controllability. In many cases, effects may combine in a synergistic way to short-cut production steps.

Technical Implications

Unlimited Input Energy Density: In combustion processes, the maximum achievable temperature is thermodynamically limited to the "adiabatic flame temperature", a practical limit of around 3000° F for typical industrial fuels burned in air. When heating a medium electrically, there is no inherent thermodynamic limit on the temperature. Typical temperatures in arc-produced plasmas of 10,000° F and higher are achieved routinely, and much higher temperatures are technically feasible.

High intensity heating with electric arcs finds important application in the steel industry in arc furnaces, where rapid melting is extremely important; melting rates 3 to 5 times faster than with combustion-fired equipment can be achieved in modern arc furnaces. For this reason, they are now used almost exclusively in scrap-based steel production. This process will be discussed at greater length in a later section. Other examples of importance in which high heating intensity is critical include plasma-based processes for chemicals and metals production.

Volumetric Energy Deposition: All of the electrothermal phenomena discussed above are volumetric, i.e., heat is generated within the material itself, a significant advantage in many processes. In the production of metal forgings, a rough shape (billet) must be heated to softening temperature so that it can be hammered or pressed into the desired form. In a conventional fuel-fired forging furnace, heating imposed at the surface by radiation and convection is inherently slow, typically requiring several hours. With induction heating, in which electrical energy is deposited directly within the material, the process is reduced to several minutes or less, offering the potential for higher production rate with significantly reduced energy and material losses, even taking into consideration the efficiency of electrical generation.

Another example of volumetric heating is the drying of moist materials with microwave or radio-frequency radiation. In conventional drying, heat must diffuse into the material from the surface, while moisture diffuses out, a slow process, since most materials of interest are poor thermal conductors. If drying is accelerated too much by intensifying the rate of heating, overdrying of the surface can occur, causing cracking and degradation of the product. With dielectric heating, this problem is largely eliminated [illegible] drying rates can be greatly increased, improving ove[illegible] productivity, product yield, and product quality.

Precise Controllability: Electricity is often referred to as an "orderly" form of energy, in contrast to thermal energy, which is random in nature. This orderliness means that electrical processes can be controlled much more precisely than thermal processes. Since electricity has no inertia, energy input can be instantly varied in response to process conditions, such as material temperature, moisture content, or chemical composition, to accurately maintain a desired state. Lasers and electron beams can be focussed to produce energy densities at the work surface a million times more intense than an oxy-acetylene torch. The focal points of these high intensity energy sources can be rapidly scanned with computer-controlled mirrors or magnetic fields to deposit energy exactly where it is needed. This can be a tremendous advantage, for example, in heat-treating of parts precisely at points of maximum wear, thereby eliminating the need to heat and cool the entire piece. In electrolytic processes, energy is imparted directly to ionic species to produce molecular separation or selectively induce chemical reactions, the chemical equivalent of microsurgery.

Synergistic Combinations of Electrical Effects: In some processes, electrolytic, electrothermal, and electromotive effects combine in an advantageous way. In the Hall process for reduction of alumina to aluminum, ohmic heating helps keep the cryolite bath in the molten state, while electrolysis causes pure aluminum to separate out and collect at the cathode. In a coreless induction melting furnace, electromagnetic induction heats and melts the charge while at the same time inducing a strong electromotive stirring action, which enhances heat transfer to the solid material and greatly improves homogeneity of the melt. The la[illegible] effect is especially important in the production of [illegible] alloy castings, and can be a major determining factor in [illegible]e choice of induction melting over alternative methods.

Economic Implications

The technical advantages of electrical processes discussed above have direct and important implications in terms of capital, labor, and energy costs, as well as beneficial impacts on the physical and human environment. The increases in production rate associated with high intensity and volumetric heating often translate into reduced fixed cost per unit of production. Capital requirements may also be reduced because fuel handling and environmental control equipment required for combustion processes are located at the power plant instead of the factory.

The economy of scale that is normally axiomatic for industrial facilities is much less significant in most electrical processes, permitting electrically-based plants to be built economically in small unit sizes. This offers increased opportunity for decentralization of production as well as capital benefits.

Precise control often results in higher raw material and finished product yields. In addition, the inherent controllability of electrical processes makes them especially amenable to automation.

The productivity factors highlighted here have been clearly demonstrated in a number of successful commercial processes. Several of these will be discussed in the following section.

CASE STUDIES OF ELECTRICAL PROCESS PRODUCTIVITY

Case 1: Electric Arc Steelmaking

The use of electric arc furnaces in the steel industry provides a convincing example of several of the basic points brought out above. While arc furnaces have been in use for specialty steelmaking for over 70 years, the past decade-and-a-half has seen tremendous growth in the industry for common carbon steel production. Arc furnace steelmaking based on scrap as a raw material competes with the conventional blast furnace/basic oxygen furnace process, in which coke provides the energy source.

Table 1 shows a breakdown of primary energy requirements for the two steelmaking routes. The BF/BOF process requires about 35 million BTU's per net ton of finished steel; 23.5 million BTU's, or about 2/3, goes into the production of molten steel. Most of this (19.6 million BTU's) is used in the coke-making and blast furnace operations. Electric melting of scrap requires about 7.4 million BTU's of primary energy (i.e., including consideration of the electric generating efficiency), or less than 1/3 of the energy for making molten steel by the BF/BOF route. An alternative to scrap for electric furnace charge is direct-reduced iron. While a negligible amount of steel is produced from this source in the U.S. today, it may become an important source in the future. Based on today's direct reduction technology, the overall energy requirement for steelmaking with DRI in electric furnaces is about comparable to that for the BF/BOF route.

Electric arcs provide the only heat source of high enough intensity to permit economic melting of scrap, in which melting rate is without question the most crucial production

TABLE 1

PRIMARY ENERGY REQUIREMENTS FOR STEELMAKING

Process		Primary Energy 10^6 BTU/net ton
Blast furnace/basic oxygen furnace		35.3
Ore agglomerating	2.3	
BF & coke ovens	19.6	
Steelmaking (BOF)	1.6	
Continuous casting	4.5	
Final finishing	7.3	
Scrap/electric furnace		19.2
Steelmaking (EF)	7.4	
Continuous casting	4.5	
Final finishing	7.3	
Direct reduced iron/electric furnace		38.6
Ore agglomerating	2.3	
Direct reduction	15.0	
Steelmaking (EF)	9.5	
Continuous casting	4.5	
Final finishing	7.3	

Source: Reference 1

parameter. During the past 15 years, there has been a continuous increase in furnace productivity, primarily brought about by increasing furnace specific power ratings. Ultra-high-power (UHP) furnaces rated at 350-500 kw/ton of capacity have reduced tap-to-tap cycle times for melting from 4-8 hours ten years ago to less than 2 hours today. New furnaces called extra-ultra-high-power (X-UHP) are now coming on line with ratings upwards of 650 kw/ton, further increasing melt rate and improving productivity.

Table 2 shows the comparative economics of the competitive processes. Scrap-based electric steelmaking shows a distinct cost advantage over blast-furnace steelmaking, and even with direct-reduced iron, production costs are quite competitive. Even more striking is the difference in capital cost per ton of capacity for the various processes. A scrap-based mill can be built for less than 1/4 the capital cost per annual ton of an integrated BF/BOF mill. Furthermore, it is economic to build electric mills in small sizes, permitting decentralization and siting near the markets for their products. In the U.S., 75% of the integrated BF steelmaking capacity is concentrated in the Western Pennsylvania/Eastern Ohio "steel belt" and the Chicago/Gary areas. Integrated plants are located in a total of 15 states, and average plant capacity is 3.25 million net tons/year. Electric mills, by contrast, are located in 32 states and average plant size is about 0.4 million net tons/year (4). Because they are characterized by relatively small size and proximity to markets, the plants have come to be termed "minimills" or "market mills".

From the standpoint of profitability, electric furnace steelmaking has clearly proven itself. Table 3 shows a comparison of 1979 financial results for the "Big Seven" integrated steelmakers and six major electric steel producers. Average profit per ton for the electrically-based mills was over 3 times that for the integrated mills. The electric mills have continued to fare relatively well during slow market periods, as they can be more efficiently run at reduced capacity, whereas BF/BOF mills have very limited turn-down capability and cannot be run economically at low production rates.

These factors have produced a clear-cut trend toward increased electrification of the steel industry. In 1978, 33 million tons of steel were produced in electric furnaces in the U.S., or about 24% of the total. The American Iron and Steel Institute projects that by 1988, electric steel capacity will exceed 50 million tons, or 1/3 of the total, an increase of over 50% in a decade (6). It has been further projected that electric furnace capacity will reach about 70 million tons by the year 2000 (7). This growth is driven by the favorable productivity rates achievable with high intensity heating, high energy efficiency, the capital and siting advantages brought about by reduced scale, and flexibility and compatibility with advanced automated production processes such as continuous casting.

TABLE 2

ECONOMIC PARAMETERS FOR STEELMAKING PROCESSES

Process	Production Cost ($/ton molten steel)	Capital Req't ($/annual ton capacity)
Blast furnace/basic oxygen furnace*	220	450
Scrap/electric furnace	175	100
DRI/electric furnace**	185	
DRI plant		150
Electric furnace		100

* Figures assume 70% hot iron, 30% scrap in BOF

** Figures assume 70% DRI, 30% scrap. DRI is assumed to be produced off-site and purchased by electric furnace plant.

Source: References 2 and 3

TABLE 3

1979 FINANCIAL COMPARISON-INTEGRATED VERSUS ELECTRIC STEELMAKERS

Company	Total Prod. Capacity (million tons)		% of Capacity Integrated/Electric	1979 Price/ton	1979 Profit/ton
National	12.7	Integrated	100/0	$ 489	$ 25
Inland	9.0		100/0	399	25
United States Steel	41.1		95/5	486	(12)
Republic	13.1		89/11	541	24
Bethlehem	22.2		89/11	443	40
LTV (Jones & Laughlin)	8.7		76/24	489	20
Armco	10.4		69/31	432	26
Cascade	0.13	Scrap-Based Electric	0/100	$ 383	$ 75
Chapparal	0.48		0/100	313	60
Florida Steel	0.98		0/100	357	41
Kentucky Electric Steel	0.18		0/100	348	74
Nucor	1.4		0/100	470	84
Roanoake Electric Steel	0.3		0/100	363	64

Average price/ton - Integrated steelmakers: $468; Electric mini-mills: $372

Average profit/ton - Integrated steelmakers: $21; Electric mini-mills: $66

Source: Reference 5

Case 2: Induction Heating of Forging Billets

Induction heating of billets was mentioned earlier as an example of the benefits of volumetric heating with electricity. This is manifested in terms of both energy consumption and overall production cost. Table 4 illustrates the comparative energy requirements for induction and competitive fossil-fueled billet heating furnaces. In both cases, typical industry-average efficiency values were used for each furnace type. Even considering conversion of fuel to electricity, induction can clearly be shown to be 20-25% more energy efficient than competitive combustion processes. Interestingly though, in contrast with arc furnace steelmaking, it is neither reduction in energy cost nor reduced capital requirements that make the induction heating process economically attractive.

Table 5 shows a cost breakdown for a typical forging operation (production of rock bits for oil and gas drilling), comparing induction and gas-fired furnaces. Installed equipment cost for the induction system is about 3 times that for the gas furnace for comparable service. Unlike basic steelmaking, however, capital is a relatively small element of overall production cost in this industry, amounting to only about 6% of material, labor, and energy expenses. Even though primary energy consumption is lower, energy cost for induction is still higher than for the gas-fired unit. How then can induction compete? The answer lies in more effective use of material and labor and the reduction of waste.

By reducing billet heating time from several hours to the order of a minute, loss of material due to oxidation, termed scale loss, is reduced by a factor of about four. Scrappage of finished parts is reduced by a comparable factor, and labor requirements are about half those for conventional fuel-fired forge furnaces, since induction systems are easily automated and require relatively little maintenance. Thus, savings in material and labor with induction more than compensate for the higher capital and energy costs, giving an overall cost per ton about 25% lower than for conventional heating.

These advantages have become well-recognized in the metals-fabrication industries. Growth in induction heating capacity of 10-15% annually through the 80's is anticipated, translating into additional electrical capacity requirements of 500-1000 megawatts/yr. Induction melting in the metal-casting industry has seen a similarly dramatic growth. From 1967 to 1980, the population of coke-fired cupolas for iron melting in foundries decreased by 46%; the number of induction melting furnaces increased by 77% during the same period (9). One of the country's largest energy users, General Motors Corporation, made a major commitment to electrification of its high temperature metal-fabrication processes starting in the mid-'70's (10). In 1979, over 75% of the company's melting, die casting, heat treating, and

TABLE 4

ENERGY REQUIREMENTS FOR FERROUS BILLET HEATING

Application	Furnace Type	Assumed Efficiency	Electricity Req't.(Kwh/ton)	Primary Energy (10^6 Btu/net ton)
Small billet heating	Slot/Box	15%	---	5.0
	Dual freq. induction	55%	400	4.0
Large billet heating	Pusher	19%	---	3.9
	Line freq. induction	75%	290	2.9

Efficiency for combustion furnaces is defined as ratio of heat in the metal to fuel energy input. For induction furances, it is defined as heat in the metal to electricity input at the plug. Primary energy requirement is based on assumed plant heat rate of 10,000 Btu/Kwh.

TABLE 5

ECONOMIC COMPARISON

INDUCTION AND GAS-FIRED HEATING OF FORGING BILLETS

Case Description: Steel hot- forging operation, 30,000 tons/yr throughput, 4,000 hrs/yr operation. Raw material value: $500/ton, product scrap value: $1,000/ton. Labor cost: $12/hr. Energy Cost: Electricity, $.06/Kwh; gas, $4.00 /MBtu.

Item	Induction Furnace	Gas-Fired Furnace
Installed Cost	$600,000	$200,000
Heating Efficiency	60%	15%
Annual Energy Cost	$720,000	$540,000
Scale Loss	1/2%	2%
Scrap Loss	1/4%	1%
Annual Scrap and Scale Loss	$150,000	$600,000
Labor Requirement	1 Operator	2 Operators
	1/4 Maintenance	1/2 Maintenance
Annual Labor Cost	$60,000	$120,000
Total Annual Operating Cost	$930,000	$1,230,000

Source: Reference 8

billet heating was still fired with gas. Nearly 90% of these operations were considered convertible to electricity, and of this, 70% has now been committed for conversion at a turnover rate of about 5% per year. Thus, it is anticipated that by 1990, over half of GM's metal-working operations will be electrically heated, primarily with arc and induction furnaces. This will mean a 34% growth in the company's electrical consumption between '79 and '90, coincident with a [illegible] drop in gas usage.

Case 3: Microwave Drying of Pasta

The example cases discussed above both relate to the high temperature metallurgical sector of industry. Important productivity gains have also been realized with electrical processes in lower temperature areas as well. Microwave heating has demonstrated significant potential, particularly in the food industry. In the drying of pasta products (e.g., noodles and macaroni) drying time has been reduced from about 4 hours to less than 1/2 hour, while at the same time providing higher uniformity and lower scrappage rates of the finished product (11). Total primary energy requirements are reduced by about 30% in comparison with conventional convection drying and capital cost for the microwave system is about 25-35% lower. Overall, microwave production cost is about 10% lower than for conventional processing. Similar economic benefits have been realized in other food processing applications, such as tempering of frozen meats, "proofing" of bakery products, and precooking of bacon and chicken.

THE FUTURE OF INDUSTRIAL ELECTRIFICATION

The examples cited above, while notable, are certainly not isolated; many other electrical technologies, such as the ones listed in Table 6, are emerging which demonstrate the same basic productivity-related technical and economic characteristics. Some of these, such as electrolytic reduction and infrared heating, are mature technologies that are continuing to improve through new developments in power semiconductors and digital control. Others, such as lasers and electron beams, are just entering the rapid-growth phase of their evolution, while still others, such as plasma chemistry and homopolar pulsed heating are still in the experimental stages.

The remainder of the 20th century has been widely proclaimed as the beginning of the Age of Information. The special characteristics of electrical processes discussed in this paper lend themselves well to the speed and precision of microprocessor control, and it is reasonable to expect that these processes will continue to grow in attractiveness with time. While this evolution will not occur overnight, an electrically-based production economy is a very realistic possibility in the long term. Perhaps the dreamers of Pearl Street were not so far off after all.

TABLE 6

SOME IMPORTANT INDUSTRIAL ELECTRIFICATION TECHNOLOGIES

High Temperature Materials Production

- Direct Arc Melting
- Induction Melting
- Vacuum Melting
- Plasma Arc Melting
- Direct Resistance Melting
- Electroslag Remelting
- Plasma Metals Reduction
- Plasma Chemical Synthesis
- Electrolytic Metals Reduction

High Temperature Materials Fabrication

- Induction Heating
- Laser Heating and Welding
- Electron Beam Heating and Welding
- Homopolar Pulsed Heating and Welding
- Direct Resistance Heating and Welding
- Electromagnetic and Electrohydraulic Forming
- High Temperature Plasma Surface Treatment

Medium and Low Temperature Materials Production

- Heat pumps and Vapor Compression
- Microwave Heating and Drying
- Infrared Heating and Drying
- Electrolytic Separation
- Electrochemical Synthesis
- Laser Chemistry
- Variable-Speed Drives

Coating and Finishing

- Ultraviolet Radiation Curing
- Electron Beam Curing
- Low Temperature Pla[illegible] Surface Treatment
- Electroplating
- Electrophoretic Painting

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ELECTRIC LOAD IMPACTS OF INDUSTRIAL ROBOTS

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Washington, DC

INTRODUCTION

Fervent discussion on the effects of industrial robots on industry and the national economy abound in the current press. Such direct effects of a new technology are widely prophesized and readily estimated, yet the indirect effects attract less notice and are not so easily quantifiable. With the goal of examining the indirect effects on energy usage from this automated technology, two case studies are presented here.

Science Management Corporation performed detailed analyses of the changes in electricity usage for two major factories resulting from the installation of industrial robot systems. The first case study examines the effects from a large welding robot system installed at Chrysler's St. Louis Assembly Plant No. 1. The second case study involves Franklin Manufacturing Company, a major wholesale freezer manufacturer, located in St. Cloud, Minnesota. The Franklin robot system, which was far smaller than Chrysler's, applied spray paint.

CASE STUDY NUMBER ONE: CHRYSLER CORPORATION ASSEMBLY PLANT

The first case study examines the effect of a robot system, employing 62 industrial robots, on the electric load of the Chrysler Corporation's St. Louis Assembly Plant in

Fenton, Missouri, near St. Louis. The assembly plant is a 2,214,500-square-foot facility that produces mid-size automobiles at an average rate of 480 units per day, single shift, straight-time.

The St. Louis assembly plant is a prime service customer of the Union Electric Company, headquartered in St. Louis. Union Electric bills Chrysler monthly for an average 14,900 kW kilowatt-demand and for approximately [illegible] million kilowatt-hours of electricity. Coal provides nearly all the space and process heat used by the factory.

In the summer of 1981, Chrysler *substantially renovated* the facility at a cost of $75 million. On May 4 production was halted while workers began rejuvenating the paint shop and the "trim/chassis/final" section. There were no significant changes in load for these sections, as equipment was being replaced by more up-to-date versions. During the same time, other workers and technicians were performing a major overhaul of the body shop. Floor space was expanded, computerized conveyor systems and 40 automatic machine welders were added, and an extensive robot system equipped with 62 industrial robots was installed. The components listed below comprise the robot system:

- sixty-two Unimate 4006B hydraulic, industrial robots
- a major upgrading and enlargement of the conveyor system
- a Robogate proprietary car-body positioning system
- a central programmable logic controller (PLC)
- an intricate network of Allen-Bradley remote PLC's, sensors, and switches
- sixty-two Weltronic robotic weld controllers
- sixty-two robotic weld guns (designed by Chrysler).

Excepting the weld guns, all the components have constituted an increase in kW-demand to the factory. The difference in electric usage between the automatic and the previous, manual welding guns was statistically insignificant.

Typically, a car body will receive welds in one of the two "Re-spot" stations, where a team of four robots will apply first welds to hold the pieces together and to make initial structural welds. The body then continues to one of two sets of six robots at the "Pre-tack" station; the assembly line advances at intervals with pauses for the robots to apply the welds. The process controllers and other components of the sensory network communicate, via a data highway link, the positions of the bodies to the central computer. After the pre-tacking is finished, the car bodies are transferred to the Auto-frame, or Robogate, section where five robots on the left and on the right sides of the unit perform a series of essential welds which join the body integrally. The Robogate system precisely positions and secures the auto-bodies with respect to the robots. *The Robogate assemblage consists of two 40-hp* hydrostatic drives on each side of the body, a 75-hp transfer gate, two 20-hp hydraulic lifter drives, and the controller linked to the main console. The body then continues to the Auto Re-spot section where 32 robots complete the framing process and produce a solid, one-piece unit. From here, the body is transported to the next phase of the manufacturing operation. In all, over 500 welds are applied to the body within a cycle time averaging considerably less than one minute per unit.

To calculate electric energy usage accurately and to account for the capacity additions exclusive of the robot system, two approaches were used. The first approach included an analysis of covariance which regressed on monthly maximum kilowatt-demands. This analysis employed two terms representing unit production and one accounting for thermal loading as covariates. The regression was performed over the period extending from one year before to nearly one year after the robot system installation. The analysis relies on monthly maximum kilowatt-demand as opposed to kilowat-hour usage because all maximum demands occur during main production hours when the robot system is operating. The kilowatt-hour term is cumulative and, thus, records off-hour vagaries of production. The regression analysis of covariance was highly successful and the output is summarized in Table 1. The R-square term equals 96.2 percent, and the probability->-F values represent 99% or greater probabilities of correlation significance.

TABLE 1 - ROBOTICS EFFECT ON KILOWATT-DEMAND LEVEL REGRESSION PROCEDURE FOR SELECTED VARIABLES

MAXIMUM R-SQUARE IMPROVEMENT FOR DEPENDENT VARIABLE: KILOWATT-DEMAND

R SQUARE = 0.9623
C(P) = 6.0669

	DF	SUM OF SQUARES	MEAN SQUARE	F	PROB>F
Regression	4	57633750.1	14408437.5	76.7	0.0001
Error	12	2255803.7	187983.6		
Total	16	59889553.9			

INDEPENDENT VARIABLES	B VALUE	STD ERROR	TYPE II SS	F	PROB>F
Intercept	7919.5				
Units of Production	-0.691	0.128	5487201.0	29.19	0.0002
(Units of Production)$^{1/2}$	126.86	14.789	13832463.4	73.58	0.0001
(Cooling Degree Days)^2	0.0043	0.001	1661411.1	8.84	0.0116
Robot System Installation	2279.9	229.496	18552737.1	98.69	0.0001

The kilowatt-demand due to all the installations performed during the plant closing is estimated at 2280 kW, normalizing for production units and degree days. With a 95 percent confidence level, the confidence interval is estimated at 1780-2780 kW. These figures include, of course, the increases due to the additional machine welders and the increase in floor space. In any major facility there is a certain amount of electric load that is associated with and proportional to the floor space. Chrysler's facility was exemplary in this respect; with data supplied by Chrysler an estimated increase of 230 kW was calculated for the additional floor space. The 40 new automatic machine welders contained hydraulic motor drives, averaging 30 hp per machine welder. Based on a visual inspection and on the cycle-time parameters, the percentage of time the motor was charging the accumulator (accumulator factor), as compared to by-passing, was estimated at 40 percent. This translated to a 390 kW capacity addition due to the installation of the automatic machine welders. The electric usage of the welding from the 40 automatic machine welders does not affect the before-and-after analysis because the number of welds is constant per unit, and all calculations of electric effects are normalized on a per unit basis.

The present estimate of average capacity increase from the robot system is 1660 kW or:

2280 kW	Regression analysis estimate
(230) kW	Due to floor space increase
(390) kW	Due to 40 new automatic welders
1660 kW	Robot system kW-demand.

Statistically, the robot system draw has a confidence interval of 1300-2020 kW at a 95 percent confidence level, given an equal distribution of error terms. This assumes no significant increases from the other rejuvenations and alterations that took place during the plant outage, an assumption based directly on discussions with Chrysler's electrical systems engineers in the plant.

The second approach to estimating the electric usage effects of the robot system involved straightforward calculations of those components that represented kW draws. A resultant 1246 kW total robot system demand was obtained. All calculations used conservative assumptions where applicable. The calculations for the hydraulic power units follow directly from the equations developed by the Chrysler engineering group involved with robotics. An accumulator factor of 35 percent, derived from observation, is used. The estimates for the robots' electronic controls result from direct measurement of similar electronic controls for industrial robots. The values assigned to the Robogate and conveyor systems were calculated from data supplied by the system design group at Robogate Products, Inc. Estimates for the production control, including PLC's, sensors, switches, and main controller follow from direct measurement of analogous systems for robotics installed at a less massive facility. A summary of the values derived from these calculations appears in the following table.

TABLE 2. BREAKDOWN OF COMPONENTS' AVERAGE kW-DEMANDS

• Industrial Robot (62)	
Hydraulic Power Units	530 kW
Electronic Control	12 kW
• Line Automation	
Robogate System	100 kW
Conveyor System	600 kW
• Robot System Control	
PLC's, Sensors, Weld Controllers, Switches, & Main Controller	4 kW
TOTAL ROBOT SYSTEM kW-DEMAND	1246 kW

The mean value of 1450 kW from the two approaches for the robot system is employed. The system accounts, therefore, for 64 percent of the capacity increase appearing after the installation. This value is applied to the energy analysis section that follows.

The results of the analysis that follow are values and displays determined by several statistical computer techniques developed for this study. Data on quarter-hourly electricity usage for the past two years was supplied courtesy of the Union Electric Company. Production data from Chrysler and weather data from the National Climatic Center were used for some of the values already described and for the normalizing factors essential to the analysis. The Chrysler facility was closed for the installations from April 30 to August 17, 1981, so the results are timely as well as accurate within the bounds of data reporting. The robot system operates in concert with the major worker shifts, and its electrical effects are felt predominately during those periods. The computer output summarizing the major effects appears in Table 3, below.

TABLE 3. ELECTRICITY EFFECTS DUE TO INSTALLATION OF THE ROBOT SYSTEM

	Maximum Kilowatt-Demand Level	Kilowatt-Hour Consumption
Winter	+ 24%	+ 20.8%
Spring/Fall	+ 12.4%	+ 17.1%
Summer	+ 12.9%	+ 13.8%
Annual Average	+ 15%	+ 17%

Vacations and reduced production schedules explain the large percentage increase in maximum kilowatt-demand levels during the winter. The robot system's demand is less dependent on production than are other parts of the assembly line. During the winter, demand is low to begin with, and, thus, any increases correspond to larger percentage increases. Still, all the values are quite high and reflect the strong influence of the robot system.

Figures 1 (a), (b), and (c) present normalized mean weekly load profiles for the Chrysler plant during winter, spring/fall, and summer. The dashed line indicates values after installation and the solid line, values before. In general, the kW-demand is higher consistently throughout the week but, as is expected, is highest during peak production hours.

Table 4 exhibits effect on load factors of the robot system. The load factor, defined as the average kW value divided by the maximum kW value during a given period of time, is crucial to a utility's operation. Changes in the individual load factors of large plants, such as Chrysler, suggest future changes in the service area's load factor. The change in load factor is significant at the Chrysler plant and is a potentially hopeful sign to the servicing utility of a more level electricity demand.

TABLE 4.- LOAD FACTOR DETERMINATION
(kW-Mean/kW-Maximum)

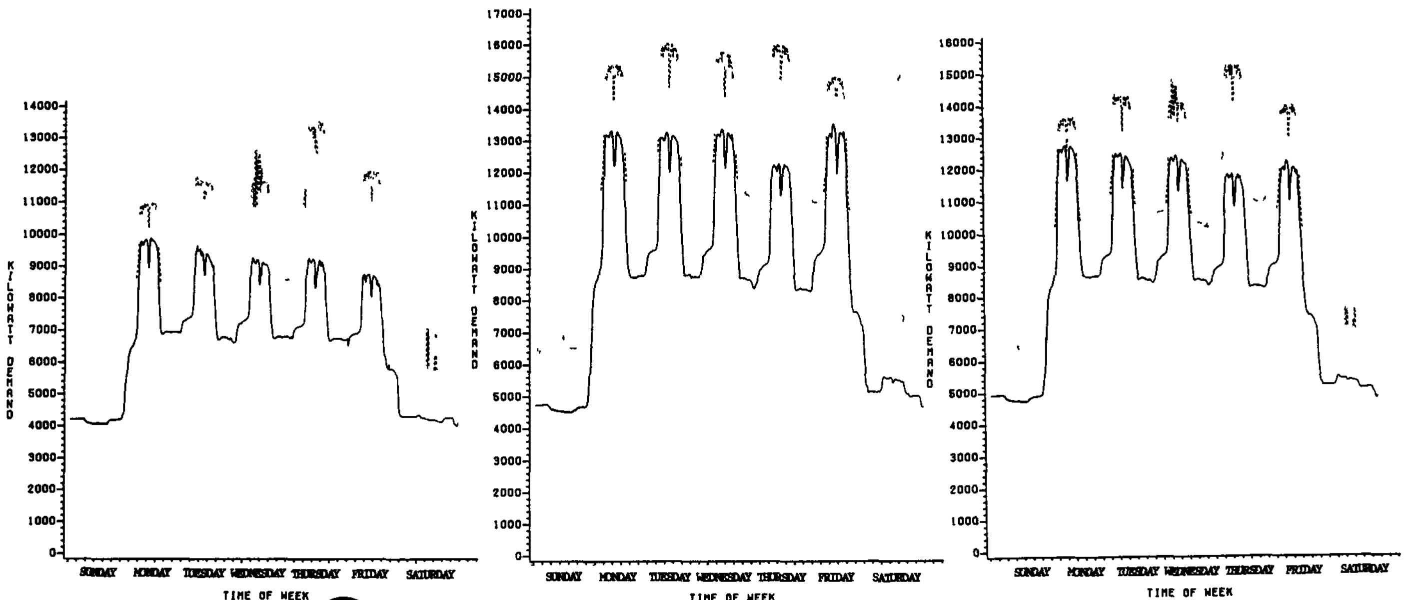
Season	Load Factor Prior to Installation	Load Factor Before Installation	Percentage Change Due to Robot System
Winter	0.6695	0.6454	- 2.29%
Spring/Fall	0.6475	0.6880	+ 3.98%
Summer	0.6644	0.6722	+ 0.75%

CASE STUDY NUMBER TWO: FRANKLIN MANUFACTURING COMPANY

The second case study chosen involved the Franklin Manufacturing Company's manufacturing plant in St. Cloud, Minnesota. Franklin is a major domestic producer of freezers for wholesale distribution. The St. Cloud plant is a highly automated, one-half million-square-foot facility which uses assembly-line operations to manufacture in excess of 500,000 freezers per year. Franklin employs roughly 800 people, and its operations vary from one-shift to three-shift, depending on consumer demand and season. The facility uses on average 1.5 million kWh per month and has a typical maximum kW-demand of 4,300 kW. The majority of

FIGURE 1. MEAN WEEKLY LOAD PROFILES

(a) WINTER SEASON (b) SPRING/FALL SEASON (c) SUMMER SEASON



space and process heat is furnished by natural gas. Both electric and gas-service are provided by the Northern States Power Company (NSP) of Minnesota.

Motivated by a desire to improve productivity in the section of the assembly that paints freezer-liners, Franklin explored the feasibility of installing spray-painting industrial robots in the late 1970's. The company developed a system with four Nordson Industrial Coating robots. The peripherals that completed the robot system included: the end-effector, a Nordson electrostatic paint gun for each robot; a Nordson licensed computer for program control; a unique sensory system designed in-house with assistance from Nordson; two air-conditioning units installed to prevent computer failure in the robot control room; and a hanging conveyor system that underwent major alterations for integration with the industrial robots. All components, excepting the painting guns, have represented capacity additions to the electric load. The power requirements for the painting guns were nearly the same as those for the manual painting gun.

The robot system is fully integrated with the rest of the assembly line. The conveyor system is manually fed and transports unpainted, steel freezer cabinet liners on hooks to the spray-painting booth. Prior to the booth, the liners pass by an in-house-developed sensory system. The sensory system identifies the model freezer that accommodates the liner and sends a signal to the computer control, initializing the appropriate spray-painting program. This program is transmitted to the industrial robot which awaits a signal indicating that the liner is presently in the start position. Upon receipt of the signal, one robot applies a coat of paint on the top, back, and bottom of the inside of the liner while another sprays the two sides. A second set of two robots paints a second coat on the interior five sides. The liners then leave the booth and are transported to the next stage of the coating operation.

The calculations of the average electricity load due to the robot system were relatively straightforward. The main-feeder was measured for amperage against known voltage. The resulting value was verified by individual measurements and nameplate-rating checks, and power ratings for necessary peripheral equipment to the system were added. The power contributions are broken down as follows:

- Each Robot Hydraulic Unit (4):
  - -- 480 V, 1Ø
  - -- 3 to 12 amps
  - -- 2.5 to 10 kW (average value: 6.25 kW)
- Robot Electronic Unit (4):
  - -- 480 V, 1Ø
  - -- 1.5 amps
  - -- 700 W

- Electronic Panel:
  - -- 480 V, 1Ø (power for PLC's, photo-eyes, solid-state controller, start switches)
  - -- 2 amps
  - -- 1 kW
- DC Drive:
  - -- 480 V, 1Ø
  - -- 4 amps
  - -- 2 kW (10 percent increase from manual operation)
- Air Conditioners (2) (required for robot system):
  - -- 240 V, 1Ø
  - -- 18 amps each
  - -- 8.6 kW

The robot system, thus, accounts for an approximate 37.6 kW increase to the manufacturing plant load.

Although most of the values followed from direct observations, two qualifying assumptions were used:

- The change in motor drive from AC to a synchronous DC drive is presumed to increase power needs by 10 percent.
- The air conditioning units, necessary for the computer room, will require continuous operation.

Using the value of 37.6 kW as an average load from the robot system, the effects on kilowatt-hour consumption were computed. The 37.6 kW value was applied to existing data obtained from Northern States Power (NSP) to develop "before" and "after" views. The robot system being installed in April 1980 provides an up-to-date picture of resulting electric usage effects.

The number of shifts at Franklin has been irregular and the utilization of the robot system varies accordingly. To compensate, the average number of shifts per work-week was calculated from production data. The number of shifts was correlated with the robot system's normal schedule of operations. The data were merged with Franklin's electricity history recorded on magnetic tape to furnish estimates on electricity consumption effects. A normalized computer program was written to quantify these data. A summary of the computer output is presented here.

TABLE 5. ELECTRICITY EFFECTS AFTER INSTALLATION OF ROBOT SYSTEM

	Kilowatt-Demand Level	Kilowatt-Hour Consumption
Winter	+ 0.30%	+ 0.50%
Spring/Fall	+ 0.86%	+ 0.68%
Summer	+ 0.49%	+ 0.67%
Annual Average	+ 0.63%	+ 0.63%

A reduction in shifts during the winter months explains the more modest increases to both the kilowatt-demand level and the kilowatt-hour consumption. In all cases the increases attributed to the robot system have been small, which was expected given the small number of robots and the large assembly operation.

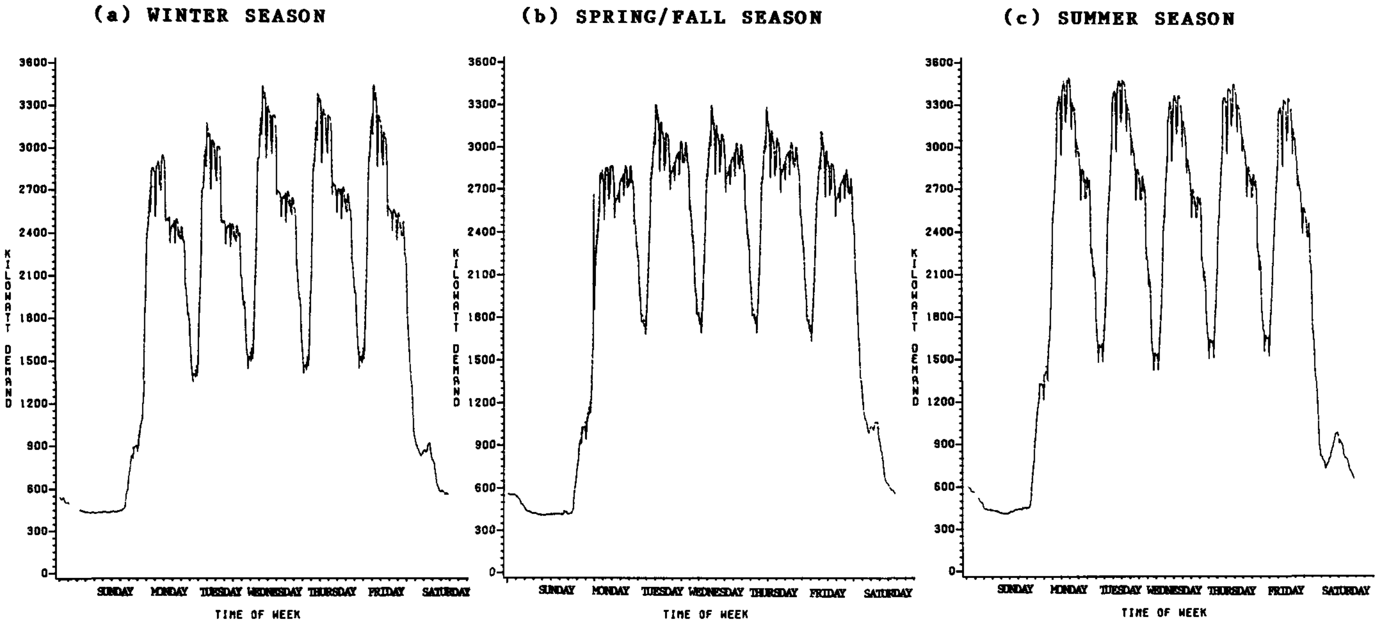
Figures 2 (a), (b) and (c) exhibit weekly load profiles for the manufacturing plant during the three distinct seasonal periods: winter, spring/fall, and summer. The dashed line indicates values after installation and the solid line, values before. Where the solid line only appears, there were no significant changes before and after installation of the robot system. The load shapes were plotted from a statistical program assigning the mean values for each time increment during the applicable seasonal period with data originating from the magnetic tape readings supplied by NSP. As is evident, there is little substantial effect, though it is worth noting that the slight increases occur often during the upward slope of the profiles.

As noted in the Chrysler case study, the load factor, defined as the average kW value divided by the maximum kW value during a given period of time, is critical to a utility's operation. Changes in the individual load factors of medium-to-large size plants, such as Franklin's, can be harbingers of alterations in the service area's load factor. In this case, the change in load factor is barely significant, with values never exceeding 0.2 percent. The findings are summarized in Table 6.

TABLE 6. LOAD FACTOR DETERMINATION
(kW-MEAN / kW-MAXIMUM)

SEASON	LOAD FACTOR PRIOR TO INSTALLATION	LOAD FACTOR AFTER INSTALLATION	PERCENTAGE (%) CHANGE IN LOAD FACTOR
WINTER	0.554196	0.555272	0.19422
SPRING/FALL	0.614605	0.613537	-0.17392
SUMMER	0.588027	0.589112	0.18454

FIGURE 2. MEAN WEEKLY LOAD PROFILES



CONCLUSIONS

For Chrysler, the robot system has constituted a significant increase in the plant's electricity usage. The results show that given a constant rate of automobile production, and assuming similar weather conditions, plant operation with the robot system will increase the kW-demand over operation without the system enough to noticeably affect the plant's electric bill.

The load factor is substantially improved; small upscales of the service area's total load factor will translate into large savings from enhancement of power plant operating efficiencies. The effect on power factor for the service area is more questionable. Although not specifically addressed here, similar robot systems put into operation in the near future will probably degrade slightly the power factor of the servicing utility.

From the perspective of the Franklin manufacturing plant, the effects of the robot system are slight. The increases in electricity usage, normalizing for output, were equal for power and energy effects. The power increase, however, has the greater effect on the company's electricity bill.

The effect of the Franklin robot system on electricity usage, in itself, is insignificant. Yet, it demonstrates certain meaningful trends. The commensurate results on kilowatt-demand and kilowatt-hour usage suggest that large-scale implementation of robot systems similar to Franklin's would neither help nor degrade a utility's system load factor. The power factors of the utility's major customers may continue to worsen with an influx of this technology. The tendency for the robot system's largest effects to occur during the upward sloping portions of the load profiles may be slightly troublesome on a larger scale, in that this "stepping-up" portion of the load profile typically coincides with the utility's stepping-up period. This tendency may indicate a need for greater use of combustion turbines and similar quick start-up units or of specific load management techniques.

ACKNOWLEDGMENTS

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REGIONAL ELECTRIC PLANNING UNDER UNCERTAINTY

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INTRODUCTION

Two major issues in electric power planning are (1) control of the financial risk inherent in basing new-capacity plans on single, best forecasts of electricity demand when these forecasts are highly uncertain, and (2) the use of regional regulation in lieu of state regulation as a means of promoting greater efficiency in power supply (and lower overall cost). This paper describes an approach to electric-power planning that is currently being developed for use in the Pacific Northwest which may have potential for dealing with both of these issues.

Uncertainty in construction costs and consumer demand is having a major impact on electric utilities' efforts to plan the construction of new resources for meeting future electricity needs. With construction times for thermal generating plants ranging from 7 to 12 years, a small error in projecting future demand can result in costly and politically embarrassing planning mistakes. Too great an excess of capacity can be very expensive for the rate payer. A major shortage of capacity can be even more expensive in terms of productivity and developmental prospects for the community at large. Both can lead to painful political outcomes.

The rapid rise in construction costs has led to the recent emergence of a new issue. The possibility of creating regional regulatory frameworks to promote the development of *regional* markets for power has been discussed as a *possible* method of controlling the need for high-cost construction. Such frameworks, supposedly, will expand the market available for supply by the most efficient generating resources, thereby promoting the development of less expensive electricity and reducing the need for large, expensive construction projects. This prospect has been raised both within the United States Department of Energy and in media serving the utility industry.(1)(2)

The Pacific Northwest is currently developing a planning approach that explicitly utilizes a regional framework in dealing with the problem of supply planning under conditions of uncertainty. Under the guidance provided by the United States Congress in the Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501) (Regional Act), the governors of the four states of the Pacific Northwest* in 1981 created a regional electric power planning council to assure an adequate supply of electricity for the region and to promote the development and equitable allocation of the least expensive electricity resources. This council, the Northwest Power Planning Council (Council), has approached its task with the assumption that the future power needs of the region are highly uncertain. The Council has argued that, since new-capacity construction costs are so high and uncertain themselves, no logical basis exists for selecting one demand projection over others and investing to meet that projection exclusively.(3)

This philosophy has led the Council to adopt an approach to power planning that includes plans for the development of relatively small (as well as large) increments of power and provides for the early termination of projects if demand does not develop as forecast. All or part of the cost of terminated or mothballed projects will be paid by the region's rate payers under the concept that these costs are risk-management costs--or risk-insurance premiums--for the region as a whole.** The remainder of this paper describes this planning approach.

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* Washington, Oregon, Idaho and Montana.

** Written descriptions of the Council's planning philosophy, the complete details of which were still

THE NORTHWEST'S PLANNING APPROACH

In Figure 1, a pair of schematic demand forecasts are shown. These represent limiting high and low demand forecasts for the region. They are based on a "consensus" within the forecasting community that actual demand will lie between the upper and lower bound for

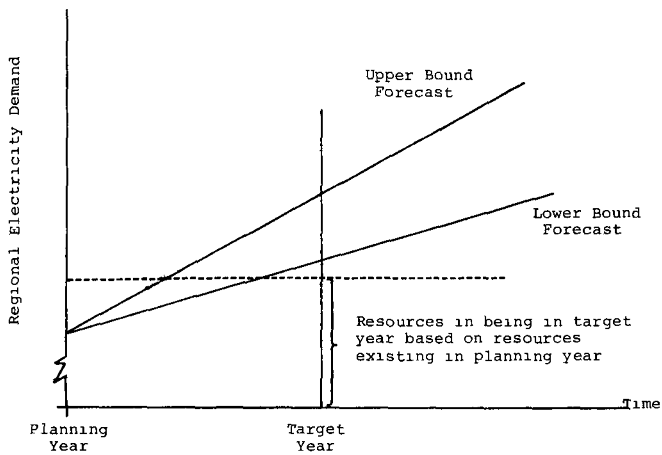

FIGURE 1. UPPER AND LOWER BOUND "CONSENSUS" FORECAST

being developed as this paper was being written, are available in several discussion papers prepared for the Council. The principal concepts are developed in Kai N. Lee, "The Path Along the Ridge: Regional Planning in the Face of Uncertainty," March 1982. (4) Additional material is in a series of issue papers and memoranda developed by the Council staff. Principal among these are two papers entitled "Resource Options" and "Conservation Purchase: What is the Region Buying." (5) These three papers and discussions with the Council staff provided the source material for this paper. Each of the papers are available from the Northwest Power Planning Council, 700 S.W. Taylor Street, Portland, Oregon 97205. Kai Lee, in his paper, attributes the initial conceptualization of the planning approach to Richard Watson, Steve Aos, John Douglass and Peter Downey in an unpublished paper entitled "Power Planning and Uncertainty" developed for the Washington State Energy Office.

each target year. Given these boundary forecasts the planning approach uses the following basic rules:*

1. The power supply plan for the region must assure that resources are adequate to meet the lower bound forecast for each year of the planning period. Plans must be developed to purchase resources to meet this bound.

2. The plan must assure that a combination of purchased and optioned resources are available to meet the upper bound forecast for each year of the planning period. Plans must be developed to option resources to meet this bound.

3. Standards must be available and used to screen resources offered as options. These standards might include criteria for reliability, time of availability and cost per kilowatt hour (kWh).

4. The plan must be reviewed frequently so that the mix of options and resources can be adjusted in the light of new information.

Figure 2 illustrates how the V-shaped space between the lower and upper bound forecast is filled. Looking at the target year from the vantage of planning year, the planner must rank the possible resources in the order of their increasing expected cost per kWh.

Lead times for the possible resources will vary. Some may already be under development. Some projects, such as project 1, do not need to be started yet. In three cases--projects 2, 3 and 6--a decision must be made in the current planning year.

Before continuing with this description of the Northwest's approach, it must be noted and emphasized that the resources being considered to meet regional demand are not limited to conventional large-scale thermal power plants. Although conventional resources are part of the resource portfolio, the planning approach relies heavily on smaller-scale resources to control the economic risks created by uncertain forecasts. Thus, in the Pacific Northwest, conservation projects, renewable resources, cogeneration and other non-traditional technologies are consciously incorporated into the planning scheme.

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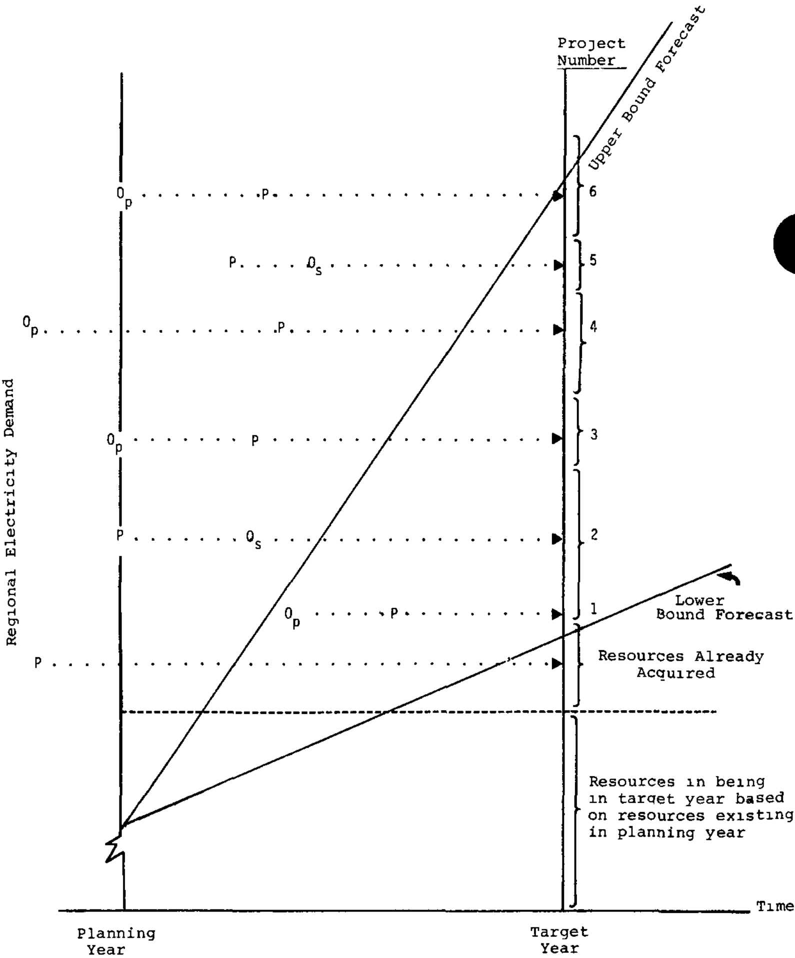
* The following material is based primarily on Lee (3).



O_p Decision point for option to purchase a resource

O_s Decision point for sales option on the output of an already purchased resource

P Decision point for the purchase of a resource

. . . . . Permitting and construction lead time

Source, Lee (3), p. 14; modified by authors.

FIGURE 2: EXAMPLE OF PLANNING OPPORTUNITIES TO DEVELOP RESOURCES FOR A TARGET YEAR

Returning to Figure 2, we can see that project 1 does not have to be examined in detail in the planning year even though, among the resources to be available for meeting the possible demand above the lower bound in the target year, it is expected to be the least expensive. On the other hand, decisions must be made on projects 2 and 3 if their resources are to be available in the target year.

REGIONAL COST-EFFECTIVENESS CONSIDERATIONS

The situations created by projects 2 and 3 illustrate the tradeoffs between regional cost-effectiveness and flexibility that give this planning approach its professed ability to deal with uncertainty.

Skipping project 2 for the moment, a decision must be made on project 3 in the planning year regarding whether to obtain a "purchase option" on that project. This involves a decision whether to begin the project but limit the risk by taking an option to complete the project at a later date if the demand warrants.

Just what constitutes a purchase option on a project--or more precisely, on a resource--is one of the issues in this planning approach. Essentially, a purchase option, as currently conceived is any type of agreement to begin the development of a resource but not complete it until a second commitment (a purchase) is made at a later date. (3) Purchase options might consist of permitting activity for a specific project, engineering design work, or ground breaking for construction foundations. The agreement would specify the amount of the developer's initial work on the optioned resource for which the region would pay--regardless of whether or not a completed resource was ever purchased.

Project 3 will be reevaluated at frequent intervals up to decision point P (Figure 2), at which time the region's planners will be forced to make a commitment to (1) full development, (2) mothball, or (3) terminate. Project 3 may also be terminated or mothballed at the end of any one of the evaluation intervals (not shown in Figure 2) if the demand for its output does not develop. The region will absorb all or part of the cost of project 3 up to decision point P depending on the terms of the option agreement.

Cancellation of project 3 due to low demand growth will result in higher costs to the region's rate payers than would be the case if a traditional single-point demand forecast had been used, it was precise, and project 3 had never had to be optioned. It is an explicit premise of this planning approach, however, that planners can no longer assume high precision in their forecasts and, therefore, must proceed on an assumption of uncertainty. This, inevitably, leads to higher costs to the region than would be expected if high forecasting precision could be assumed.

The increment in cost to the region due to planning for uncertainty is the "risk insurance premium" mentioned earlier--or the price paid for risk management. It reduces the cost-effectiveness of this planning approach relative to more traditional approaches which assume that a single forecast demand can be used as the planning target--unless, of course, that single forecast badly misestimates the actual demand. On the other hand, if one incorporates a measure of planning reliability into the effectiveness index one is using, then an approach to planning that explicitly provides for uncertainty might be more cost-effective than one that does not, in spite of the higher costs. (Another issue that remains to be examined is whether by spreading this additional cost and the resulting reliability over a multi-state region the cost-benefit ratio for ratepayers in the region is lower than it would be if the approach were limited to a state or service area.)

Project 2 illustrates another of the cost-effectiveness dilemmas that this approach can create. As shown in Figure 2, project 2 is not suitable for optioning and must be purchased in the planning year if its output is to be available in the target year. If project 2 is purchased, i.e., a financial commitment is made to its full development, an irreversible commitment will have been made to higher-cost power before the lower-cost power available from project 1 is purchased. If the planning process waits for the project 1 decision point, however, project 2 will no longer be available to come on-line in the target year. In this case, if the demand develops, higher-cost resources with shorter lead times, such as project 5, might have to be developed.

If project 2 is, therefore, purchased in the planning year, and the level of demand for which it was purchased does not develop, the region either will have excess higher-cost power or can elect to reduce the excess by not purchasing project 1 when that decision comes due. In either case, the region will have purchased a project that is less cost effective that one it might have had had it waited. Once again, this planning approach will have cost the region more than an approach which assumes more certain knowledge of the future demand (provided the assumption is justified). The cost difference, again, is the risk insurance premium mentioned earlier.

One way of "controlling" the risk inherent in purchasing project 2 in the planning year is to seek a buyer and negotiate an option with the buyer to purchase the project's output power at a pre-determined price. This so-called "sales option" (O_S) gives the region a chance to provide a degree of assurance that there will be a buyer for the more expensive power in the event demand for the output of project 2 does not develop. In this event, however, the buyer's purchase of power from project 2 may displace his purchase of less-expensive power from already-existing resources. This would compound the cost-effectiveness problem for the region. Of course, if project 2 cannot be aborted, and the demand does not develop, the penalty to the region's rate payers from selling project 2 power in lieu of cheaper power will be less than if they had to pay for a non-producing project 2.

NEXT STEPS

The planning approach outlined in this paper is in a conceptual stage. The basic ideas are well-established in business and investment analysis. Applying them to the needs of long-range power planning, however, will be challenging. Numerous practical questions have yet to be answered. Two have already been mentioned:

- What form can a viable purchase-option agreement take?

- Will the costs to a region's rate payers, in fact, be less if planning is undertaken on a regional level than if it is performed on a state or service-area level?

Other questions include:

- How is a "consensus" on limiting high and low forecasts developed?

- Will the cost of optioned resources be considered different from construction work in progress? If not, when can the "risk insurance costs" be included in rates?

- What form of planning and regulatory authorities will have to be created to manage/regulate this approach? How will these changes be accomplished?

- What conditions of power supply must exist before the approach is economically attractive for a region?

- Why would developers want to sign purchase-option agreements and initiate projects that, if terminated, will probably break even but not show a return on invested funds? What level of incentive will be necessary to compensate for the loss of retu

- Can authorization be obtained for expenditures for options or purchases to cover the upper portion of the "V" where the likelihood of need for power is low?

- Are there sufficient resource-development opportunities of the types that will permit a low level of expenditures during the initial development stages to make the planning approach viable for the long term?

- Do we know enough about the availability, means of promoting development, and reliability of conservation as a resource?

The Northwest Power Planning Council has initiated steps to develop answers for some of these questions as they pertain to the Northwest region. As this paper was being written (early January), a draft regional power supply plan was being prepared for publication in early February. A final version of this plan is due in April. Studies of the characteristics of specific resources as they relate to the Council's planning approach are underway. A program for monitoring regional demand and supply development is being designed.

The proof of the pudding, of course, is in the eating. The Northwest is fortunate in that the anticipated conditions of energy shortage that created the Regional Act have become projected surpluses. As a result, the region can "afford" to experiment with its planning approach for several years with little risk of creating energy shortages. Such experimentation will also be a valuable next step.

CONCLUSIONS

The situation in the Pacific Northwest is different from that in most other regions of the country in that many years of low-cost electricity are presumed to have created a large potential for electricity conservation, and the presence of the Bonneville Power Administration as marketer of 80% of the region's electricity greatly facilitates regional planning. There are signs, however, that the time for reform of power planning approaches elsewhere may be near. The Northwest's planning approach could serve as a model for such reform. National calls for regulatory reform make some form of a regional planning and/or regulatory authority a possibility. The high cost of new capacity and resulting rate-payer revolts have created a public mood that is supportive of solutions which hold out the promise of lower rate increases. Uncertainty in demand projections coupled with the high cost of new capacity has already led several state utility commissions to require increased conservation activity by electric utilities.

The Northwest Power Planning Council's approach to power planning offers a conceptually attractive alternative to existing approaches. Much work and experimentation remain, however, before it will prove to be an effective alternative. The fascinating aspect of the approach lies in the Northwest's authority and will to try it. Given the emergence of comparable calls for reform elsewhere in the nation, the Northwest's regional experiment in cost-effective power-supply planning under conditions of uncertainty will be worth watching.

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THE EPRI LOAD MANAGEMENT STRATEGY TESTING MODEL

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In these times of expensive energy, electrical system planners are seeking ways to reduce system costs by looking at how electricity is used as well as how it is supplied. Planners have always sought to reduce supply costs. The emphasis on demand-side strategies such as conservation, direct load control of water heaters and air conditioners, and time-of-use pricing is relatively new. These newer strategies require new evaluation techniques.

This paper describes the results of an EPRI-conducted project which offers utility planners a powerful new tool for evaluating demand-side options. This tool is known as the Load Management Strategy Testing Model or LMSTM.

We believe that this model will be particularly useful to the utility industry because demand-side planning is more difficult than supply-side planning. There are at least four reasons for this:

1. There are a larger number of options and combinations of options to consider. The general categories of options include direct control of appliances, conservation and time-of-day pricing. The number of variations within each category is almost endless and frequently they are considered, not one at a time, but in combination. Further, the complementarities

and substitutability among options makes it particularly difficult to evaluate combinations of options.

2. The traditional evaluation criteria, cost effectiveness, is inappropriate for evaluating some demand-side alternatives, particularly options that involve price structure changes. Analysis of time-of-use rates, for example, requires that cost-effectiveness methodology be replaced by a cost-benefit methodology. Traditionally, electrical system planners have begun their task with the premise that customer demands are fixed. Beginning with that premise, the planner's objective was to meet these demands at minimum cost, subject to maintaining prespecified standards of reliability. Planning and analysis in this case was properly concerned only with building and operating a low-cost generation, transmission, and distribution system. Given this situation, a plan is desireable if it is cost-effective.

   With the introduction of demand-side options, planners can no longer take the customer loads as given. Advocates of demand-side strategies believe that coordinating customer and utility decisions in nontraditional ways will produce systemwide gains. In response to this change, planners must extend their analysis to include the customer impacts such as changes in the amount of energy purchased or direct investments for increased efficiency and conservation. Other demand-side impacts that are not normally covered in a cost-effectiveness evaluation include reductions in unplanned system outages through the use of interruptable loads and customer inconvenience. Thus, cost/benefit analysis, which explicitly considers changes in what the customer is getting, is needed in demand-side planning.

3. Demand-side planners must look at more things. The impacts of demand-side strategies are played out in a complex system of interactions among customers, the utility, and regulators. The complexity of this system makes it more difficult to project the impacts of demand-side programs. Doing so requires much closer integration of several functions within a utility: market analysis, rate design and generation planning and operation.

4. Because demand-side strategies are new to most planners, the percieved uncertainties are greater than with supply-side plans aimed primarily at adding new generation and transmission capacity. Also, uncertainties about customer acceptance and response to demand-side programs bring additional uncertainties to demand-side planning.

In summary, the host of demand-side planning options to consider, the diversity of the impacts and criteria for evaluation, the technical complexities and the uncertainties make the demand-side planner's job especially difficult.

THE LOAD MANAGEMENT STRATEGY TESTING MODEL--OVERVIEW

The purpose of LMSTM is to provide planners with an integrated system for quickly and inexpensively screening and evaluating demand side strategies. The system is designed to evaluate the full range of demand-side options including time-of-day rates, direct control of appliances, thermal and pumped hydro storage, interruptible service, conservation and dispersed generation (cogeneration).

Project History and Status

The LMSTM is the product of a three-year long, EPRI sponsored project conducted by Decision Focus, Incorporated (DFI). Teams of planners from three investor-owned utilities participated intensely in the model's design and development. The three utilities were Carolina Power and Light, Northern States Power, and Public Service of New Mexico. The initial phase of the project produced a prototype model which was reviewed in a series of workshops. Based on extensive industry review and development experience, the model design was refined and the computer code reprogrammed. The final version of the model was tested by using it to analyse several demand management programs being considered by Public Service of Oklahoma (PSO). (An EPRI report describing the PSO case study is forthcoming.)

Several other organizations have been involved in the conversion of the model from a research prototype to the fully tested, documented package that is now publically available. After the PSO test a group of ten "early bird" users was formed to review the documentation, to test the machine compatibility of the computer code and to evaluate the suitability of the product in a variety of settings.

EPRI is now in the process of transferring LMSTM to the electric power industry. The FORTRAN code is available (free to EPRI members) from the Electric Power Software Center and the model can be accessed by telephone through the the EPRI-sponsored TEAM-UP project. Over thirty-five organizations have obtained licenses to use the model and a user's group is being organized to coordinate the activities of the users and provide a forum for exchanging information and designing enhancements. The model is described in detail in EPRI Report EA-2396, The Load Management Strategy Testing Model (April 1982). A Users Guide for the model is also available.

LMSTM Description

The LMSTM simulates utility/customer system operations and evaluates the results of the simulation. User inputs regulate the system simulation model; outputs of the system simulation model guide the cost/benefit evaluation model.

The system simulation portion of the LMSTM captures the dynamic system interactions by integrating four major components: a Supply submodel, a Financial submodel, a Rate Design submodel, and a Demand submodel. (Figure 1 shows the submodels and their principal linkages.)

The Supply Submodel takes capacity expansion plans and demands as inputs and dispatches existing generation capacity and direct load control hardware in a way that minimizes operating costs day by day. This submodel also predicts unplanned system outages based on demand variations, the reliability of individual generating units, and maintenance requirements.

The Financial Submodel takes the cash flows associated with the capacity expansion plan and calculates fixed cost revenue requirements. This submodel also generates a full set of income and balance sheets.

The Rate Design Submodel calculates the hourly prices and demand charges for each customer class based on class demands, embedded (fixed) and variable costs, and a user specified rate calculation algorithm. Prices are adjusted so that expected revenues equal generation costs.

The Demand Submodel simulates hourly system loads for characteristic day types and seasons. It also simulates the short- and long-term demand responses that occur when prices are changed.

The overall function of the system simulation is to estimate on a yearly basis the consequences associated with a demand management strategy. For the customer, for a specified demand management strategy, the model estimates hourly consumption and prices, outages, inconvenience (e.g., no hot water), and the amount of money voluntarily invested in energy-related hardware and building improvements. For the utility, the outcomes estimated include changes in investment (capital requirements), fuel costs, and oil and gas usage.

A total accounting of all system impacts is not in itself sufficient to say whether one demand-side strategy is any better than another. The LMSTM cost/benefit evaluation model (see Figure 2) takes as inputs the system impacts predicted by the system simulation and calculates net benefits.

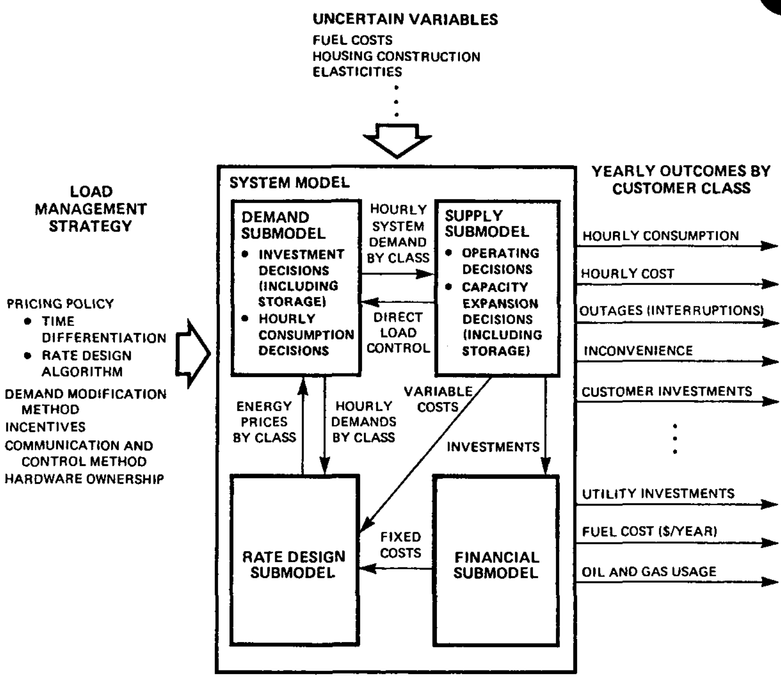

Figure 1. Overview of System Simulation Component

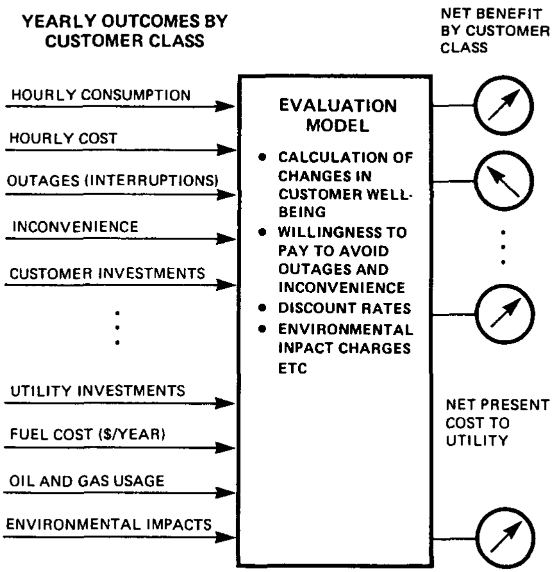

Figure 2. Overview of Cost/Benefit Evaluation Component

Advantages LMSTM Provides Users

LMSTM provides utility demand-side planners with a number of advantages. It is easy to use compared to traditional methods; it has great flexibility to represent a wide range of options and treat uncertainties directly; it distinguishes between cost-effectiveness and cost/benefit analysis and covers a wide range of impacts to obtain a true bottom line for particular demand-side options; and finally it has the technical detail and features necessary to conduct a fair evaluation of alternatives.

Ease in Use

Fully 60 to 90 percent of the effort in any demand management analysis is involved in estimating program impacts. How does a direct load control device change system demands? How does the change in demand change operating costs for the generation system? How do the new generation costs effect rates? These are the questions that currently make demand-side analysis slow and expensive. Once the appropriate data base is created for LMSTM it can answer these sorts of questions in a matter of minutes.

Once the model's data base has been set up and verified, the model will simulate all the impacts of a demand-side strategy quickly and accurately. Twenty year runs of the model with screening level accuracy can be done in about one minute of CPU time on most mainframe computers. This enables planners to explore a much wider range of options and scenarios in reasonable amounts of time. As more promising alternatives are identified, indepth analysis can done with the same model simply by increasing the level of computational accuracy and reporting detail. Even with the highest level of accuracy the run times are less than 5 minutes.

Flexibility

LMSTM has the flexibility to evaluate virtually every demand-side strategy currently being considered, taken singly or in combination, and to treat the many uncertainties prevailent in demand-side planning.

The Rate Design Submodel is designed to simulate a range of utility rate making conventions in calculating changes in rates due to changes in costs. Rates are simulated by customer class, season, day type and hour of the day in order to permit direct assessment of the impacts of cost-based time-of-use rates on loads and customer well being. The model is also capable of simulating seasonal, demand, and interruptable rates. These capabilities are useful because rate options can be a major component of demand-side strategies.

The model also has great flexibility for simulating direct load control or conservation strategies. The direct load control (DLC) capability includes water heater control, air conditioning cycling, pre-heating or cooling, interruptible loads, dual fuel space heating and heat or cool storage. Working in conjunction with the Supply Submodel, the DLC's can be dispatched on an economic basis along with central-station generation and pumped hydro storage. Up to 15 groups of DLC devices can be operated simultaneously.

The model gives users substantial freedom in designing demand-side programs. For example, once the model is set-up, rate structure can be modified at will from non-time-differentiated, accounting-cost-based rates to full marginal-cost-based-rates that vary by hour without changing the data base or submodel interfaces. The value of this built-in assurance of consistency is readily apparent to anyone who has ever tried to coordinate an analysis involving production costing, demand forecasting and rate design.

LMSTM's flexibility is also useful in dealing with the uncertainties associated with demand-side planning. It's designed-in flexibility permits the user to explore the implications of uncertain variables in either a simple sensitivity analysis or more complicated decision tree analysis. Because inputs are easily changed and the model can be run quickly, the user can explore a host of demand-side planning strategies and can identify those that are most robust over a wide range of possible futures.

Considers Both Costs and Benefits

LMSTM has the capability to track a wide range of possible impacts of demand-side programs from both a cost-effectiveness and a cost/benefit perspective. The model calculates changes in the value (benefits) of service (using consumer surplus concepts). It also calculates the cost of outages, direct customer investments, and the cost of inconvenience due to direct load control.

Impacts on system reliability are measured in terms of outages (unserved energy). The cost of outages is expressed in dollar terms by multiplying the total energy unserved due to outage times and the estimated cost per unit of unserved energy. The unit values of unserved energy can vary by customer class. For example, unserved energy to industrial customers may have a high penalty value while interrupting residential customer's water heaters may have a very low penalty value.

The model keeps track of service interruptions so an inconvenience cost can be estimated. For example, the model will keep track of the amount service decreased by air conditioning cycling so we are able to estimate customer impact under several demand growth scenarios or capacity expansion plans.

LMSTM will also keep track of so-called external costs, costs that are not normally allocated to customer classes or even to the utility's customers as a group. These "external" costs include the environmental impacts associated with the operation of power plants (set plant plant) and national security premiums associated with the use of oil. Because the values of these charge parameters can be controversial, this can be a fruitful area for sensitivity analysis.

Finally, LMSTM records costs and benefits by customer class, as indicated by the column of indicators on the right hand side of Figure 2. The costs and benefits of demand-side strategies are often spread unevenly among customers. To answer the question of who benefits and who pays, costs and benefits must be accounted for on a class-by-class basis. Classes are defined by the model user and can be based on demand determinants, such as appliance mix, as well as on rate or price determinants. For example, for purposes of computing net benefits, a residential rate class can be divided into subclasses, such as customers with electric heating and those without.

Appropriate Technical Detail

Designed from the beginning to address demand-side planning issues, LMSTM has a number of technical features not commonly found in traditional planning tools. These features help give LMSTM users more accurate projections of program costs and benefits than they would otherwise have.

Demand-side planning requires a good understanding of the utility's loads. Before the planner can estimate how the demand for electricity might be modified, he must first recognize the major determinants of daily, weekly, and seasonal demand cycles (patterns). The demand submodel within LMSTM is capable of treating the hourly variations in demand (load shapes) at the level of customer classes (e.g., residential or commercial), end uses (e.g.,space heat, water heat, air conditioning), and technologies (e.g., room, central and heat-pump air conditioning). The "end-use" approach presents a data collection challenge for the analyst but the reward is a good understanding of the demand modification potential and much more accurate estimates of program impacts and benefits. To help utilities that are short on end-use load data, we have developed a tool to scientifically combine data from other utilities with whatever is known locally to fill in the gaps.

As discussed above, LMSTM's Rate Design Submodel is intended to address a wide range of rate options and rate making conventions. It provides customer, demand, and energy charges by customer class and rate period. These rates can be based on either accounting cost or marginal cost principles or a mix of the two. The Rate submodel's detail permits the user greater specificity in designing programs and also helps the model provide more accurate estimates of rate-sensitive loads.

The LMSTM production costing (Supply) submodel is one of the most innovative features of LMSTM. It estimates production costs and reliability by day and season considering the probabilistic nature of power plant availability and the chronological nature of hourly loads. Direct load control (DLC) devices are modeled as an integral part of the system. Controllable demands are simulated at the appliance level (e.g., residential water heat) within the customer Demand Submodel, and they are controlled by the utility Supply Submodel. The DLC devices are dispatched in a fashion that minimizes total system operating costs subject to power plant availabilities and the operating characteristics of the DLC devices. The result is more accurate evaluation of DLC benefits than can be obtained by predicting DLC operation (modifying load shapes) and inputting them into a conventional production costing model. Less effort is involved as well. The stochastic (probabilistic) nature of LMSTM's Supply Submodel is also useful in evaluating the impact of demand changes on reliability (system outages) and in evaluating demand-side strategies that entail planned interruption of specified customers under emergency conditions.

The Financial Submodel has two roles in LMSTM. First, it must translate investment costs and the utility's financial structure into required revenues for use in the rate model. Second, it provides detail on the financial implications of demand-side planning alternatives so the value of the alternatives can be assessed from the perspective of the utility's owners. Although LMSTM's Financial Submodel is oriented toward an investor-owned utility financial structure, it has been successfully applied to a publicly-owned-utility financial structure in at least one instance.

LMSTM explicitly considers the feedback loop among loads, costs, and rates. This is important because demand-side options impact each area. Whenever a utility institutes a demand management policy, dynamic feedback occurs between the utility and its customers. This feedback loop occurs because customers change their patterns of demand for electricity in response to the demand management policy. This ultimately results in a change in the cost of electricity generation, as the utility responds to the demand changes by modifying the mix of technologies installed and operated. In turn, these cost changes necessitate alterations in prices when the utility modifies its rates to reflect changes in generating costs. Finally, the feedback loop is closed when these new rates cause further changes in demand patterns. Of course, this feedback is not instantaneous. Lags occur while customers react to the demand management strategy, and further lags occur while the utility reacts to the changes in demand. Evaluation of these feedback loops, however, can greatly improve the accuracy and internal consistency of long term projections of loads, costs and net benefits of demand-side programs.

CONCLUSION

Evaluation of demand-side options presents numerous difficulties and complexities for utility planners. There are a large number of options to consider, there are alternative criteria for evaluation and new measures of impacts, the uncertainties are great, and there are technical complexities that make accurate estimation of impacts difficult.

The Load Management Strategy Testing Model is an innovative EPRI product that will make it easier for demand-side planners in utilities to overcome these problems.

COSTING THERMAL ELECTRIC POWER PLANTS*

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In an earlier paper (1) analyzing the total capital investment requirements and the overall energy cycle efficiencies of electric generating plants, this author noted that the product of these factors was relatively constant for all the energy resources investigated (i.e. total capital investment X net cycle eff $\simeq$ constant). This constancy was striking, since the capital cost and energy analysis data were drawn from many sources, and the technologies varied from proven (coal-fired power plants) to developmental (fusion and solar). The total capital investments from resource development to delivered electric power, varied by a factor of 20, and the overall cycle efficiencies varied by a factor of 17, yet the products of these values for the same annual output were within 25 percent of the average for all electric power systems considered.

While the relative constancy of products was surprising, there is a basic logic supporting these results. The greater the number of steps required to process a fuel from an in-situ resource to delivered electric power, the greater the capital investment requirements. Similarly, the greater the multiplicity of processing steps for fuel, the lower the overall cycle efficiencies in its ultimate conversion to electric power. The opposing trends of these two factors would tend to compensate for each other when multiplied as a product.

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This energy resource utilization reasoning should not be confused with conventional logic, whereby a specific design is optimized by a greater investment to achieve improved performance and efficiency. In this paper, we are dealing with overall resource systems which incorporate optimized steps from the in-situ energy resource to delivered electric power.

In addition, another relationship may be developed whereby the input energy necessary to mine minerals and fabricate equipment, construct the energy resource processing plants, and to construct electric power generating plants can be related to their capital investments. The input energy and capital investment, for example, to construct an oil-fired power plant, are significantly less than the capital investment and input energy to construct a synthetic fuel plant for electric power generation. If the total input energy to build a plant can be related to its total capital investments, it may be possible to forecast the capital requirements of new energy technologies, based upon net energy analysis techniques.

The intent of this paper is to analyze the interrelationships of total capital investments, overall cycle efficiencies, and the net energy analyses (input/output energies) of electric power systems, to determine if there is correlation among these factors. While accuracy in such an analysis is not possible without detail designs, it may be possible to develop approximations helpful in studying the impact of efficiency improvements upon capital investments, and to make preliminary estimates of the capital costs of new technologies from net energy analysis data. If there is an interrelationship among alternative electric power systems, it may be possible to forecast trends in commercializing new technologies based upon price forecasts of conventionally fueled electric power systems.

THE INTERRELATIONSHIP OF CAPITAL INVESTMENT, CYCLE EFFICIENCY AND NET ENERGY ANALYSIS

In a paper analyzing capital investment, net cycle efficiency and net (input/output) energy analysis of 1000-MW thermal electric power plants, Baron (1) noted that the total capital investment, multiplied by the net cycle efficiency, was relatively constant for such resources as oil, coal, synthetic fuels from coal, fission, fusion, and solar energies. Based upon an annual delivered electric power output of 7 X 10^9 kWh/yr (1000 MW, 7000 h/yr), the product of average capital investment and net cycle efficiency for all energy systems is estimated equivalent to $0.25 X 10^9 in 1975 dollars. The capital investment includes not only the capital cost of the power plant and transmission system, but also the capital investment for exploration, transportation, mining, processing and reprocessing of all fuels necessary to deliver 7 X 10^9 kWh/yr to the load centers.

King (2) expanded on this relationship to incorporate net energy analysis estimates along with capital investments and net cycle efficiencies. Using King's mathematical approach and Baron's 1975 figures, the following equations can be derived:

for 1000-MW capacity delivering 7×10^9 kWh/yr in 1975 dollars

Capital Investment × net cycle efficiency = $0 25 × 10^9 or

$$\text{GNP (1975)} \times \text{NCE} = 0\ 25 \times 10^9 \qquad (1)$$

The total consumption of energy in the U S in 1975 was 47,400 Btu/dollar of GNP [3] or 4 7 kWh of electricity/dollar at an overall heat rate of 10,200 Btu/kWh Therefore

$$\frac{\text{Total Energy}}{\text{GNP (1975)}} = \frac{4\ 7\ \text{kWh}}{\text{Dollar}}$$

Rearranging this equation

$$\frac{\text{Total Input Energy}}{\text{Total Electric Output}} \times \frac{\text{Total Electric Output}}{\text{GNP}} = \frac{4\ 7\ \text{kWh}}{\text{Dollar}}$$

for 1000-MW, total electric output

$= 10^6$ kW $\times 7 \times 10^3$ h/yr $\times$ 30 yrs

$= 210 \times 10^9$ kWh (assuming 80 percent capacity factor over plant life)

By definition,

$$\frac{\text{Total Input Energy}}{\text{Total Electric Output}} = \text{Energy Subsidy Fraction or ESF}$$

then

$$\frac{\text{ESF}}{\text{GNP}} = \frac{4\ 7}{210 \times 10^9} = 0\ 022 \times 10^{-9} \qquad (2)$$

Combining equations 1 and 2

$$\frac{\text{ESF}}{\text{GNP}} \times \text{GNP} \times \text{NCE} = 0\ 022 \times 10^{-9} \times 0\ 25 \times 10^9, \text{ or}$$

$$\text{ESF} \times \text{NCE} = 0\ 006 \qquad (3)$$

Since there have been a number of studies in recent years on the energy subsidy fraction (or net energy analysis) and net cycle efficiences of coal, oil, nuclear, and synthetic-fueled power plants, it will be possible to test the validity of equation 3 Equations 1 and 3 can be rearranged to approximate the total capital investment of any 1000-MW thermal electric power plant

From equation 3

$$\text{NCE} = \frac{0\ 006}{\text{ESF}}$$

Substitute into equation 1

$$\frac{\text{Total Capital Investment (1975)}}{1000\ \text{MW}} = \frac{\$0\ 25 \times 10^9}{0\ 006}\ \text{ESF}$$

$$= \$42 \times 10^9\ \text{ESF} \qquad (4)$$

Since a great many studies have been made in 1980 dollars, the capital investments have been corrected by the Handy-Whitman Construction Price Index between 1975 and 1980 which calls for increases of about 1 50 Therefore, equation 1 would be corrected as follows

$$\frac{\text{Total Capital Investment (1980)}}{1000\ \text{MW}} = \frac{1\ 5 \times 0\ 25 \times 10^9}{\text{NCE}} = \frac{\$0\ 38 \times 10^9}{\text{NCE}} \qquad (5)$$

REVIEW OF NET ENERGY ANALYSIS DATA OF PRESENT-DAY TECHNOLOGIES FOR ELECTRIC POWER GENERATION

Since the government legislated in 1974 that net energy analyses should be conducted on technologies approaching commercialization, there have been extensive studies dealing with this subject. Herendeen, Bullard, and their associates at the University of Illinois, have developed a large body of data on embodied energy in capital goods which serves as a basis for many net energy analyses. Pilati (4) has made extensive use of this information for his net energy analyses. While other investigators (5-7) worked with this data, they have also modified some values and the process approach. Baron (1) worked with input/output energy data from various sources and mineral production industries to develop his data on the net energy analysis of electric power systems.

These various studies have been recalculated according to the definitions described in the previous section. The ESF (Energy Subsidy Fraction) is the ratio of the total input energy for all capital investments (as Btu or KwH thermal) to the total output of electric energy (as Btu or kWh electric). The NCE (Net Cycle Efficiency) is the ratio of the net output of electric energy (Btu or kWh electric) to the total input of energy resources extracted from the environment not only as fuel, but also for operating energies.

Operating energies in this definition includes all the auxiliary energy necessary to operate all the mining, processing, transportation, and electric generating steps in the overall utilization of the energy resource. The net output of electric energy as defined in this paper is the delivered electric power less the electric energy equivalent consumed as input to the capital energy for the total power cycle.

Capital energy is the equivalent electric power consumed in manufacturing all the equipment, constructing the plant, and the installation of equipment. The capital energy is annualized over 30 years and subtracted from the electric output. This correction to delivered energy is small for high-intensity energy resources (oil, coal, nuclear), but can be important for solar energy and other options which consume a significant quantity of capital energy.

Table I summarizes the ESF and NCE for present commercial and near-term commercial technologies for electric power production. The most comprehensive study of net energy analysis of electric power systems was conducted by Pilati (4) based upon University of Illinois data. The petroleum-to-electric power cycle was analyzed by Pilati but was not included, because it is based on energy requirements for developing new deep-well oil fields in the U.S. rather than the present relatively shallow wells now operating in the Middle East or the U.S.

The product of ESF and NCE values in Pilati's studies for electric energy alternatives confirm the expected value of 0.006. The net cycle efficiencies vary from a high of 38 percent for low-Btu coal gasification with a combined gas turbine-steam turbine cycle, to a low of 17 percent for synthetic-fuel steam cycles. Considering the significant variation in power cycles, nuclear, coal, and synthetic fuels, the product of ESF and NCE remained fairly constant.

Table I also summarizes other net energy analysis studies. Baron's results have a greater range in values because the data was drawn from different input/output energy references and data sources, and therefore reflects these variations. Nevertheless, considering the diversity of information, the product of ESF and NCE is surprisingly constant. The last column includes other sources of net energy

TABLE I

ESTIMATES OF ESF X NCE CONSTANTS FOR PRESENT TECHNOLOGIES

	Pilati (4)			Baron (1)						
SYSTEM	ESF	NCE	ESF x NCE	ESF	NCE	ESF x NCE	ESF	NCE	ESF x NCE	See Reference
Oil-Power	Not Applicable			0 020	0 27	0 005	0 026	0 278	0 007	(7)
Coal-Power	0 020	0 306	0 006	0 020	0 32	0 006	0 026	0 298	0 008	(5)
							0 023	0 283	0 007	(7)
Coal-HiBtu - Power	0 040	0 175	0 007	0 044	0 175	0 008	0 060	0 170	0 010	(7)
Coal-Combined Cycle	0 015	0 383	0 006	—	—	—	—	—	—	
Coal-SRC-Power	0 028	0 165	0 005	0 046	0 194	0 009	0 046	0 169	0 008	(7)
Oil Shale-Refined-Power	0 032	0 178	0 006	—	—	—	—	—	—	
Nuclear-LWR	0 030	0 226	0 007	0 036	0 25	0 009	0 030	0 272	0 008	(5)
							0 030	0 26	0 008	(6)

TABLE II

CAPITAL INVESTMENT IN FUEL FOR 1000-MW THERMAL POWER PLANTS

Capital Investment in Fuel / Total Capital Requirements				Capital Investment in Facility / Total Capital Requirements
Fuel	Baron (1) 1970 to 1980	Bankers Trust (8) 1980 to 1990	Average	(By Differences)
Oil	0.30	0.50	0.30	0.70 (1980 & Before)
			0.40	0.60 (Post-1980)
Coal	0.16	0.23	0.20	0.80
LWR	0.04	0.10	0.07	0.93

analysis with results that are still within the range of the expected value of 0.006. Both the Colorado Energy Research Institute (7) and the Institute of Energy Analysis (6) have made extensive studies in net energy analyses, and their results are within the expected range of 0.006. The intent of this analysis is to compare the calculated capital investment for alternative energy systems assuming 0.006 while recognizing that there may still be some variations in the "assumed constant."

COMPARISON OF CALCULATED CAPITAL INVESTMENTS REQUIRED FOR ALTERNATIVE ELECTRIC POWER SYSTEMS

There is a significant difference between the "price" of a fuel and the "cost" of a fuel, particularly oil and gas. The exploration and development cost to the producer of Middle East oil has been reported to be about $1/bbl, while the price to the consumer on the world market is about $30/barrel. Developing new fossil reserves keeps increasing as it becomes necessary to develop deeper wells and mines, to search and develop wells far at sea, and go to more costly exploration techniques. Therefore, the capital investment and the input energy required to develop new reserves will rise as time goes by because of the increasing cost to the energy producers.

Baron (1) analyzed the capital requirements to develop oil, coal, and uranium fuels for electric power generation based upon cost experience in the 1970s. These costs include exploration, development, refining, marketing, transportation of oil, coal and gas fuels, as well as the enrichment, fabrication, and reprocessing of nuclear fuels. Recently, Bankers Trust Company (8) made a detailed study of capital requirements for energy in the 1980s. In this study, they estimated the costs in both current and constant dollars for developing new reserves of oil, gas, coal, and uranium fuels for the 1980-1990 period.

Table II summarizes the ratio of capital investment in fuel to the total capital requirements for oil, coal, and nuclear, using Baron's (1) and Bankers Trust (8) cost figures. Not surprisingly, the capital requirement for oil development is significantly greater than for coal and nuclear. The investment for energy calculated from the Bankers Trust information reflects the more costly investments for future energy. Since present-day commercial electric power plants will draw on the reserves developed in the 70s and 80s, the values are averaged in this analysis.

By means of equations 3 and 5 and the data from Tables I and II, it is possible to estimate power plant capital investment and to compare these calculated values with estimates prepared for similar plants from design studies. The figures in Table I give the energy subsidy fraction or the total energy investment in the capital construction of the total energy cycle. Using the correlation in equation 3 where

$$NCE = \frac{0.006}{ESF}$$

the calculated net cycle efficiency is used to estimate the total capital investment from equation 5. The ratios in Table II are used to separate capital investment in fuel development from the total capital investment. After deducting capital investment in high-voltage transmission systems, the net results reflect power plant capital investment, with or without using synthetic fuels or oil shale, depending upon the cycle under consideration.

Table III summarizes results of these calculations and compares the calculated investments for power plants or synthetic fuel plants with the estimate from the literature using a 1000-MW power plant capacity. In the cases of solar, thermal, and photovoltaic power plants the ESF estimates are for plant capacities much greater than 1000-MW in order to deliver 7 X 10^9 kWh/yr. The ESF for coal and nuclear plants is taken from Pilati's calculations with the exception of the SRC liquid plant, which appears to be at variance with his other synthetic fuel values and the other reference data. The ESF figure for long-term alternative energy systems, such as fusion, liquid-metal fast breeder reactor (LMFBR), and solar energy, were taken from Baron's calculations. While there is a large body of references for 1980 power plant capital investments for alternate energy resources, the reference costs were drawn primarily from the World Bank, Department of Energy (DOE), and Bankers Trust reports for fossil, nuclear, and synthetic fuels plant costs, and the generally estimated capital costs for LMFBR, fusion, and solar energy plants as presently conceived.

Table III compares calculated capital investments for commercial oil, coal, and light water reactor (LWR) power plants with estimates by the World Bank (9). The derived equations give a good correlation within a 10 percent range for these commercial plants. Since these electric power systems technologies are well developed, the estimated costs are typical and compare well with the calculations. The [illegible] (20) recently estimated the 1980 costs for a 1000-MW [illegible] nuclear power plant at $1505/kW for normal lead-time and $1685/kW for protracted lead-time in plant construction. These values compare well with the World Bank estimates and the calculated figures using the proposed correlations.

The synthetic fuels program in the U.S. comprises reasonably well-known technology, but construction has not advanced to any large-scale commercial designs. The investment in synthetic fuels plants was estimated by deducting the power plant costs from total investment cost. The calculated costs in Table III, shown in 1980 dollars, from coal-

TABLE III

COMPARISON CALCULATED INVESTMENT (1980 DOLLARS) BY NET ENERGY ANALYSIS FOR DELIVERING 7 x 10^9 KW HRS/YR THERMAL ELECTRIC POWER PLANTS

Power System	ESF	ESF Reference	Total Capital Investment (Equation 5)	Total Fuel Investment *(Table II)*	Calc Power Plant *Investment**	Calc Syn *Fuel Invest*	Literature *Estimate*	Reference
			x 10^9 Dollars	x 10^9 Dollars	x 10^9 Dollars			
Oil-Power	0 020	Table I	$ 1 27	$0 38	$ 0 79	—	$ 0 8 x 10^9	(9)
Coal-Power	0 020	Table I	1 27	0 25	0 92	—	$ 1 0 x 10^9	(9)
Nuclear-LWR	0 030	Table I	1 90	0 13	1 67	—	$ 1 6 x 10^9	(9)
Oil Shale-Power	0 032	Table I	2 02	0 20	0 80	$28 000/ bbl/day	$20-30 000/bbl/day $22 000/bbl/day	(10) (18)
Coal-HiBtu-Power	0 040	Table I	2 53	0 51	0 60	$40,000	$40-50,000/bbl/day $37 000/bbl/day	(10) (18)
Coal-SRC-Power	0 046	Table I	2 92	0 58	0 80	$45 000	$60-70,000/bbl/day $40 000/bbl/day	(10) (18)
Coal-Combined Cycle	0 015	Table I	1 00	0 19	0 40	$10 000	$15 000/bbl/day	(18), (19)
LMFBR	*0 040*	*(1)*	*2 53***	—	2 43**	—	$ 2 2 x 10^9	(11) (1), (13)
Fusion	0 044	(1)	2 79**	—	2 69**	—	$ 3 0 x 10^9	(1)
OTEC	0 150	(15)	9 5	—	9 4	—	$10 0 x 10^9	(16)
Solar Thermal	0 157	(12)	10 1	—	10 0	—	$12 5 x 10^9	(17)
Photovoltaic	0 256	(12)	16 6	—	16 5	—	$12-30 x 10^9	(9), (17)

*These calculations of invested capital cost of the thermal electric power plant include a credit of $0 1 x 10^9 estimated for high voltage transmission costs associated with each *1000-MW plant This is an average value considering the fact that some units will connect* into existing transmission systems, and some units will require new transmission lines

osts for these systems are low and have been included in the calculations of ESF The ated capital cost of the power plants will be about 5% lower if fuel costs are not ed derived synthetic fuels appear to be on the low side compared to estimates by Bankers Trust (10), but compare well with DOE (18) estimates. The referenced DOE estimates were in 1978 dollars and were inflated 20 percent to correct to 1980 dollars. The spread in estimates is probably due to the spread in calculated ESF, which is reflected by the range in values shown in Table I. The calculated capital cost for low Btu gasification is much lower than literature estimates which may be due to the value of ESF (0.015) being slightly on the low side. A 10 percent increase in the ESF value for synthetic fuels will increase the calculated capital costs by 20 percent. An ESF of 0.018 for a combined-cycle power plant based on low-Btu gas from coal would give a closer check to the literature estimates. The value of ESF for oil shale (0.032) results in synthetic fuel plant costs that compare well with the literature.

Probably the greatest uncertainty in power plant costs is in the long-term energy options of LMFBR, fusion, and solar energy. The fuel costs for both LMFBR and fusion are small and have been rolled into the capital investment calculations (less than 5 percent of power-plant capital cost can be attributed to fuel costs for both these systems). Thermal and photovoltaic solar energy power plants are not designed to operate 7000 h/yr even with energy storage. The ESF estimates in Table III were based on the design capacities greater than 1000 MW that deliver the equivalent of 7×10^9 kWh/yr. The OTEC solar energy power plants can be designed to operate 7000 h/yr so that the ESF for OTEC is for a 1000-MW capacity power plant.

It is not surprising that the calculated power plant costs vary about 25 percent from the costs in the literature for LMFBR, fusion, and solar energy. ESF values are reflected by present designs for long-term energy systems. ESF (0.040) of LMFBR is based on a plant design resulting in capital costs of 30 to 40 percent greater than a LWR. A recently proposed design (14) for LMFBR, reported to have a capital cost equal to LWR, probably has an ESF value close to LWR of 0.030. Considering the developmental nature of these technologies and the probable evolution of their designs, the calculated values are within 25 percent of design estimates and tend to confirm the validity of the derived equations.

The significance of the results summarized in Table III is the predictability of the capital costs using the developed correlations in spite of the large range of ESF value (0.015 to 0.256). The accuracy of the prediction is far better for commercial power plants, since their designs are better defined. As expected, the variations become greater as the energy technology becomes more developmental. It should also be noted that if the product of ESF X NCE was not relatively constant at 0.006, any significant change to such values as 0.004 or 0.008 would give calculated capital costs far below or far above literature estimates. If there is a variation in the value of 0.006, it is likely to be within a much smaller range.

COMPARISON OF TOTAL GENERATING COSTS FOR ALTERNATIVE ELECTRIC POWER SYSTEMS

Using the relationship for capital requirements developed in previous sections, it is now possible to estimate and compare the total generating costs for the alternate electric power systems. Obviously, the fuel-development capital investment used in this study is a fraction of fuel market price, since it neither includes operating labor co maintenance cost, nor the market factors that cause price fluctuation with fuel prices. If one compares the fuel investment cost information in Table IV, the 1980 market "price" for oil was five times greater than the fuel investment cost, while eastern coal "prices" were about four times greater. The fuel "price", of course, includes maintenance and operating labor costs associated with fuel production.

Total generating costs, as summarized in Table IV, are based on the total capital investment in facilities and fuels development (mining to power delivery) as well as an estimate for maintenance and operation costs of power plants and synthetic fuel plants. The annual maintenance and operating costs of the operating plants shown in Table IV were estimated at 10 percent of the annual charges for capital investment in power plants, and at 15 percent for synthetic fuel plants. The only exception is in the combined-cycle case, which includes an additional maintenance cost associated with gas turbine operations.

For annualizing the capital investments, a 15 percent fixed-charge rate was used for the facilities and 15 percent as a return-on-investment for the fuels development. The 15 percent fixed-charge rate on facilities covers both interest and depreciation, while the 15 percent on fuels development is for interest only. Interest charges should be higher for fuels than facilities because of the greater risks involved. These values can be varied by prorating the values in Table IV to study the effect of different charges and different interest rates.

Since there is a direct relationship between total capital investment and ESF (Energy Subsidy Fraction), the 15 percent annual carrying charge with the assumed M&O costs gives the generalized relationship of:

Total Generating Costs (¢/kWh) = 143 ESF (

Equation 6 is based on the investment in facilities and fuels in 1980 dollars. It does not consider the effect of market forces, labor costs, and transportation on energy resource prices. A 1000-MW LWR power plant, having an ESF of 0.030, will have a total generating cost of 0.030 X 143 or 4.3¢/kWh of which fuel investment will account for 0.3¢/kWh (Table IV). If all the operating costs associated with the fuel cycle were included in the market price for uranium,

TABLE IV

1980 GENERATING COSTS
(BASED UPON CAPITAL INVESTMENT REQUIREMENTS)
15% Annual Carrying Charge for Capital and Fuel Investment

System	ESF	Capital ¢/Kwhr	Fuel ¢/Kwhr	M&O ¢/Kwhr	Total Generating Costs ¢/Kwhr
Oil-Power	0 020	1 7	0 8	0 2	2 7
Coal-Power	0 020	2 0	0 5	0 2	2 7
Nuclear-LWR	0 030	3 6	0 3	0 4	4 3
Oil Shale-Power	0 032	3 7	0 4	0 5	4 6
Coal-HiBtu-Power	0 040	4 1	1 1	0 5	5 7
Coal-SRC-Power	0 046	4 8	1 2	0 7	6 7
Coal-Combined Cycle	0 015	1 6	0 4	0 6	2 6
LMFBR	0 040	5 2	—	0 5	5 7
Fusion	0 044	5 8	—	0 6	6 4
OTEC	0 150	20 0	—	2 0	22 0
Solar-Thermal	0 157	21 0	—	2 1	23 1
Photovoltaic	0 256	35 0	—	3 5	38 5

the actual fuel cost would be 1¢/kWh, rather than 0.3¢/kWh. The actual generation costs would then be 5¢/kWh based upon 1980 dollars for total capital investments.

Calculations of the generating costs must, in reality, be based on the market price for fuel, and therefore Fig. 1 was developed to show how fuel market prices impact alternate electric power systems. Since coal prices will determine the competitiveness of alternate energy systems, Fig. 1 includes the effect of variations in the levelized price of coal on total generating costs.

Using a coal-fired power plant, with levelized coal price at $\$2/10^6$ Btu, the total generating costs (Fig. 1) would be 4.5¢/kWh. At the same coal price, a combined cycle using low- or medium-Btu fuel (coal c.c.) would give a total generating cost of 4.0¢/kWh (Fig. 1). Using high-Btu synthetic gas or coal-derived liquids as a fuel, power generation cost is consistently greater than for a direct-fired powerplant if the price of coal were the same. To generate power from synthetic fuels would require a life-time-levelized coal price of about $\$3/10^6$ Btu less than coal used for direct-fired power generation.

As noted in Fig. 1, a 1000-MW LWR based upon a levelized market price for fuel of 1¢/kWh will generate power at 5¢/kWh. This cost would be competitive with coal at a levelized price of about $\$2.50/10^6$. A 1000-MW LMFBR plant would have a total generating cost competitive with a levelized coal price of $\$3/10^6$ Btu, while a fusion power plant would be competitive at $\$4/10^6$ Btu. With oil in 1980 at \$26/bbl, Fig. 1 shows direct-fired coal power, combined cycles, LWR, LMFBR, and fusion to be more economic alternatives.

The solar energy option, as presently conceived, will only be competitive when levelized coal prices are over $\$8/10^6$ Btu. While the coal market price will rise as it becomes the primary fuel for power generation, the solar energy option calls for new designs that will achieve lower ESF. Many of the research programs for solar energy are geared to lowering costs, which means using less-energy-intensive materials, as well as achieving more efficient operations.

CONCLUSIONS

The near constancy of the product of ESF and NCE at 0.006 for commercial and near-commercial thermal power plants is confirmed by reviewing the data from various independent studies. The striking feature about this relationship is that it is not directly capital-cost dependent, but rather dependent on the plant design, which requires a knowledge of plant materials, operating energies and conversion efficiencies. The constancy of the ESF X NCE product results in good cost predictions for new energy technologies such as breeder, fusion and solar energy.

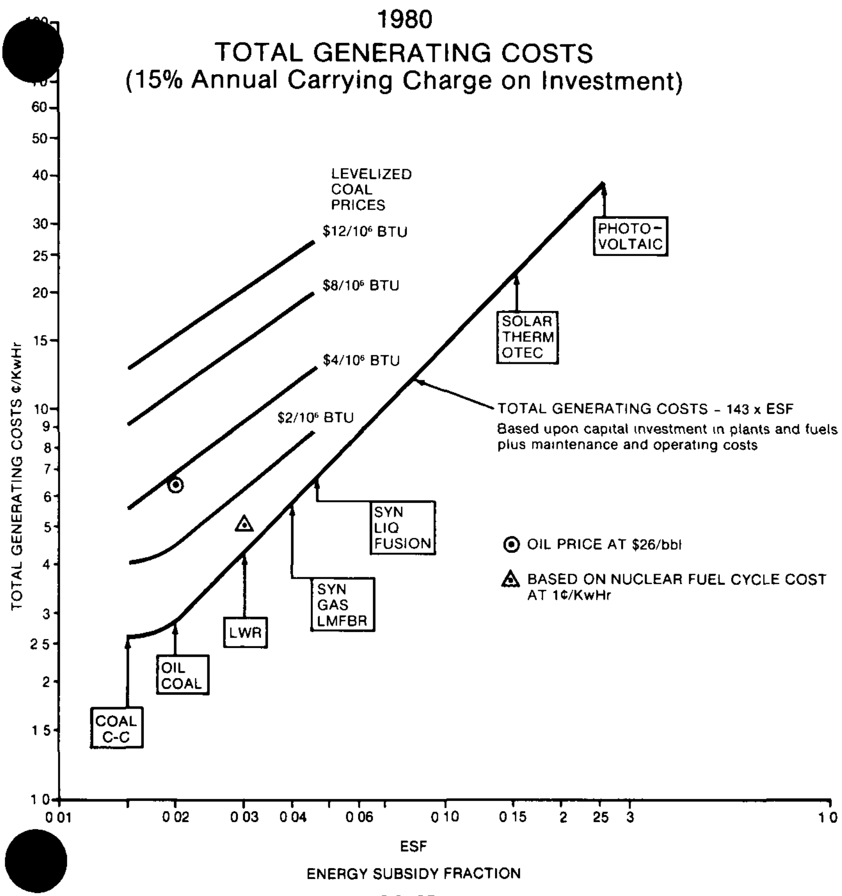
1980
TOTAL GENERATING COSTS
(15% Annual Carrying Charge on Investment)
LEVELIZED
COAL
PRICES
$12/10⁶ BTU
$8/10⁶ BTU
$4/10⁶ BTU
$2/10⁶ BTU
PHOTO-
VOLTAIC
SOLAR
THERM
OTEC
TOTAL GENERATING COSTS - 143 x ESF
Based upon capital investment in plants and fuels plus maintenance and operating costs
SYN
LIQ
FUSION
SYN
GAS
LMFBR
LWR
OIL
COAL
COAL
C-C
OIL PRICE AT $26/bbl
BASED ON NUCLEAR FUEL CYCLE COST AT 1¢/KwHr
TOTAL GENERATING COSTS ¢/KwHr
ESF
ENERGY SUBSIDY FRACTION

FIGURE 1

In addition, the constancy of the product of total capital investment and the NCE of a specific energy system also gives a fairly good correlation for predicting capital costs for thermal power plants and their related synthetic fuel plants. Since capital investments in facilities are time dependent, predicting capital costs beyond 1980 would require corrections to the correlations for capital investments in other periods. However, the 1980 correlation of capital investment and net cycle efficiency appears to ho up very well considering the diversity of technologies an the range in predictable costs.

Calculating generation costs based upon these derivations, gives results that compare well with other studies for similar energy systems. By means of these relationships, it is possible to make a "first cut" estimate of capital costs and generating costs for any thermal electric power system provided the energy input values or the overall net cycle efficiencies are known. Obviously, these simplified relationships cannot be used for detailed cost estimates which depend upon specific site data regional factors, productivity, transportation, and market factors. However, for first-order cost estimates of diverse electric power systems, the correlations in this paper appear to give good results.

While ESF is not expected to change much for mature technologies such as oil, coal, and LWR power plants, developing technologies should have significant changes as designs are better defined. ESF values for developing technologies may increase or decrease, depending upon design evolution and its impact on cycle efficiencies. Clearly, improvements in costs for an energy system will be achieved by reducing the design value of ESF and by increasing overall-system NCE. Solar energy, for example, will become a competitive energy option only if the present values of ESF (over 0.15) can be significantly reduced. Solar energy research is now moving toward lowering ESF and increasing NCE.

Net energy analysis investigations were initially implemented in order to determine on an accounting basis how much energy must be consumed before the final product (electric power) is delivered to the load centers. This information has been valuable to energy planners evaluating the merits of alternative energy options for commercial development. This paper has extended the value of net en analysis data by showing it can be utilized to predict i vestment costs and generating costs of alternative energy systems, whether they are commercial or developmental in nature. Most important, there appears to be a predictable interrelationship among all energy options if comparisons are based on the total energy cycle of each option. These interrelationships will permit investigators to estimate approximate costs of any energy option utilizing only the net energy analyses calculations for the system. This could be of significant value to investigators in the energy field.

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WHY IS THE PERFORMANCE OF ELECTRIC GENERATING UNITS DECLINING

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I. INTRODUCTION

In these days of exorbitant fuel prices and prohibitive construction costs, utility managers and regulatory commissioners throughout the country are turning their attention to the operation of existing generating plants. The questions they are asking are: (1) to what extent can performance improvements offset high fuel prices and forestall the need for new costly capacity, and (2) if commissions adopt incentive programs, what is a reasonable conceptual basis for determining performance standards and what are appropriate numerical standards?

At the same time, the electric utility industry is faced with declining performance of its large baseload coal units. Using two traditional measures of generating unit performance, namely, annual equivalent availability and annual heat rate, we traced the performance over the period 1970-1977 (the latest year for which we had unit data) of a sample of coal units built prior to 1970. We found that, for this sample, equivalent availability dropped an average 1.5 percentage points per year between 1970 and 1977, from [illegible] percent in 1969 to 64 percent in 1977. For these same units, heat rates were rising by some 75 Btus per year from 9,070 to 9,600. So not only were these units becoming less and less available, but when they were available they were requiring more and more fuel to generate each kilowatt-hour.

The performance losses from decreased unit efficiency can be significant. For example, in places where losses in coal-fired generation are replaced by oil-fired generation (elsewhere on the system) every 1 percentage point decline in equivalent availability for a single 500 megawatt unit costs ratepayers over $1 million dollars per year. For our entire sample of 80,000 megawatts, the decline between 1970 and 1977 in availability is also equivalent to 20 new 500 megawatt units. At current construction costs, the industry would have to raise $8 billion to replace these efficiency losses. Put simply, the utility industry--already desperately strapped for construction funds--is forging ahead building new plants, while a significant portion of its existing base-load coal capacity is sitting idle or running poorly. Inefficiency is costing both the consumers and the stockholders money.

II. THE NERA METHOD OF EVALUATING PERFORMANCE

NERA developed two econometric models of generating unit performance: one to explain annual unit equivalent availability and one to explain annual unit heat rate. Variables used to explain unit performance included engineering design, age, size, vintage, fuel quality, and financial characteristics, age, size and vintage. The two models were based on data from a sample of large coal units. The sample was limited to units larger than 200 megawatts, and built between 1960 and 1974. There were 171 such units, and these were operated by 57 different utilities.

For the first model, historical data on equivalent availability of the units for the period 1969-1977 were derived from two EEI/NERC data tapes. Incidently, a comparison of the tapes, one of which is merely an updated version of the other, indicated great inconsistencies in the data. Therefore, before using the data, we resolved the inconsistencies, in many cases with the help of utility plant managers.

For the second model, historical data on net heat rate of the 171 units were not publicly available. But, we were able to compute gross annual unit heat rates for the period 1969-1977, using a variety of published data sources.

Once we had data for the two performance measures that we were trying to explain, we consulted various published performance studies and talked with numerous engineers around the country to determine which characteristics heavily affect generating unit performance. Our inquiry in this area indicated that certain built-in engineering features and the quality of coal were two important factors in explaining equivalent availability and heat rate. The list of other relevant factors was longer than the list of factors for which data was obtainable. For coal characteristics, we were able to obtain data on heat, sulfur, ash and moisture content. Data on other coal characteristics, such as ash softening temperature, viscosity and grindability, which are important in explaining performance, could not be obtained. For the built-in engineering features, we were able to obtain data on boiler design, boiler manufacturer and turbine-generator manufacturer. Data on design characteristics such as heat release rate were difficult to acquire.

The results from the model of equivalent availability suggest that the factors we were able to include in the model do indeed affect this performance measure. For example, coal quality had several effects on equivalent availability: the higher the sulfur content of the coal, the lower unit equivalent availability; the same is true of the moisture content. The model results also suggest that a unit fueled by coal which is 1 percent higher in both moisture and sulfur content (other things being equal) would have an availability roughly 4 percentage points lower than it would if it were burning higher quality coal. The lower the heat (Btu) content of the coal, the lower the availability. The only coal characteristic which does not appear to affect equivalent availability is ash content. However, this is not a surprising result since the softening temperature (a variable for which we do not have data) is consid more important in affecting unit availability.

The results of the first model also suggest that built-in design characteristics have a systematic effect on availability. For example, units with balanced draft boilers have equivalent availabilities some 5 percentage points better than those with positive pressure. Dry ash boilers are 4 percentage points better than cyclone and recirculating boilers are 6 percentage points better than once-through boilers. Generating units with boilers manufactured by Babcock & Wilcox showed slightly higher availability. Also units with GE turbine generators showed higher availability: this could be due to differences in the design of the turbine and generator but the data necessary to make that determination were unavailable at the time of the study. So, a balanced draft, recirculating boiler with a GE turbine-generator could perform 13 percentage points better than a unit without these design and manufacturing characteristics. However, as noted above, the analysis does not take the cost of the equip ment explicitly into consideration.

To illustrate the effect that changing some factors may have on equivalent availability, consider the following example. Suppose we have a 600 megawatt unit that was built in 1970 which is "now" four years old. It has a balanced draft, recirculating boiler manufactured by Babcock & Wilcox and a Westinghouse turbine-generator. Currently, the unit is burning coal with a heat content of 12,000 Btus per pound, 3 percent sulfur, 10 percent ash and 8 percent moisture. The expected equivalent availability of that generating unit would be 76 percent. Now suppose that the unit had been built with a positive pressure rather than a balanced draft boiler. The expected availability of such a unit would be 71 percent. Suppose, in addition, that the unit had a once-through rather than a recirculating boiler; expected availability would be still lower, 65 percent. Similar calculations could be made for the other explanatory factors.

The second model--the heat rate model--produces similar results with respect to engineering features and coal quality factors. For example, the heat rate model suggests that supercritical generating units have better (i.e., lower) heat rates than subcritical units. Lower levels of ash and moisture coal improve the heat rate.

What was surprising in both models was that after incorporating many engineering and coal quality characteristics, there was still a strong decline in performance over time. The effect of this declining trend was seen in the strong effect of unit "age" in both models. Neither the engineering factors nor the coal quality factors eliminated the effect of age. These factors explain differences in performance among the various units, but do not explain why the performance of all units has declined over time.

III. THE DECLINING TREND OF PERFORMANCE OVER TIME

Why is the performance of electric generating units declining? We tried two explanations for the decline in equivalent availability over time. First, as discussed above, we hypothesized that the decline in unit equivalent availability is made up of two components: the age of the unit and the vintage of the unit, defined as the year in which it was built. Were units built in 1967 systematically better or worse than those constructed in 1969? Keep in mind that the vintage of each unit remains the same over time whereas the age increases with each passing year. Our analysis showed that the earlier built units performed better, given their age, than the units built later on (in technical jargon, vintage had a strongly negative coefficient). Age, as might be expected, also adversely affected performance over time. So while new units may perform better than old units, they do not perform better than the old ones did when they were first built.

If age is the true explanation for the decline in performance over time, various interpretations of the aging effect could be offered. One rather pessimistic theory would be that things just naturally get worse and worse. Another theory would be that the utility industry, as a whole, has bought less and less reliable equipment over the years and whose performance has worsened over time.

However, it would be hard to find an engineer who believes that a decline as large as 1.5 percentage points a year is an inevitable effect of aging. The engineers we consulted agree with most of the results of the model. But they did not accept the size of the downward time trend as an inevitable effect of aging. With sufficient maintenance, they explained, a generating plant should be able to perform with minimum deterioration over the years. And yet, all of the units have deteriorated.

If utilities are buying less reliable plants and then letting the generating units deteriorate, it is easy to guess that an economist would turn to financial explanations. This is what we tried next.

Throughout most of the 1970s, the earned rate of return on equity of utilities declined slightly. At the same time, required returns rose. Thus, the industry's earnings were eroded as the difference between required and earned returns widened. Because data were unavailable for required returns on equity, we could not use the difference between earned and required returns as the financial explanatory variable. Instead we adjusted earned returns by the utility bond rate. The movement in the bond rate is generally assumed to track that of required returns.

NERA computed an adjusted rate of return on equity by subtracting the bond yield from the earned rate of return on equity for the utilities in the sample. Now, because adjusted returns showed a time trend, these data should help explain a time trend in the EEI/NERC unit availability data. The fact that a trended variable correlated strongly with the declining trend in equivalent availability did not surprise us. We, therefore, used a stronger test to determine if the earned rate of return was a significant factor in explaining unit equivalent availability apart from its ability to explain the strong time trend.

We calculated the moving average of the differences between the earned return for each utility in our sample, and the bond yields for the three previous years. The idea here was that in any given year (i.e., removing the time trend completely), the availability of units would reflect the earned net return on equity of the operating utility in the three previous years.

The results were very strong. In every year from 1970 to 1977, the availability of generating units was affected by the previous three years' (adjusted) return on equity. The higher the returns, the higher the subsequent availability. In every year, looking across all coal units in the United States, unit performance was correlated with the previous years' returns of the operating utility. The effect was strongest after 1974, the year in which the required net returns on equity jumped because of increased risks. In contrast, the effect of the age of a unit was barely significant, dropping to a decline of 0.8 percentage points per year. Moreover, the effect of vintage also decreased. However, the impact of the engineering factors remained the same.

There was the possibility that we had a chicken and egg situation. If plants perform poorly (i.e., low availability), a utility has to spend more money on purchased power, and more dollars should be devoted to maintenance. If these things happen, the utility's rate of return would suffer. This idea is not the reverse of the above idea: one says declining availability is caused by past financial difficulties; the other says low availability causes present financial problems. We tested the latter idea and it was not supported: the rate of return in a given year was not related to current availability in any systematic way.

This suggests that if a utility's earnings are squeezed, poor unit performance follows--although it takes a couple of years for this to become apparent in lower equivalent availability and higher heat rate, that is, higher costs to the ratepayer. Anyone who has been responsible for a budget or a business decision knows that this is what often happens in any industry: earnings fall, maintenance is skimped and equipment becomes less productive. Doubters are referred to the example of the New York City transit system:

> The Metropolitan Transportation Authority of the State of New York "literally stopped preventative maintenance in 1975," when the city's fiscal crisis hit, says City Council President and MTA board member Carol Bellamy. The results were stark: The number of serious breakdowns en route rose to 12,291 in 1977 and tripled to an estimated 36,000 this year; and the number of miles traveled by the average subway car before having to be laid up for major repairs dropped from 13,627 in 1977 to 6,500 in 1981.

For the electric utility industry, it is possible to halt this declining trend in generating unit performance: obsolete or defective equipment can be replaced. Additional pulverizers can be installed to compensate for poorer quality fuel. Increases in maintenance expenditures could also be expected to improve unit performance. This brings us back to the basic regulatory question: What are appropriate performance standards?

IV. SETTING APPROPRIATE PERFORMANCE STANDARDS

A major result of our analysis is that a performance standard, whether set internally by management or externally by a regulatory commission, should recognize the major differences among generating units. Moreover, if financial factors, such as rate of return do indeed affect generating unit performance, utility managers and commissioners should avoid incentives that could backfire and send a utility into a declining cycle of low availability, poor heat rates, high fuel costs and low returns on investment.

There is one other aspect of the NERA study involving standards. Our analysis showed a large variation in generating unit performance. Some of this variation can be explained by engineering factors and coal quality: our model explained 22 percent of the variation among annual equivalent availabilities of units ($R^2 = .22$). There are analysts who would argue that an R^2 of .22 is not very high. But size alone (the EEI/NERC characteristic for differentiating units) explains only 9 percent of the variation. Using the 10-year average rather than annual equivalent availability in our model increases the R^2 from .22 to .56, because the average smooths out some of the annual variation.

The difference between the R^2s of the annual and 10-year average regressions carries important policy implications. It suggests that whatever performance "standard" regulators choose should be based on some kind of *range*. The size of the range should depend on the length of the period and number of units under consideration. The shorter the test period, the wider the range. Similarly as the number of units included in the average decreases,the wider the range. If a standard is set on a unit-by-unit and year-by-year basis, the range should be quite large. For example, for one specific individual unit in a *single* year, one standard deviation from the average (plus or minus) covers a range in availability from 43 to 78 percent. One standard deviation from the mean for the same unit's *10-year* performance would fall between 64 and 75 percent.

One further caveat: it is wrong to attribute the unexplained variation in models like these to "management". The unexplained variation is due to missing explanatory variables, one of which may be "management". But there are many other reasons: we did not include conversion to oil and reconversion to coal as a variable. Nor did we include Brown Boveri as a turbine manufacturer, because only one unit had such a turbine, and so on. The variables we did include had a significant effect on availability but together did not explain all the variation in unit performance. *Inclusion of additional variables would no doubt explain more of the variation in performance.*

In the meantime, commissioners should not judge generating unit performance below an industry average as proof of management incompetence, nor performance above the average as evidence of merit. However, regulators should acknowledge the demonstrated relationship between a utility's earnings and the performance of that company's generating equipment.

TIME-OF-DAY PRICING IN THE 1980s

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I. INTRODUCTION

Before commenting briefly about pricing in the decade ahead, we might for a moment glance backwards a century to see how far the electric utility industry has come. Just 100 years ago, Thomas Edison's historic Pearl Street power plant began supplying electricity to a handful of customers in New York City. A newspaper journalist reported that:

> The giant dynamos were started up at 3 o'clock in the afternoon, and, according to Mr. Edison, they will go on forever unless stopped by an earthquake.
>
> The New York Times
> September 5, 1882

Edison's optimistic prediction reflected his great entrepreneurial vision of what the electric utility industry would become as well as his enormous self-confidence. His dramatic scientific and commercial achievements at Pearl Street were quickly replicated across the nation. From that modest beginn[illegible] the practical and pervasive adaptation of electric energy, over the years, profoundly transformed our lives. Selling electric energy is now a $100 billi[illegible] year industry. Edison's "giant" dynamos--machines that supply electricity--would be dwarfed by today's 1,000 megawatt generating units.

Also one hundred years ago, Edison's perfection of the incandescent light--a device that used electricity--was heralded as another luminous jewel in the inventor's crown. The New York Times, whose office building was among the first to be connected to Edison's dynamo, noted in 1882 that the "electric light has proved in every way satisfactory." Thus, the light bulb made the system a commercial success because the bulb could convert electric energy into light--which was what customers wanted. Much later, at Christmas-time in 1982, the The New York Times reported at great length that Pac-Man and other video games by the millions had shined forth brilliantly from the electronic vacuum-tube descendents of Edison's carbon filament bulb--much to the delight and satisfaction of children and adults.

A century ago, a simple electric current produced light for a journalist in a lower Manhattan newspaper office. Today, that stream of electrons projects the voice and image of Dan Rather into the homes of 10 million families around the country. There he sits in a midtown New York television studio under blazing high intensity lamps--reading to us the news of today from a motor-driven telepromptor. At times, we might see him hunched over a word processor, a modern day resurrection of the anonymous Times reporter who had marveled at and written about the superiority--compared to flickering gas lamps--of electric light bulbs.

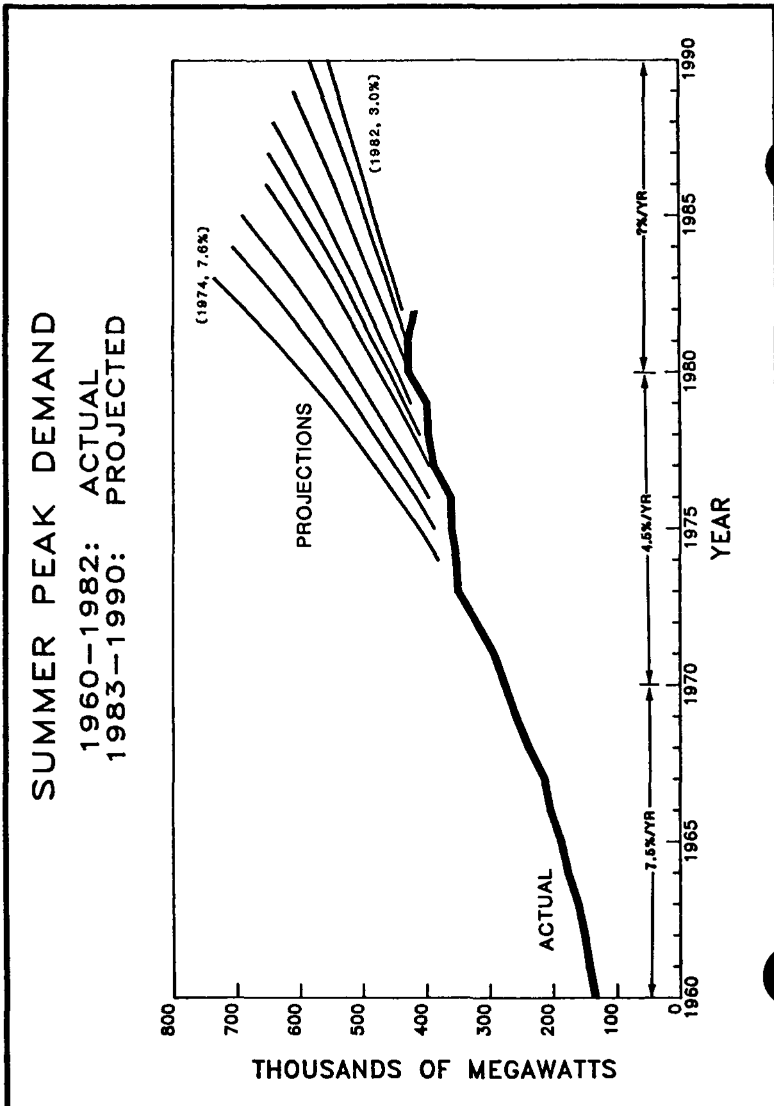
Despite this bright past, the electric utility industry today--and, admittedly, the rest of the economy--seems bogged down. Instead of lowering the cost of electricity, bringing modern new power plants on line gives utility managers heartburn and consumers rate shock. Where once state regulators, utility executives, stockholders and ratepayers peacefully coexisted, guerrilla warfare, if not all-out war, mars the regulatory landscape. Utility securities, once blue chip, are faded and frayed. The triumph of "atomic power" seems hollow, as nuclear power plant cancellations and postponements litter the ground. In 1982, the entire U.S. electric utility industry did not order a single new steam turbine--the first time in 50 years. And, as a final, ignominious blow, peak demand fell last summer--about two percent--also a first time for an industry that had grown rapidly for most of its existence. (Figure 1, the heavy dark line).(1)

II. THE RECENT PAST

Although it is uplifting to look back to the 19th century origins of the electric utility industry, it is sobering if not disquieting to try to look 10 years ahead. Over the past decade, the industry's ability to forecast its own future has been poor at best--so peering ahead just a few years is fraught with uncertainty (Also Figure 1, the "fan" of light lines represents the industry's recent forecasts.)(2) Yet, we can analyze what has happened in the recent past and then be fearless in trying to look ahead.

How is this relevant to an appraisal of time-of-day (TOD) pricing in the 1980s? First, the price of electricity (both level and rate structure) is an important determinant of demand--and, hence, load growth. Second, the price of electricity generally reflects the costs of producing that energy. To some extent, those prices or rates reflect the time-varying and marginal costs of

FIGURE 1


SUMMER PEAK DEMAND
1960–1982: ACTUAL
1983–1990: PROJECTED
PROJECTIONS
ACTUAL
(1974, 7.6%)
(1982, 3.0%)
7.5%/YR
4.5%/YR
?%/YR
YEAR
1960
1965
1970
1975
1980
1985
1990
THOUSANDS OF MEGAWATTS
0
100
200
300
400
500
600
700
800

supplying electric service. Third, as customers' demands grow--shaped by prices that reflect a utility's costs--the company will add new power plants and modify the way it operates its mix of generating capacity. Over time, as load patterns change, the utility's costs will change, rates will be adjusted and demand will be affected some more. This process is now grinding away at many utilities.

Because most electric utilities' costs do vary by time of day, it is often appropriate to reflect such cost patterns in a company's prices--rates would be higher during periods of peak demand because it costs more to produce tricity then. Such time-differentiated rates would tend to slow the growth peak demand and dampen the use of energy during peak hours of the day. This would generally lessen the need to build additional generating capacity, lower a utility's financing requirements, hold down costs and minimize rate shock for consumers. Some utilities, over the past few years, have documented these relationships and effects. Moreover, TOD pricing could help a utility operate its existing generating capacity more intensively and, perhaps, more efficiently--in terms of minimizing total costs to consumers. Thus, given current regulatory practices and attitudes, some utility executives, investors and ratepayers believe that they would be better off in a no growth (or slow growth) mode over the next decade. Time-differentiated pricing fits nicely into this scenario.

TOD pricing is hardly a novel pricing concept. Patents for TOD metering were issued well before the turn of the 19th century, and "load leveling" has been a cherished industry practice since Edison's days. Nevertheless, historically, TOD pricing has not been widespread. According to one study, during the period 1925-1935, only some 15 utilities offered off-peak pricing provisions to nonresidential customers.(3) Also according to that study, over the next 30 years, only six utilities offered off-peak rates. Then, for the years 1966-1976, the study noted that just 13 utilities reported selling electric service under time-differentiated rates. The accuracy of this particular study (done in 1977) is less important than the fact that from 1920 to 1976, very little electricity was sold under TOD rates--even though the pricing concept was well understood, and metering technology and cost were hardly barriers for adopting this practice for large customers. There were, however, other electricity pricing wrinkles, such as special water heating rates and declining block rate structures, that incorporated time-of-use cost considerations yet avoided the necessity of metering the time of use.

A more recent study (done two years later in 1979) revealed that over 100 investor-owned utilities had some kind of TOD rate in effect.(4) Moreover, that study listed 37 state regulatory commissions that had either approved or ordered time-differentiated rates. But, many of those rates were experimental or optional or only available to small subgroups of customers. What might have eared to have been a widespread adoption of TOD pricing--three of four s ago--was really not the case. For example, there were <u>mandatory</u> TOD es for nonresidential customers in only eight states, involving just 19 utilities. Nationwide, barely a few thousand large customers were affected. One might conclude that not much had changed since the 1930s when a dozen or so utilities had used off-peak pricing incentives to build or level electric loads. That, of course, was not the case either.

Under federal prodding (e.g., the Public Utility Regulatory Policies Act of 1978) and, in many states at their own initiative, state regulatory commissions began the long and difficult process of considering and implementing a host of rate reform measures--one of which was "peak load pricing." In 1979, still another survey—one of many PURPA-related polls--reported that about half of the state commissions were considering or getting ready to consider TOD pricing.(5) Yet, even then, several states had already implemented some form of peak load pricing. Another poll, completed in 1980, noted that most regulatory bodies were still mulling over TOD rates.(6) Finally, a 1982 survey confirmed that slowly but surely some 33 state commissions had adopted TOD rates and of those commissions, 24 had implemented TOD pricing.(7) Just two states had rejected the PURPA TOD standard. Two maps of the United States (Figures 2 and 3) show how this particular rate design feature has gradually spread across the nation.(8)

Surveys, however, are blunt analytical instruments. Certainly, the number of TOD rate schedules has proliferated, and the amount of kilowatt-hours sold on a time-of-use basis has increased greatly since 1978. But what lies ahead?

III. THE NEXT DECADE

The role of TOD pricing in the 1980s will depend, in part, on what happens to the nation's economy and the electric utility industry over the next 10 years. As noted above, the demand for electricity (both in kilowatt-hours and kilowatts of peak demand) was down in 1982 compared to 1981--an occurrence of historic significance. Part of that decline can be attributed to this country's deep and prolonged recession--actually a depression in some regions. A portion of the drop in electric usage reflects the reaction of consumers to higher electricity prices, including conservation investments by ratepayers. Only a very small part of the decline--in peak demand--might be attributed to TOD pricing, and part to moderate summer weather.

Today, the electric utility industry is probably overbuilt in terms of its own generating capacity. Reserve margins are more than adequate in most parts of the country--making regulators anxious and utility managers nervous. Although many planned power plants--both nuclear and coal--have been cancelled or delayed, there is a large amount of additional new capacity about ready to pop out of the construction pipeline. In brief, the industry seems to have more than enough capacity to meet loads--at least in the near term.

There is, however, some concern about electric power supply adequacy and reliability at the end of the decade, at least for some regions. If the economy recovers (and most Americans are fervently praying for this), electric utility load growth could resume--not at the 7 percent per year growth rate of the 1960s, but perhaps at the 3 percent of the late 1970s (2 percent annually is currently a fashionable number among deep thinkers). If electric load growth returns--and it will--utility managers may elect, however, to avoid construction of new generating capacity. Slogans such as "no new power plant construction for the rest of the century" have cropped up in utility executives' statements and

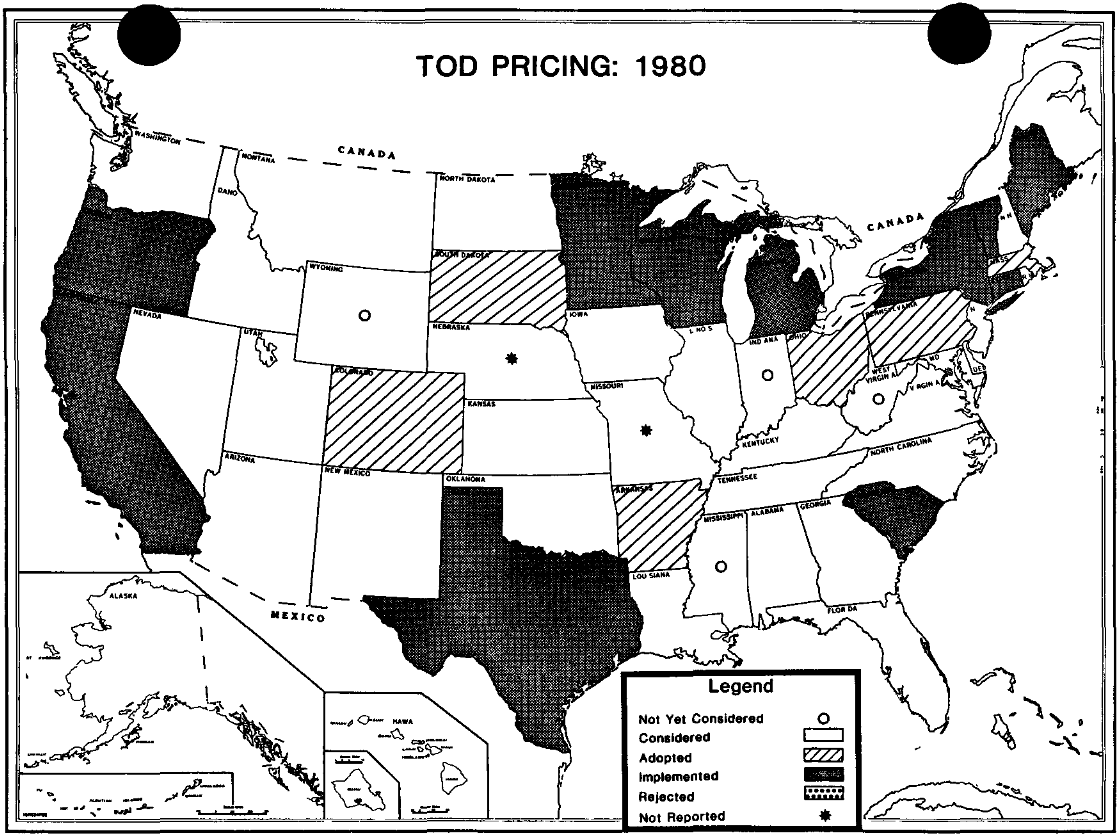

TOD PRICING: 1980
CANADA
MEXICO
WASHINGTON
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
WYOMING
NEVADA
UTAH
NEBRASKA
COLORADO
KANSAS
ARIZONA
NEW MEXICO
OKLAHOMA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
TENNESSEE
KENTUCKY
NORTH CAROLINA
PENNSYLVANIA
WEST VIRGINIA
VIRGINIA
MD
DEL
ALASKA
Legend
Not Yet Considered
Considered
Adopted
Implemented
Rejected
Not Reported

FIGURE 2

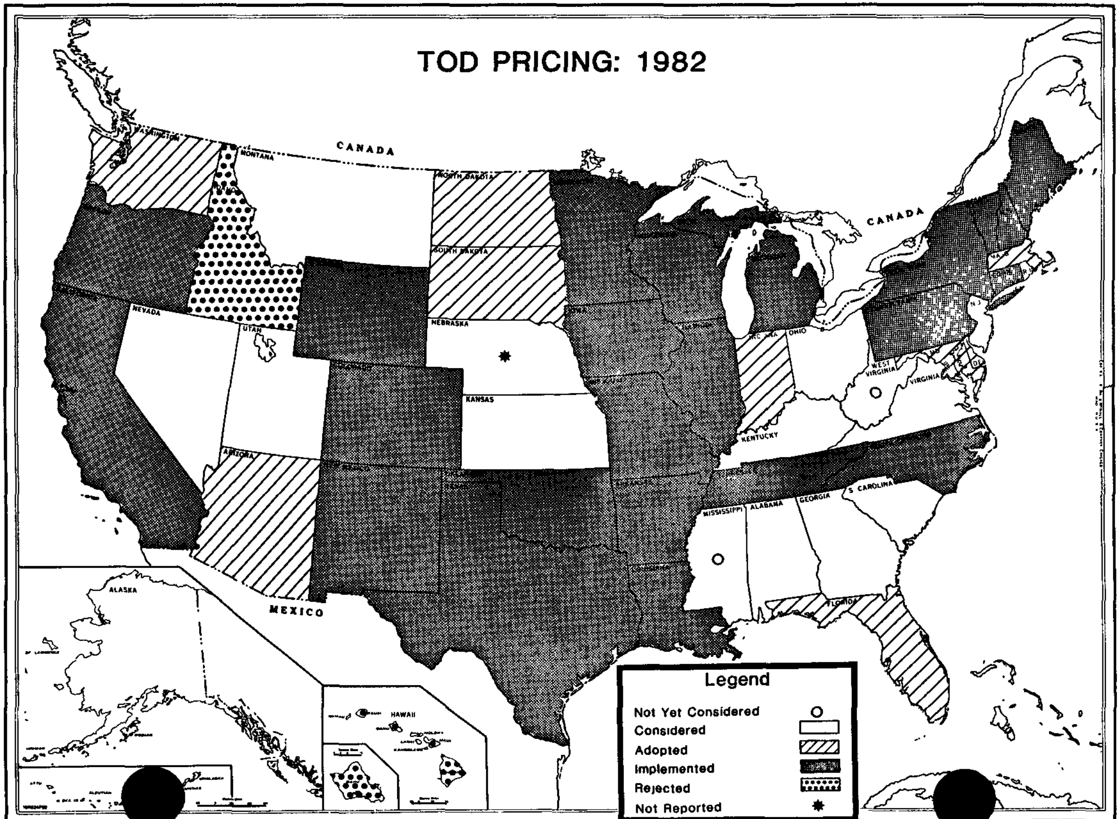

TOD PRICING: 1982
CANADA
MEXICO
WASHINGTON
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
NEVADA
UTAH
ARIZONA
OHIO
WEST VIRGINIA
VIRGINIA
KENTUCKY
S CAROLINA
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
ALASKA
HAWAII
Legend
Not Yet Considered
Considered
Adopted
Implemented
Rejected
Not Reported

FIGURE 3

testimony. It is quite conceivable that today's descendents of Thomas Edison--some are visionary entrepreneurs--may choose to take their money and run--turning the electric companies into aging cash cows, at least in the 1980s.

TOD pricing in particular and load management in general are handy tools for carrying out such a scheme. Controlling the demand side of their business could give utility executives some long sought after financial breathing space. Why should they add new power plants on the supply side (to the detriment of shareholders), if consumers' demands can be juggled or constrained by cost-based time-varying rates and other measures? Moreover, if ratepayers rebel because of rate shock, why provoke them and incur the certain wrath of regulators by building costly new plants?

If you believe the engineers, and have faith in research and development, the cost of metering will fall. If, in addition, you trust economists, and accept their theories and models, the costs of producing electricity will rise. Finally, if you believe consumer activists, the utilities will continue to be challenged and put under the gun to hold down rates, unbundle their services (e.g., sell off-peak electricity at a lower price) and increase customers' options (e.g., sell interruptible or controlled electric service at a lower price). Thus, it seems likely that the underlying technical, economic and political forces are in place to push TOD pricing into more markets in the 1980s.

California offers a striking example. Over the past five years, the TOD rate net's mesh has been made progressively finer by the electric utilities, snaring smaller and smaller industrial customers. At the same time, the utilities' attempts to place large residential customers on TOD rates have intensified. This, of course, has occurred at the prodding of the activist California Public Utilities Commission but also because the utilities have been frustrated in their attempts to maintain adequate generating reserve margins. Nevertheless, load management, conservation and TOD pricing are growing, if not flourishing, in Lotus Land.

Also from the Golden West comes another wave of the future--the semiconductor and its high technology progeny--including a reasonably priced electronic meter (a "smart" meter measures usage by time of day as well as controls multiple loads). More generally, and as everyone knows, computers and new forms of communications are changing the way we live, work and play. Thus, it takes little imagination to see that with a smart TOD meter, computers and enhanced communications, particularly with the split-up of AT&T, a more careful balancing of electricity demand (of millions of consumers) and supply (by hundreds of large and small interconnected power producers) could become technically feasible in the 1980s. Moreover, given the current thrust toward deregulation and a greater reliance on competitive markets, a wider and more rapid adoption of time-of-use rates and other innovative pricing and service options seems likely as electric utilities refocus their marketing efforts.

IV. CONCLUSION

This is all hardly surprising. For years, electric utilities have been exchanging energy at time-differentiated marginal cost-based prices in integrated power pools and less formally among neighboring utilities as a way of evening up supply and demand. More recently, in Florida, a brokerage system among power generators has been set up. It permits member utilities to buy and sell energy at wholesale prices that fluctuate hourly. In California, innovative experiment is about to be launched that will tightly link one utili PG&E--with several of its large industrial customers. That linkage will pe electric energy retail sales to take place at prices that vary as the utility's actual costs change--from hour to hour or by 15-minute intervals.

In summary, the question is not whether TOD pricing will be adopted in the 1980s. The questions are: In what forms, for which consumers and how quickly will TOD rates be implemented? Moreover, the truly entrepreneurial utility executive will try to answer a more difficult question: How can I structure my electric rates--not to increase sales of kilowatt-hours next year--but to maximize realized return on investment over the long haul? Finally, the really shrewd business manager or clever householder must try to solve an even tougher question: What will electric rates be--both level and structure--and what should I do to take advantage of them? One hundred years ago, a shrewd and clever inventor answered much more difficult questions and created a great industry that benefits all of us today. In comparison, figuring out how to use TOD pricing in the 1980s should be easy.

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(1) For peak demand data see Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1970, Table 6, p. 20 for 1960-1970; Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, Table 6, p. 12 for 1971-1972; National Electric Reliability Council, Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, Annual Volumes for 1973-1979; North American Electric Reliability Council, Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, Annual Volumes for 1980-1981.

(2) National Electric Reliability Council, Annual Reviews, 1973-1979; North American Electric Reliability Council, Annual Reviews, 1980-1981.

(3) Task Force No. 1, Analysis of Various Pricing Approaches: Topic 1, prepared for the Electric Utility Rate Design Study (Palo Alto, Califor Electric Power Research Institute, February 2, 1977).

(4) Zinder Companies, Inc., A Survey of Time-of-Day Rates of Investor-Owned Electric Utilities, prepared in cooperation with the Edison Electric Institute's Utility Regulatory Analysis Program (URAP), December 1979, p. 3.

(5) Electric Utility Rate Design Study, 1979 Survey: State and Federal Regulatory Commissions, Electric Utility Rate Design and Load Management Activities, June 7, 1979, Table D, pp.12-13.

(6) "NARUC Survey: States' Status on PURPA Compliance" reported in Electrical Week, December 1, 1980, p. 1.

(7) "NARUC Survey: States' Status on PURPA Compliance as of May 30," reported in Electrical Week, November 8, 1982, p. 10.

(8) See footnotes (5), (6) and (7) for the sources of the data used to prepare the maps. If a state's status was not reported in the 1980 survey, the 1979 survey was used. If a state's status was not reported in the 1982 survey, the 1980 survey was used if possible; if not, the 1979 survey was used.

PREDICTING CUSTOMER RESPONSE TO TIME-OF-USE ELECTRICITY RATES: INSIGHTS FROM EPRI RESEARCH

Ahmad Faruqui*
Douglas W. Caves†
Laurits R. Christensen†
Joseph A. Herriges†
Kay K. Lee‡
Allen K. Miedema‡

Knowledge of customer response to time-of-use (TOU) electricity rates is an important element in analyzing the costs and benefits of innovative rate programs. Sources of such knowledge include historical analysis, social experimentation, economic transfer, and engineering simulation.

The American experience with TOU rates has been confined mostly to large power customers. Even for these customers, the recorded data contain insufficient variation to permit reliable measurement of customer response through statistical means. Social experiments have been conducted for residential customers in some utility service areas, but these tend to be expensive and time consuming.

In this paper, we provide insights from two major ongoing projects on TOU pricing sponsored by the Electric Power Research Institute (EPRI). One of these projects deals with residential response and is being conducted by

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‡Research Triangle Institute, North Carolina

Christensen Associates (EPRI RP1956). The project uses econometric transfer methods, i.e., data from a limited number of social experiments in specific service areas are used to develop a model that can be applied in other service areas. Econometric transfer across geographic regions can combine the accuracy of experimentation with the low cost of historical analysis. The other project deals with industrial and commercial customers and is being conducted by Research Triangle Institute (RTI), with Chem Systems as a subcontractor (EPRI RP2043). In this project, engineering simulation models are used to analyze industrial response.

The residential project is discussed in Part A, followed by a discussion of the industrial project in Part B.

PART A. RESIDENTIAL RESPONSE [1]

Several factors may be important in determining the response that results when a specific TOU rate is implemented. One of the critical factors is the composition of the rate structure itself--the number of and timing of pricing periods and the rates charged during each period. Other potentially important factors, which we refer to as conditioning factors, include the general rate level, climate, and demographic, economic, and appliance ownership characteristics of the customer population. The key to transferability is to determine the relationship between customer reponse and these factors. If a model of this relationship can be developed on the basis of data from regions that have conducted controlled social experiments with TOU pricing, then utilities in other regions could use the models to predict customer reaponse. Once the model is developed it would be inexpensive to use. Thus econometric transfer of load shape changes may be a cost-effective alternative to experimentation.

DATA BASE CONSIDERATIONS

The transferability studies reviewed in this paper draw upon data generated in the U.S. Department of Energy (DOE) Rate Demonstration Program, 1975-81. The DOE program featured fourteen residential TOU pricing projects, nine of which yielded data that are of use in developing a transferability model (see Figure 1).

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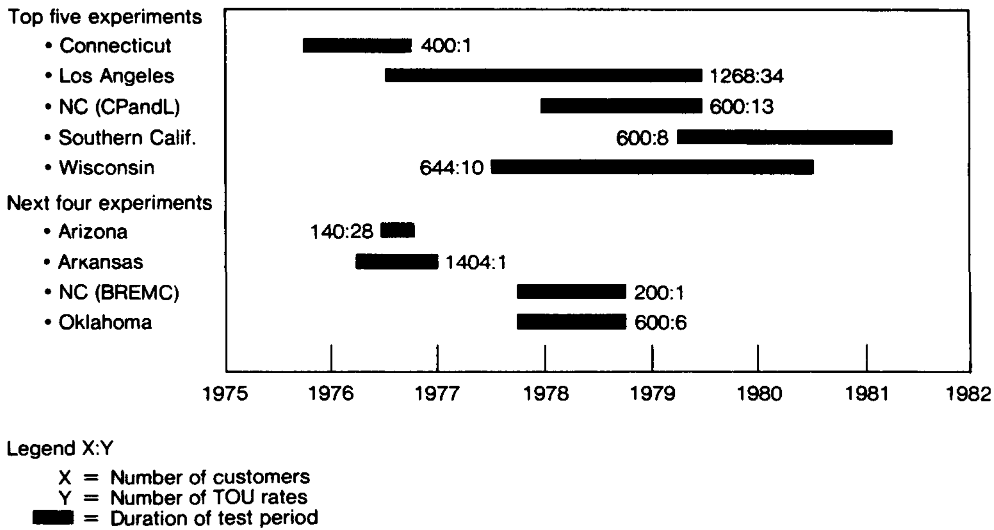
[1] This section draws from material in D. W. Caves et al., "Transferability of Residential Response to Time-of-Use Electricity Rates," presented at the Fourteenth Annual Conference, Institute of Public Utilities, Williamsburg, Virginia, December 14, 1982.

Figure 1

THE DOE EXPERIMENTS



In Table I, we compare the climatological and rate level characteristics of the DOE projects with the rest of the nation. The comparison indicates that the DOE projects are broadly representative of the rest of the nation in these respects. Thus a transferability model based on the DOE projects should be of considerable value in most regions of the country.

In Figures 1 and 2, we provide some information on the experimental design of the top nine DOE projects. There was considerable variation in the designs of the experiments. The better projects ran for more than a year and involved several TOU rates. In addition, the better designed projects obtained two types of control information. First, all customers were observed on standard rates during a baseline period. Second, during the test period customers were randomly assigned either to go on an experimental TOU rate or to remain on the standard rate.

METHODOLOGY

Response estimates can be transferred in several ways. The EPRI/Christensen Associates project draws upon data from several experiments to assess the transferability of customer response estimates. A measure of customer response is developed which, in the simplest formulation, relates changes in the ratio of peak to off-peak usage to changes in the ratio of the peak-to-off-peak price. For example, in the case of two pricing periods, the following relationship is estimated:

$$\mathrm{Ln}\,(kWh_p/kWh_o) = A - B\,\mathrm{Ln}(P_p/P_o)$$

where kWh_p = usage on peak, kWh_o = usage off-peak, P_p = price of peak usage, and P_o = price of off-peak usage. Customer response is given by B. In more complex models, the A and B parameters are specified as functions of customer characteristics, such as appliance ownership, sociodemographic profile and economic status, as well as service area characteristics, such as climate.

The analysis of load curve changes proceeds in three stages. In the first stage, energy substitution between the pricing periods is estimated on an average weekday, holding fixed the level of aggregate weekday use. In the second stage, substitution between aggregate weekday use and aggregate weekend use is analyzed, holding fixed the level of aggregate monthly use. In the third stage, substitution between aggregate monthly use and all other commodities besides electricity is analyzed. Separate analyses are conducted for the summer and winter seasons. The effects of the three stages in obtaining the total effect of TOU prices is illustrated in Figure 3.

Table I

COMPARISON OF DOE EXPERIMENTS WITH REST OF THE NATION

Variable	*Season/Other*	*Experiments*	*Nation*
Climate (degree days)	Summer	352 (189)	290 (155)
	Winter	849 (380)	1022 (372)
Rate level (¢/kWh)	Summer		
	400 kWh	3 30 (0 90)	3 25 (1 15)
	1000 kWh	3 13 (0 89)	3 09 (1 37)
	Winter		
	400 kWh	3 49 (0 39)	3 18 (1 23)
	1000 kWh	2 61 (0 93)	2 75 (1 30)

X = Mean
(Y) = (standard deviation)

Figure 2

DESIGN OF A TYPICAL EXPERIMENT
Wisconsin

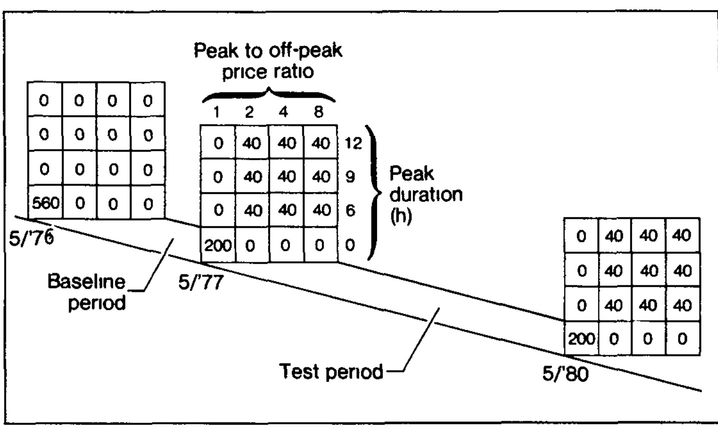
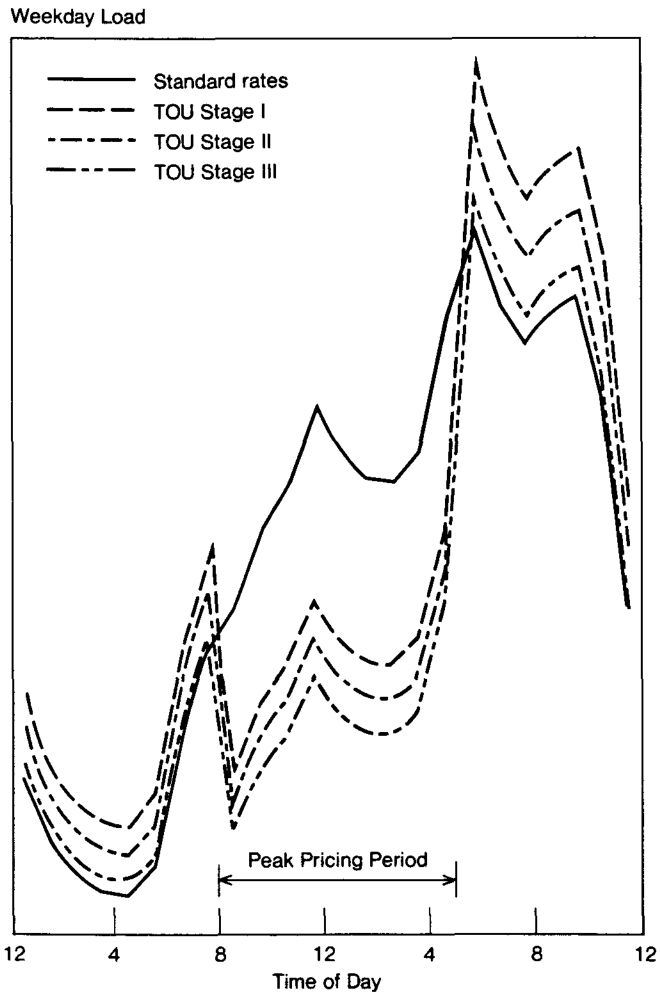


Figure 3

EPRI/CHRISTENSEN ASSOCIATES METHODOLOGY FOR PREDICTING RESIDENTIAL LOAD CURVE UNDER TOU PRICING



RESULTS

Table II reports estimates of B that result from applying a version of the model to assessing peak to off-peak substitution on average summer weekdays (Stage I). The middle column marked "average household" presents a picture of remarkable similarity across the five projects. The other two columns present contrasting results for a household with no major electric appliances and one with all major electrical appliances (air conditioner, water heater, clothes dryer, range and dishwasher). In all cases, appliance ownership adds significantly to customer response.

The implications of differences in customer response estimates attributable to appliance portfolio differences are traced out in Figure 4. The share of total energy used during the peak period on an average weekday can be expected to decline by nine percentage points for a household with all major electrical appliances as it goes from a flat rate to an 8:1 TOU rate. For a household with none of the major electrical appliances, the share will decline by only half a percentage point. For the average household the share will decline by seven percentage points.

A comparison of customer response estimates for weekdays with estimates for peak days reveals little difference in the response pattern. Thus the experimental data do not justify the skepticism that has been voiced about TOU rates by some analysts regarding their lack of effectiveness on days of system peak.

Results from Stage II of the model show statistically significant substitution in this stage, but of a smaller magnitude than Stage I. There is also more variation across the projects than in Stage I. It is not yet known whether this variation can be explained by conditioning variables.

At Stage III the model permits a response due to the aggregate price change inherent in the TOU rate, as well as a conservation effect. The conservation effect includes the effect of the TOU rate that is unrelated to the magnitude of the price change associated with the rate. Because the experiments were designed to be revenue neutral (with no change in usage the average customer would have the same bill on TOU rates as on standard rates) there was very little variation in the overall price of electricity. Thus the price effect at Stage III, using data from four experiments, could not be precisely estimated. The estimates of the conservation effect also showed low statistical significance, but were consistent in sign. On average the conservation effect suggests about a ten percent reduction in total usage aasociated with TOU rates.

Table II

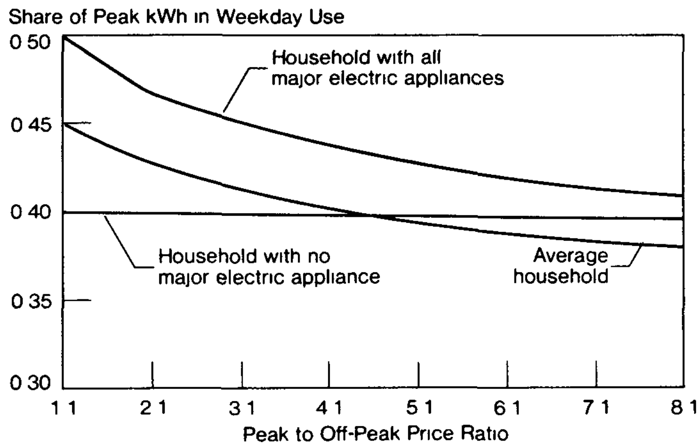
RESIDENTIAL CUSTOMER RESPONSE TO TOU RATES
Stage I Summer Estimates

	Household Without Appliances		Average Household		Household With Appliances	
	Estimate	Standard Error	Estimate	Standard Error	Estimate	Standard Error
California (SCE) A	-.01	(.06)	.14	(.03)	.21	(.06)
California (SCE) B	.06	(.06)	.16	(.03)	.22	(.05)
Connecticut	.05	(.06)	.12	(.02)	.19	(.04)
North Carolina	-.18	(.19)	.16	(.06)	.11	(.10)
Wisconsin 6	.10	(.05)	.13	(.02)	.14	(.05)
Wisconsin 9	.10	(.05)	.13	(.02)	.13	(.06)
Wisconsin 12	-.03	(.05)	.14	(.02)	.29	(.06)
Average of Above	.01	(.07)	.14	(.01)	.18	(.06)
Los Angeles Average	.09	(.06)	.14	(.04)	.33	(.21)

Source: Christensen Associates, EPRI RP1956 Report, forthcoming 1983.

Figure 4

EFFECT OF MAJOR ELECTRICAL APPLIANCES ON CUSTOMER RESPONSE
Summer Estimates



The EPRI/Christensen Associates study will be completed in the spring of 1983. Currently, statistical tests are being conducted to determine the extent to which a single statistical model can describe the data from the various experiments. In addition to the results presented here, the project is investigating several additional areas, including (1) effect of climate on customer response, (2) use of interregional variation in rate levels to develop aggregate price elasticities, and (3) disaggregation of peak and off-peak periods into subperiods to permit more detailed response estimates by time-of-use.

PART B. INDUSTRIAL RESPONSE [2]

A case study approach has been taken in the EPRI/RTI study of industrial and commercial response, given the substantial diversity in electric usage patterns that characterize large power loads. Early results from the industrial phase of the project are available at this time and will be reported in this part of the paper.

Two industries, chlor-alkali (SIC 2812) and cement (SIC 3241), were selected for detailed analysis based on three main criteria: electric intensity (share of electricity costs in value of shipments), regional dispersion of plants, and share of total manufacturing electricity use. Table III presents a summary of these two industries based on these criteria.

METHODOLOGY

For each of the two industries, a simple process model of electricity use was developed for a typical plant, using data from engineering studies, on-site plant visits, and industry trade associations. The models are designed to identify explicitly the coping mechanisms that plants may use as they respond to alternative TOU rates. The operating principle is that plants seek to minimize the costs of producing a given output level. The predicted load shape modifications are then to be validated through comparison with utility load data on customers in these industries who have been on TOU rates.

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[2] This section draws from material in A. K. Miedema and K. K. Lee, "Responses of Industrial and Commercial Customers to Time-of-Use Rates," presented at the EPRI Seminar on Planning and Assessment of Load Management, San Antonio, Texas, December 8, 1982.

Table III

SUMMARY DATA ON THE CHLOR-ALKALI AND CEMENT INDUSTRIES

Characteristics	Chlor-Alkali	Cement	All Manufacturing
I. General Business Data			
A. Value of shipments (10^6\$)	1,354	3,963	1,850,927
B. Total employment (10^3)	7.4	30.4	20,644.9
C. Share of labor cost in value of shipments (%)	13	17.6	18.9
D. Capacity (10^6 tons)	14.5 (chlorine)	91 (portland cement)	n/a
II. Other Business Data			
A. Market share of top four firms (%)	68	30	n/a
B. Number of establishments	26	45	350,757 (1977)
C. Number of plants	57	143	n/a
D. Regional dispersion (States with one or more plant)	24	40	n/a
III. Energy Data			
A. Total electricity use (10^6 kWh)	10,680	9,238	658,104
B. Share of electricity cost in total energy cost (%)	66.7	34.1	45.2
C. Share of electricity cost in value of shipments (%)	19.6	8.2	1.2
D. Share of energy cost in value of shipments (%)	29.4	24.1	2.6

Notes: *n/a = not applicable*

Sources: 1980 Annual Survey of Manufacturers; RTI Reports on EPRI RP2

CHLOR-ALKALI INDUSTRY

Figure 5 presents a simple description of the process flows in this industry. Electricity use is concentrated in the electrolysis stage. About three-fourths of the existing cells are of the diaphragm variety, and their usage can be modulated from 80 to 130% of nominal capacity. Mercury cells account for the remainder of existing capacity; this technology is not likely to play a major role in the next five to 10 years, because of environmental discharge problems. A new technology which looks quite promising for the future is membrane cells. Electricity use in these cells can be modulated from 50-130%. Because of efficiency considerations, the normal mode of operation of all cells is continuous. In periods of slack capacity, some cells are completely shut down while others run at full capacity.

A process model was constructed for a typical plant based on diaphragm cells with a capacity of 1000 tons per day. Two types of coping mechanisms were identified as technically feasible: (1) load modulation, which involves reducing peak electric usage and expanding capacity to permit increased off-peak usage; and (2) cell replacement, which involves replacing some diaphragm cells with more time-flexible membrane cells.

Where faced with a range of TOU rates of increasing peak to off-peak intensity, the model selected the following economically efficient coping mechanisms:

(1) initially, peak usage is reduced to 80% and plant capacity is expanded by 6%.

(2) next, portions of existing capacity are replaced by membrane cells. Existing capacity is operated at 80% peak, 100% off-peak; new capacity at 61% peak, 122% off-peak.

(3) finally, all existing capacity is replaced by membrane cells and operated at 61% peak, 122% off-peak.

The effect of these changes on the share of peak usage to daily usage is shown in Figure 6. The sensitivity of model predictions to some of the model assumptions is also illustrated in the figure with reference to the fixed charge rate. The results of the model simulation are consistent with a priori expectations that the coping mechanisms will become more capital-intensive as the peak to off-peak ratio increases. And each mechanism will be less capital-intensive at higher fixed capital charge rates.

Figure 5

CHLOR-ALKALI PRODUCTION

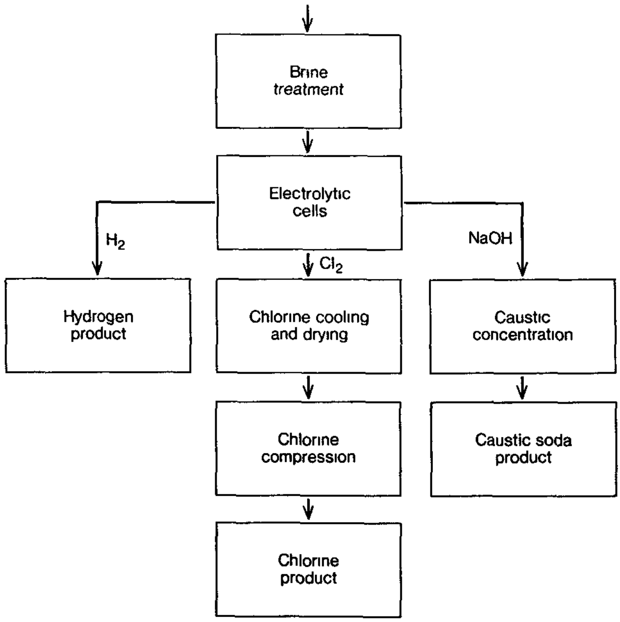
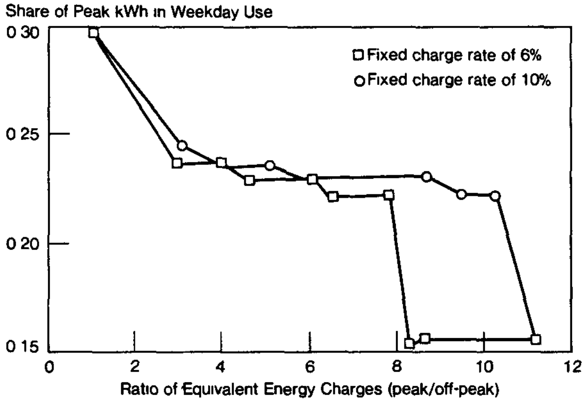


Figure 6

SIMULATED RESPONSE OF CHLORINE PLANT



Note Off-peak energy charge = 2¢/kWh off-peak demand charge = $2/kW
Equivalent energy charge = total demand charges plus energy charges ÷ total kWh
Equivalent energy charge off-peak = 2 4¢/kWh

CEMENT INDUSTRY

The process flows in cement production are illustrated in Figure 7. About two-thirds of electricity use is concentrated in the raw and finish grinding stages. Two alternative technologies are used in the grinding stage--the dry process and the wet process. Energy consumption is lower in the wet process because the raw materials are softened with about 30-40% water.

The process model can represent either the wet or the dry process. The typical plant is specified to have a capacity of 2200 tons per day, and May-October is defined as the peak season. The following coping mechanisms are identified as being technically feasible:

- Reduce grinding operations during peak hours in summer months--may require grinding capacity expansion (no seasonal shift).
- Shift some grinding operations from peak hours in summer months to off-peak hours in winter months--may require expansion of grinding and storage capacities (partial seasonal shift).
- Shift some grinding operations from peak hours in summer months to peak and off-peak hours in winter months--may require storage capacity expansion (full seasonal shift).
- Reschedule crushing operation.

When faced with alternative sets of TOU rates that progressively increase the peak to off-peak price ratio, the model chooses the following coping mechanisms:

- Operate raw and finish grinding mills for 65% of peak hours in summer months and make up the difference during off-peak hours in winter months.
- Shut down finish grinding mill during peak hours in summer months and make up the difference during off-peak hours in summer months. Expand finish grinding capacity by 40%.
- Shut down raw and finish grinding mills during peak hours in summer months and make up the difference during off-peak hours in summer months. Expand raw and finish grinding capacity by 40%.

The impact of these changes on the share of peak usage in daily usage is displayed in Figure 8. The difference between summer and winter responses is apparent.

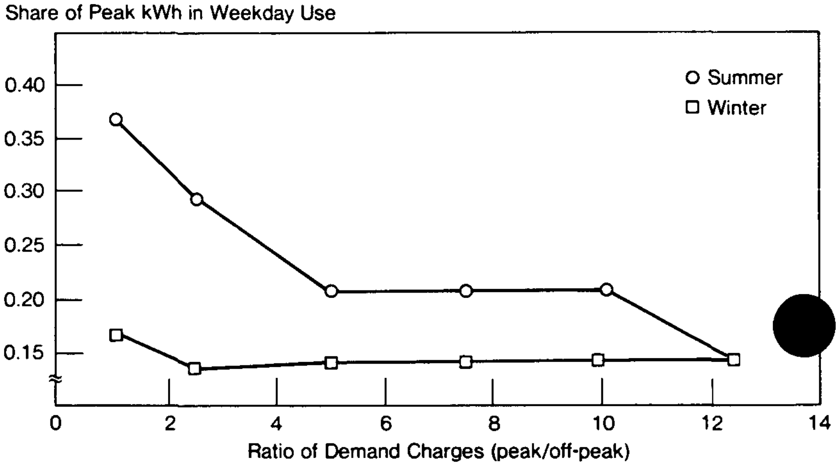
Figure 7

PROCESS DESCRIPTION OF CEMENT PRODUCTION

Normal Operation		*Share of Electricity Use*
Eight hours, weekdays	Crushing	3
Continuous in peak season	Raw grinding	23
Continuous	Kiln	25
Continuous in peak season	Finish grinding	41
Eight hours, weekdays	Packaging	8

Figure 8

SIMULATED RESPONSE OF CEMENT PLANT



Note Energy charges = 5¢/kWh peak and 2¢/kWh off-peak
Off-peak demand charges = $2/kW
Fixed capital charges = 10%

Currently, the predictions generated from model simulation are being validated against the actual load data. Additionally, technology options for the commercial sector are being analyzed with special emphasis on thermal energy storage.

CONCLUSIONS

Results for the residential sector indicate that there is considerable regional similarity in response estimates, and that it may be possible to explain the residual variation in the estimates in terms of conditioning factors. If so, transferability will be a cost-effective alternative to primary experimentation for many utilities. Results for the industrial sector indicate that process models are a viable method for assessing both short-term and long-term responses. These models, if validated successfully against actual load observations, have the potential for providing substantial insights into industrial behavior.

THE AUTOMATION OF INDUSTRIAL AND COMMERCIAL AUDITS

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BACKGROUND

While engineers and managers have always been responsible for identifying cost-effective means for reducing energy use and cost, the relative importance and formalization of the process really were instigated after 1974 as a result of the Arab oil embargo and the subsequent meteoric increases in energy prices. Finding ways to control energy consumption quickly moved to high priority status, particularly in commercial and industrial firms whose profitability (and, in many cases, survivability) were severely threatened by uncontrolled energy cost escalation.

In parallel with the private sector efforts, federal and state governments instituted new laws and programs to encourage energy efficiency in almost every sector of American society. In the late '70's, the prevailing view was that strong government incentives were necessary to accelerate the conservation process. Such measures as the State Energy Conservation Programs (Lighting Standar Energy Building Code, Carpool/Vanpool Program, and therization Program) and Tax Credits for Conservation certain solar applications were typical of these government initiatives and did, indeed, foster much conservation activity.

As a consequence of the increased demand for professional support of conservation activities, various companies as well as individual engineers entered the field and became energy auditors or energy managers. In fact, 1978 saw the founding of a new professional society, the Association of Energy Engineers (AEE), which now has over 3,000 members. The professionals in the field were instrumental in defining and formalizing the energy audit process and in providing their services to many of the larger commercial and industrial firms in the United States. Supported by the increased volume and various other incentives, such as government contracts, the professionals developed various computer programs to assist them in their analysis and lower costs. The elements of a typical energy audit are shown in Figure 1.

Concurrent with the development of the energy audit itself, electric and gas utilities began to change their emphasis from actively marketing increased consumption to the promotion of the 'wise' use of the resource including the reduced use by their customers. For many utilities, the <u>marginal</u> cost exceeds their <u>average</u> revenue, and more efficient use of their capacity is more cost effective than new plant construction. Thus utilities began to encourage or actually to perform energy audits for their customers, both commercial and residential. Title VII National Energy Conservation Policy Act (NECPA) mandated that states develop a plan to provide low-cost audits for residential customers; the law further required that the utilities or their designated agents provide the audits.

Recently, final rules were promulgated by the Federal Government which would effectively extend the requirement for the utilities to provide audits to include smaller commercial and industrial facilities as well as multi-family buildings. Thus, both as a requirement by law and in their own interest, utilities began to actively provide energy audits.

In order to meet the demand for high volume energy audits, and recognizing that the cost of doing any but the simplest walk-through by traditional means would become prohibitive, we instituted in late 1980's the development of a fully automated audit system. The goal of the development was to duplicate, as closely as possible, the professional audit, but with a ten-fold reduction in cost and professional time. Further, the audit would have to deal with the major energy consumers in industrial and commercial buildings, not just 'shell' measures, as is characteristic of the residential programs.

The initial development of the automated audit was accelerated and focused by a concurrent requirement by Northeast Utilities to perform thousands of audits for their commercial and industrial customers in Connecticut

ELEMENTS OF A TYPICAL ENERGY AUDIT

1. A description of the facility being audited and its current energy consumption. Usually current consumption is normalized and broken down by end use. Other key assumptions used in the subsequent analysis typically are presented. These may include utility costs (rates) and inflation figures.

2. A set of specific recommendations for change. These usually include:

   - a description of the recommended measure
   - savings and costs associated with its implementation
   - a recommended method for implementing the measure which could include sketches, contractor quotes, and/or detailed maintenance instructions
   - financial analysis of the recommendation (if sufficient capital is involved), and
   - technical backup material.

   The recommendations are often grouped into operations and maintenance measures (O&M) for which little or no costs are involved and measures which require investment. The treatment of these two classes may differ in the typical energy audit.

3. Items investigated but not recommended. Often measures may save some energy, but are not justified for such reasons as an excessive payback period, undesirable changes to operations, or unacceptable comfort levels. These are documented for the record in a typical energy audit.

Figure 1.

and Massachusetts. Their foresight, that only a comprehensive automated audit would coincide with their twin goals of professional quality and low per audit cost, led them to engage XENERGY Inc. to develop the system. XENCAP^{tm} is the result of that development, and the subject of this paper.

THE XENCAP^{tm} AUDIT SYSTEM

XENCAP^{tm} is a system of computer programs--about [illegible]0,000 lines of code--a data collection system including input forms, a report generation package including insertable text paragraphs, a building and end use database, and a management reporting system to control and monitor the process. The end result of this is to allow an energy auditor to prepare a complete energy audit report, typically 50 pages, in less than four hours. The system currently includes 72 separate measures and over 500 error checks to ensure a comprehensive, reliable result. A listing of the measures is shown in Figure 2.

The XENCAP^{tm} computer program achieves accuracy by simulating the steps of a fully engineered audit:

1. Actual fuel use is allocated among the available end uses.

2. A statistical database of building end-use norms is used as a check to flag errors in allocation and also to adjust energy profiles where data is incomplete or missing.

3. The computer program permits the building to be zoned to reflect varying operating patterns. Further measures are analyzed on a zone-by-zone basis.

4. Accepted engineering calculation methodology is used to evaluate each measure. Incremental fuel costs are used to evaluate savings; for electricity the effects of both usage (KWH) and demand (KW) are considered.

5. The interaction among related measures is appropriately treated in the calculation methodology. It is assumed that low-cost measures are implemented before higher cost measures; the energy baseline is readjusted before computing savings for higher cost measures.

6. The cost to implement measures is computed using accepted costing standards and is regionally based.

MEASURES FOR COMMERCIAL/INDUSTRIAL AUDIT
(Including Multifamily, as applicable)

LIGHTING - INTERIOR AND EXTERIOR

(a) Reduce Operating Hours by:
- manual means
- installation of switches
- installation of time control devices (3 types)

(b) Reduce Light Levels by:
- disconnecting fixtures
- removing 2 lamps from multi-lamp fixtures
- installing no-light lamps
- installing "thriftmate" type lamps or devices
- using lower wattage lamps
- using ER-type lamps
- replacing light output with standard lamps
- redesigning lighting system

(c) Refixturing with High Efficiency Lamps, including
- incandescent to fluorescent conversion
- incandescent to HPS or Metal Halide
- fluorescent or mercury vapor to HPS
- installation of LPS.

(d) Replacement of Standard Fluorescents with Low-Energy Equivalents.

BUILDING SHELL

(a) Modify Windows and Doors, including:
- add storm window/door
- weatherstrip window/door
- add custom glazing
- reduce or modify window areas
- add plastic storms
- add reflective film to windows

(b) Wall Insulation, including:
- add cavity wall insulation
- install interior insulation

(c) Ceiling Insulation, including:
- add insulation in available space
- install interior insulation
- add hung ceiling
- add exterior insulation when re-roofing

Figure 2.

COOLING
(a) Improve Maintenance of Equipment, including:
- cleaning of coils and filters
- repair/replace belts
- refrigerant levels

(b) Install Economizer/Enthalpy Control of Introduction of Outside Air
(c) Consider High EER Equipment

TEMPERATURE CONTROL
(a) Reduce Winter Temperature/Increase Summer Temperature by:
- manual means
- locking thermostats
- thermostatic control valves
- rezoning

(b) Modify Setback/Setforward Schedule by:
- manual means
- timeclocks
- energy management systems
- control modifications

HEATING
(a) Service Heating System
(b) Reduce Burner Nozzle Size
(c) Install Flue Damper
(d) Install Turbulators
(e) Extinguish Pilot Lights in Summer
(f) Install Hot Water Reset System
(g) Replace Burner
(h) Replace Boiler or Furnace

DISTRIBUTION
(a) Add Pipe Insulation to:
- domestic hot water pipes
- heating water pipes
- steam pipes
- condensate pipes

(b) Add Tank Insulation to:
- domestic hot water tanks
- condensate tanks

(c) Add Duct Insulation to:
- hot ducts
- cold ducts

(d) Repair Steam, Hot Water or Duct Leaks
(e) Repair or Replace Faulty Steam Traps
(f) Install Destratification Fans

Figure 2 (Continued).

VENTILATION
(a) Reduce Outside Air by:
- *adjustment or repair of dampers*
- install new dampers (low leakage type)
- system redesign
- use of energy management system for duty cycling

(b) Reduce Fan Operating Time (Night Shutoff) by:
- manual means
- installation of time control
- use of energy management system

HOT WATER
(a) Reduce Delivered Water Temperature
(b) Reduce Requirements by Use of Low-flow Showerheads and Sink Aerators
(c) Shut Off or Cycle Circulator Pumps
(d) Install New Stand-alone Unit

REFRIGERATION
(a) Maintain/Repair Refrigerated Cases
(b) Add Demand Defrost Control
(c) Add Case Covers or Doors
(d) Improve Compressor Efficiency
(e) Reclaim Compressor Waste Heat for Space Heating/Domestic Hot Water

COOKING
(a) Improve Maintenance
(b) Improve Utilization
(c) Recover Heat from Exhaust

TRANSPORTATION
(a) Add Radial Tires
(b) Install Fan Clutch
(c) Install Wind Deflectors
(d) Improve Maintenance
(e) Driver Efficiency

PROCESS ENERGY
(a) Compressed Air System Maintenance
(b) Energy Efficient Motors
(c) Power Factor Control

ALTERNATE ENERGY SOURCES
(a) Solar Hot Water
(b) Others (as required)

AUDITOR CONTROLLED TEXT
(a) Comments
(b) Check-a-Text

Figure 2 (Concluded).

7. Reasonableness checks are built into the process and human intervention is available at various steps in the process.

8. The report processor draws on hundreds of tailored paragraphs to make the final product look like and

read like a custom written document. Text limited to relevant material makes the report sector specific. The auditor can insert comments, and the report generator integrates them appropriately into the text. Recommendations are presented in computer generated sentences rather than in a straight tabular form.

THE AUDIT PROCESS USING XENCAP^{tm}

Figure 3 shows the overall flow of the XENCAP^{tm} process which includes:

1.0 The Pre-audit. In order to aid the auditor in efficiently conducting the audit, preliminary data about the facility to be audited are processed. In addition to utility billing history, a dozen or so questions which categorize the building, the business type, and the various end uses of energy are collected either by a questionnaire or by telephone interview. With these data, the program prepares a pre-audit report which includes customer data, a normalized energy analysis and a preliminary end-use breakout. Using a linear programming model, the likely state of energy usage as compared to the database is computed. See Figure 4.

2.0 The Audit Data Collection. Armed with the pre-audit data, the auditor visits the site to be evaluated and fills out the appropriate forms. The forms, designed to permit the auditor flexibility, guide his data taking to insure that (a) all necessary data are collected, and (b) superfluous data collection is minimized or eliminated. The design of XENCAP^{tm} does not require all forms to be completed, only those for which recommendations are contemplated. Thus, if no building shell measures are to be recommended, no shell data are required. Where a particular piece of information is unavailable, the program database makes a statistically sound assumption, permitting the analysis to be completed.

3.0 Data Entry. The audit data are entered into the system via computer terminal or a micro-computer. At entry, all of the data are checked for reasonableness and a diagnostic report is generated. Based on over 500 entry level checks, a series of warning or fatal errors are generated. Warning errors permit the audit to be run, but with either a default value or an alert to the auditor as

THE XENCAP™ AUDIT PROCESS

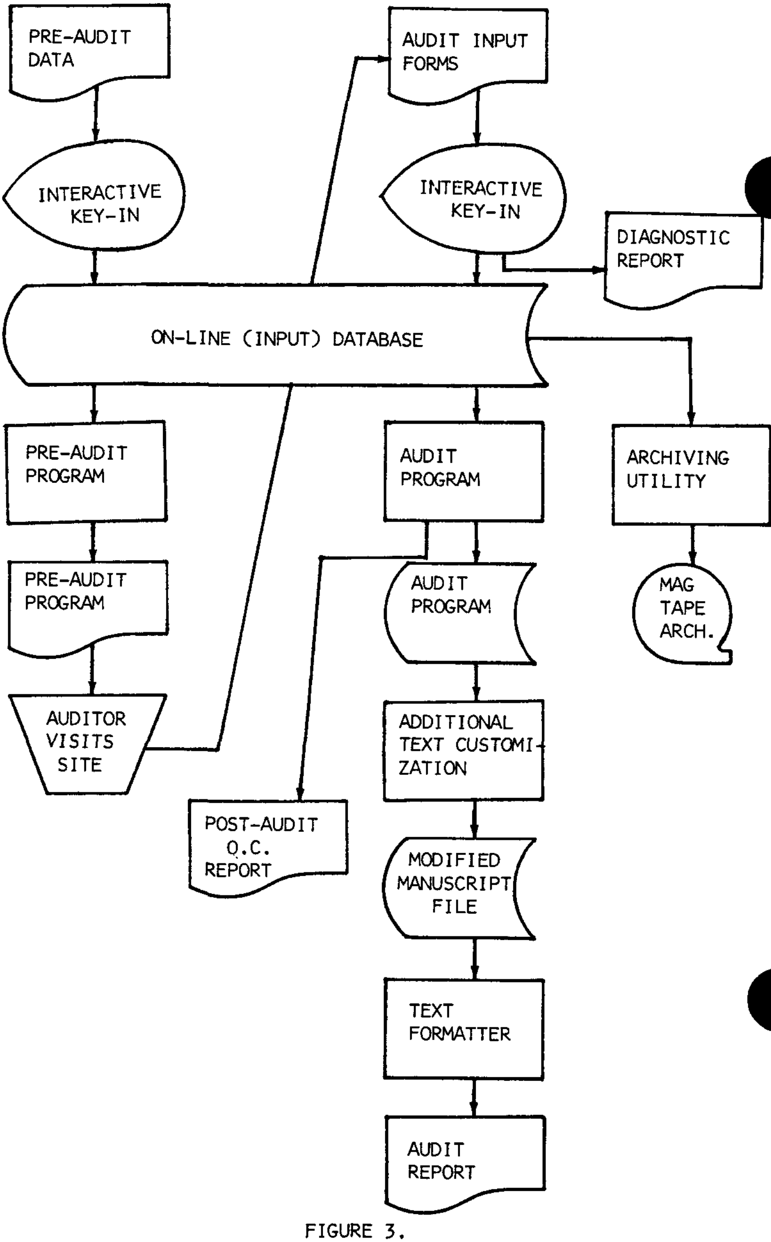

FIGURE 3.

PRE-AUDIT END USE ANALYSIS

III. End Use Estimates

End Use	Source	Cost	%	MMBTU	%	MBTU/ Sq Ft	State
Space Htg	Nat. Gas Oil	$250,000	26	27,740	29	139	High
Cooling	Elect.	$ 53,912	6	3,680	4	18	Normal
Lighting	Elect.	$ 95,224	10	6,500	7	33	Normal
Hot Water	Nat. Gas	$ 28,125	3	3,750	4	19	Normal+
Cooking	Nat. Gas	$ 20,099	2	2,680	3	13	Normal
Refrig.	Elect.	$ 34,638	4	2,364	2	12	Normal
Outdoor Lighting	Elect.	$ 11,720	1	800	1	4	Normal
Process	Elect. Nat. Gas Propane	$446,644	46	47,455	49	238	Normal
Misc.	Elect.	$ 34,638	4	2,364	2	12	Normal

Figure 4.

to an unexpected condition. Fatal errors inhibit the audit and note an almost certain error in the data. Examples of each error type are as follows:

***INPUT ERROR DIAGNOSTIC REPORT
FOR
ACCT. NO. 87267011***

WARNING NUMBER 1304 ON FORM HEAT-1

No combustion efficiency was entered for heating unit #1. A default value will be calculated by the program.

FATAL ERROR NUMBER 2200 ON FORM TEMP-1

There must be at least one temperature zone entered for the facility.

After all the data have been entered correctly, the audit is ready to run.

THE AUDIT PROGRAM

Based on information entered, using the relevant weather data, costs, etc., the audit software processes the complete audit report, analyzing, in detail, each of the appropriate measures. The program computes energy and cost savings, generates a cash flow analysis, selects the proper text and inserts and refines the end-use analysis using the auditorderived data.

To assure no double counting, a hierarchical implementation strategy is assumed. Because the savings on certain measures depend on implementation of others, we assume that measures are implemented in order of increasing payback.

For each measure, in addition to savings, implementation costs are computed. For full analysis measures, a cost is presented. For measures for which there are insufficient data to completely analyze the cost, a cost range is presented.

Once the computation has been completed, the tentatively recommended measures are reviewed for acceptability by the software on the basis of payback, saving significance and technical relevance based on preferred alternates.

Finally, the qualified measures and other results are assembled into a complete report typically between 30-100 pages in length. The report outline includes:

Table of Contents
List of Figures
Chapter I - Executive Summary
Chapter II - Energy Usage Analyses
Chapter III - Recommended Measures
Chapter IV - Miscellaneous
Appendices

The report text is highly tailored and unique to the facility being audited. Specific direction sentences are computer generated. See Figure 5. The auditor may add his own comments, and that text is integrated into the report as well. The resulting energy audit looks and reads like a professionally prepared manual product.

Once the report is prepared, the computer generates for the auditor a post-audit quality control report which summarizes the audit results and flags any unusual conditions, such as larger or smaller than usual savings.

THE DATA

All of the significant data concerning the audit are stored in a highly efficient, variable-record-length format. This database, combined with XENCAP^{tm}'s built-in database management capability, allows the user to examine the accumulated data in a variety of ways for analysis and program management of the subsequent results. Of particular significance to many XENCAP^{tm} users is the ability to understand, in detail, the energy end use of commercial/industrial customers, to evaluate the real potential for conservation or load reduction and even to identify marketing targets for new product or services.

A number of electric utility users are incorporating the audit data into their end-use based load forecasting models.

CONCLUSIONS

In every field, and energy auditing is no exception, a significant technical improvement portends important change. From the promulgation of automated industrial and commercial audit systems, the following can be expected:

1. The cost of such audits will be significantly lowered. The reduction in professional time alone will reduce cost as much as ten fold. Mean time on site with XENCAP^{tm} averages less than two hours, and total preparation to final report is less than four hours. Contrast this with the 40-80 hours currently reported by utilities for similar manual audits.

Unless items stored on the premises demand otherwise, it is not necessary to maintain occupancy temperature during periods that a facility is completely or nearly vacant, i.e., on nights or weekends. A temperature high enough to keep pipes from freezing and, as necessary, protect the contents of the building is all that is required. For every 10°F reduction, energy savings of approximately ten percent will be achieved.

Because buildings will retain heat for a period of time, the temperature can be set back an hour or so prior to closing and allowed to drift down without creating uncomfortable conditions. It may be necessary, however, to initiate warm-up prior to scheduled full occupancy in the morning, particularly on the coldest winter days. The exact timing of setback/setforward must be determined by experimentation.

If an area of the building is not completely vacant at the end of the day, but rather staffed by a small number of people, i.e., cleaning crew, a modified temperature reduction would still be in order, with the full setback delayed for the appropriate period of time. The details of the recommendation are shown in Figure 9. No additional equipment is required to implement this recommendation in areas so designated in Figure 9. You may, however, wish to consult a heating/air conditioning engineer or contractor regarding exact operation of your existing controls.

It is recommended that a seven-day clock system with dual setpoint thermostats be installed for the area(s) as designated in Figure 9. This system allows different setback schedules by day of the week. A qualified heating or controls contractor cam implement this recommendation.

Zone	Action	Equipment Needed	Est. Costs	Est. Savings
Stock Room	Lower unoccupied heating temperature to 65°F for 12 hrs/day, 6 days/wk; 24 hrs/day, 1 day/wk	None	$ 0	$111
Retail Sales	Lower unoccupied heating temperature to 65°F for 12 hrs/day, 6 days/wk; 24 hrs/day, 1 day/wk	3 7-day clock thermostats	$1,000	$544

(FIGURE 9.)

Figure 5.

2. The audit market will be broadened. Smaller firms can be expected to justify audits as long as the expense is properly scaled to their energy costs. More audits were done with XENCAP^{tm} in the past year than were completed by our firm by conventional means in the previous seven.

3. The skill level to perform satisfactory audits will be reduced. While this may threaten some engineers, a more positive view is that they will be freed to use their talents more productively, not in performing rate calculations and report writing.

4. The interrelation between the audit, load forecasting, and utility marketing, will be exploited by the creation of a comprehensive and detailed commercial/industrial energy database.

Energy auditing, as we currently define it, is a product of the rapidly escalating price of energy and the hunger for information as to how to control its impact. It was inevitable that, with conventional approaches reaching less than three percent of the commercial/industrial market, and given the rapid development of computer and software technology, an automated process would be developed. XENCAP^{tm} is the current state of the art in that development process.

COMPREHENSIVE ENERGY ANALYSIS WHAT IT IS OR SHOULD BE

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Some of the best and surest investments available to today's building owner are investments in energy conservation. Returns of 50 to 60 percent are not unusual. With energy costs in office buildings now running over $1.72 per square foot annually (1981 US average), they are the largest single item on the average building's expense statement, even larger than real estate taxes.

Energy expenses account for 38 percent of operating expenses and consume 18 percent of gross rental income. If the building owner pays the utility bills, this is obviously a matter of great concern to him. Even if the building owner "passes through" these costs to his tenants, he must still be concerned with energy conservation because tenants are growing wiser about the impacts of pass through costs. Tenants have begun to shop around for energy efficient office space and many new leases have caps limiting the amount of costs that may be passed through.

Thus, all owners of office space are concerned with controlling and reducing energy expenditures whether they pay the utility bills or pass them through to tenants. Just to stay competitive, owners will have to select and invest in the most cost-effective of a variety of energy conservation opportunities. Many energy products and services, some new and some old, are clamoring for the attention of today's building owner. How can he be sure of selecting the best investments from a sometimes bewildering assortment?

One answer to that is to engage an energy consultant to conduct a thorough "physical examination" of his building and to recommend the best steps to take toward energy conservation. Many outcomes are possible, each with its own set of economic consequences. The economic law of diminishing returns applies to increasing investments in energy conservation, and thus a phased program of implementation should be recommended. Many energy conservation measures may require little or no capital outlay by the owner because some may be suggestions for operations and maintenance improvements while others may be investments that could be made through third-party financing.

The subject of this paper is the identification and selection of Energy Conservation Opportunities (ECO's) which will maximize the owner's rate of return. The Hirshhorn Museum and Sculpture Garden, a part of the Smithsonian Institution in Washington, DC will be used as an illustration.

Since the project objective is to maximize the rate of return, subject to funding limitations, a thorough and comprehensive approach must be taken to assure consideration of all possible alternatives. A complicating factor is the fact that a building is a system whose component parts interact in very complex ways. As a result, ECO's cannot be evaluated alone but only in concert with one another so that interactive effects can be recognized and accounted for. The use of a sophisticated building energy simulation program, such as DOE 2.1, is necessary to quantify the interactive effects. DOE 2.1 gives the user many answers, including frequently unexpected ones, but more than that it can lead the experienced user to pose additional questions, that might otherwise not have been asked, stimulated by the answers received from the simulation program.

A multi-disciplinary team consisting of an engineer and an architect spent several days at this facility, an art museum, observing and recording lighting equipment and light levels, interviewing operating personnel as to building schedules, problems with equipment, etc., and examining heating, ventilating, and air conditioning equipment. Being a museum, lighting levels and humidity control were of great importance. The variation in building occupancy presented an additional complicating factor.

After lighting, occupancy, HVAC and other schedules were developed and approved, five years of energy billing data was collected and analyzed. Concurrently, a testing and balancing firm was contracted to measure the actual performance of the air moving equipment, exhaust fans, air delivery from ducts, circulating water pumps, preheat and steam reheat coils, chiller, cooling tower, and condensate pumps. Finally, 67 ECO's in four major categories - Operation and Maintenance (10 ECO's), Building Envelope (8 ECO's), Lighting and Electrical (21 ECO's), and HVAC (28 ECO's) were identified.

At this point, an Interim Report was submitted to the owner's staff for review and comments. Corrections to the Report were made concerning certain ECO's primarily in the area of O & M, were immediately adopted by the owner thus removing them from further consideration.

At the same time, DOE 2.1 computer simulations of the existing conditions were performed. The early runs were validated against actual energy consumption and demand and where discrepancies existed, additional investigations were performed to provide explanations. Each subsequent iteration came closer to actual and the final iteration varied from actual by less than one percent, indicating a five year average energy consumption of abour 400,000 BTU/GSF/year. As validated, the simulation now faithfully modeled actual building performance and could be relied upon to accurately predict the effects of various ECO's on building energy performance.

This step, the validation of a simulation program, is one of the most important steps in the preparation of a Comprehensive Energy Analysis but it is also one of the most difficult and most often omitted steps. The only other activity which demands a similar level of sophistication on the part of the user is the interpretation of results.

The skill of interpretation of results comes only after many hours of study of the program, even including going deeply into the program logic to gain a greater understanding. Being able to interpret results allows one to more quickly validate the program and allows one to readily identify unexpected answers and ask the right questions to more thoroughly analyze building energy performance and the effects of ECO's.

Each of the individual ECO's were then subjected to an individual energy analysis using an assortment of manual calculation methods and computerized parametric studies. The results of the energy analysis along with the estimated cost of implementation are used in the next step, economic analysis. A Savings-to-Investment Ratio

(SIR) was computed for use as a selection criterion.

The SIR is a numerical ratio calculated with the reduction in energy costs, net of increased non-fuel operation and maintenance costs, as the numerator, and the increase in investment cost, minus increased salvage values, plus increased replacement costs, as the denominator. An SIR greater than one means the investment is cost-effective; the higher the ratio, the greater the dollar savings per dollar spent. Only present values are used in computing an SIR. Please refer to Figure 1 for an illustration of the individual ECO analysis procedure.

From the individual ECO analysis, sequential grouping of ECO's was developed in order to optimize the reduction in annual energy consumption versus cost. These Groups were based on a combination of ECO's which complemented each other, providing the lowest energy consumption. The first two ECO Groups consisted of ten lighting and electrical ECO's and three envelope ECO's, each with an SIR of greater than five. These two Groups minimized energy consumption which was due to internal loads and the transfer of heat and moisture through the building envelope. These two Groups were incorporated into every other ECO Group which was considered.

The goal of the grouping process was to include, with a few exceptions, only those ECO's with an SIR over five. Interestingly, some ECO's which did not display an SIR of over five, the cut-off point, did possess SIR's of more than five when assembled into Groups. This was due to the complementary nature of certain ECO's.

The energy analysis of each ECO Group was conducted using the DOE 2.1 computer program. After completion of the ECO Group computer simulations, Life Cycle Cost Analysis of ECO groupings are accomplished to determine their economic viability.

In Life Cycle Cost Analysis, all of the costs associated with owning and operating a building are taken into account over a reasonable study period, usually the projected building life and compared to the similar information for energy conservation opportunities. A number of different results from the Life Cycle Cost Analysis can give the owner different views of the cost-effectiveness of alternatives; net present value, Savings-to-Investment Ratios, return on investment, discounted payback, periods and internal rate of return. Each as a different usefulness in displaying the results to different owners depending on their financial criteria. For federal government projects, the Savings-to-Investment Ratio and net present value gives the owner the best information on cost-effectiveness of any energy conservation opportunity

IDENTIFICATION

Title: HVAC EOM-14A

Brief I.D. Statement: Install three-way valves on piping to chilled water coils.

Detailed I.D. Statement:

- Function: Reduce chilled water circulated through cooling coils.
- Principle of Energy Savings: Reduce chilled water pumping and reheat requirements.
- Impact on Other Systems: Requires controls modifications.
- Life Expectancy: 20 years.
- Aesthetic Impacts: None.

Operation and Maintenance Requirements: Additional maintenance of controls.

Specialized Training and Material Requirements: Initial training on controls operation.

IMPLEMENTATION STATEMENT

Construction

- Time of Year: Winter.
- Phasing: None.

Impact on Personnel

- Moving of Equipment and Occupants: None.
- Special Conditions (Off-hour work, debris control): None.

LIFE-CYCLE IMPACT

Money	Existing Conditions	After Implementation	
First Costs			
1. Estimated Construction Award Amount*	0	$54,000	*Includes 7% contingency and no escalation
2. Design/Supervision/Award	0	5,400	
3. Moving Expenses	0	0	
4. Other -	0	0	
5. Total First Costs	0	$54,400	
Recurring Costs			
1. Present Value of Energy Costs	$13,723,400	$12,415,900	
2. Present Value of Maintenance Costs	0	11,654	
3. Present Value of Replacement Costs	0	15,350	
4. Special Training and Material Costs	0	935	
5. Total Present Value of Recurring Costs	$13,723,400	$12,443,839	
Total Life Cycle Cost	$13,723,400	$12,491,500	
Cost Factors			
Savings to Investment Ratio		20.5479	
Energy Cost Savings Ratio		0.0963	
Energy Savings to Investment Cost Ratio		1.6501	

Energy	Site Energy (BTU/GSF/Year)	Source Energy (BTU/GSF/Year)	Annual Energy Cost ($)
Existing Conditions	428,504	868,218	$932,115
After EOM Implementation	388,536	779,219	842,349
Total Annual Energy Savings	39,968	88,999	89,766
Annual Electricity Savings	17,326	58,887	46,064
Annual Steam Savings	22,642	30,112	43,702
Electricity Demand Reduction (Total KW)	0		0

FIGURE 1

IDENTIFICATION

Title: ECM Group 8B

Brief I.D. Statement: HVAC ECM's #7, 8, 10, 12 & 14A and ECM Groups 1, 2 & 3

Detailed I.D. Statement:

- Function: Reduce air quantities with VAV system, cooling requirements with 3-way valves on cooling coils, and face and bypass dampers, and purchased steam consumption by using natural gas steam boilers.

- Principle of Energy Savings: Lower fan energy, cooling and heating requirements with VAV. Lower cooling and reheating requirements with 3-way valves on cooling coils and face and bypass dampers.

- ...pact on Other Systems: Lower cooling, heating and heating energy.

- ...e Expectancy: See Individual ECM's.

- Aesthetic Impacts: None.

Operation and Maintenance Requirements: Maintenance of VAV equipment, 3-way valves, dampers and natural gas boilers.

Specialized Training and Material Requirements: Operation of boilers and other portions of system.

IMPLEMENTATION STATEMENT

Construction

- Time of Year: Winter for HVAC equipment.
- Phasing: Phase I - ECM Groups 1 & 2; Phase II - ECM Groups 3 & 8B.

Impact on Personnel

- Moving of Equipment and Occupants: Some required for ECM Groups 1 & 2.

- Special Conditions (Off-hour work, debris control): Debris control in ECM Groups 1 & 2.

LIFE-CYCLE IMPACT

Money	Existing Conditions	After Implementation	
First Costs			
1. Estimated Construction Award Amount*	0	$1,043,300	*Includes 7% contingency and no escalation
2. Design/Supervision/Award	0	95,000	
3. Moving Expenses	0	44,000	
4. Other - Cleanup Work	0	12,000	
5. Total First Costs	0	$1,194,300	
Recurring Costs			
1. Present Value of Energy Costs	$13,723,400	$5,009,630	
2. Present Value of Maintenance Costs	0	124,787	
3. Present Value of Replacement Costs	0	175,997	
4. Special Training and Material Costs	0	7,477	
5. Total Present Value of Recurring Costs	$13,723,400	$5,317,891	
Total Life Cycle Cost	$13,723,400	$6,392,760	
Cost Factors			
Savings to Investment Ratio		6.8605	
Energy Cost Savings Ratio		0.6361	
Energy Savings to Investment Cost Ratio		0.4965	

Energy	Site Energy (BTU/GSF/Year)	Source Energy (BTU/GSF/Year)	Annual Energy Cost ($)
Existing Conditions	428,504	868,218	$932,115
...r ECM Implementation	183,440	408,244	336,747
... Annual Energy Savings	245,064	459,974	595,368
...l Electricity Savings	52,975	180,050	78,145
Annual Steam Savings	266,235	354,070	516,408
Electricity Demand Reduction (Total KW)	643		62,693
Annual Natural Gas Savings	-74,146	-74,146	-61,878

FIGURE 2

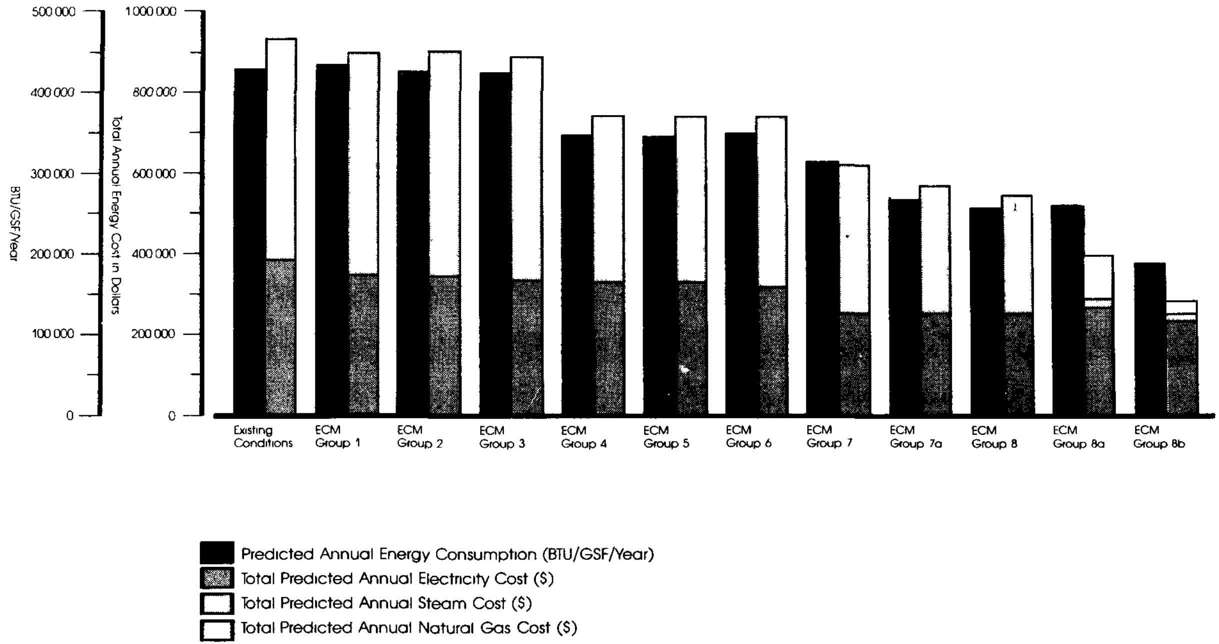

FIGURE 3

Summary of Predicted Energy Consumption and Cost under consideration. Private investors usually prefer a rate-of-return measurement. The rate-of-return of the best ECO Group in the Hirshhorn Project was over 49 percent.

The recommended ECO Group was Group 8B which was comprised of ECO Groups 1 and 2 plus six individual HVAC ECO's. Please see Figure 2 for the worksheet for this group. The SIR for this Group is 6.86, over the cut-off point by a comfortable margin. Figure 3 illustrates the energy consumption and energy costs predicted for all the ECO Groups.

After a collection of ECO's are selected which meet the owner's financial criteria and maximizes his return-on-investment, the next phase is implementation. This may be accomplished through the usual channels of owner financing but other options exist. A 49 percent rate-of-return is large enough to attract third-party financing firms who will pay for the energy improvements and share the savings with the building owner. One advantage of such a rigorous analysis as was described in this paper, is that such firms will frequently accept the report as a basis for negotiating an implementation contract.

In summary, some of the best investments available to today's building owner are investments in energy conservation, and very high rates-of-return are possible. However, a comprehensive approach to the building energy analysis is necessary to optimize the rate-of-return. Since many individual energy conservation opportunities, if implemented, will interact with each other in positive ways, a total approach using a building energy simulation program is required. Individual ECO's should be packaged in complementary groups so that interactive effects can be quantified and kept positive. Surprising results may occur that lead the investigator to pose new questions or solutions. A comprehensive approach will yield optimal solutions and may even attract outside financing.

SIMPLIFIED PROCEDURE FOR CALCULATING THE TECHNICAL PERFORMANCE OF CONVENTIONAL AND ADVANCED SPACE CONDITIONING EQUIPMENT

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INTRODUCTION

Currently, there are several sophisticated computer programs available for estimating the technical performance of space conditioning equipment at the system level. However, the use of these programs requires excessive input preparation time and skills, access to large computers and computer usage costs. Moreover, these computer programs cannot assess the performance at the sub-system level such as the heat transfer characteristics of condensers and evaporators. Procedures suitable for manual calculation of technical performance of space conditioning equipment exist such as the degree-day method, which has been used for several years by energy suppliers to estimate energy usage for residential buildings. This method is inherently inaccurate because it does not account for essential elements of energy calculations such as: coincident hourly weather conditions, parasitic power usage and defrost degradation.

Due to the shortcomings of existing performance estimation procedures the Gas Research Institute sponsored a research effort to develop a simplified performance evaluation procedure that could be used to compare the technical and economic performance of existing and advanced residential space conditioning technologies. This paper presents the objective of the research effort, the unique features of the simplified performance evaluation procedure and provides a description of the procedure. The details of the research are documented.(1)

OBJECTIVE

The objective of the research effort was to develop a simplified step-by-step manual performance evaluation procedure that could be used to compare the technical and economic performance of any competing space conditioning technology within the residential market. Specifically, the procedure would be designed to handle the following parameters:

- Conventional space conditioning equipment combinations
- Advanced space conditioning equipment including gas-fired heat pumps
- Sub-system operating characteristics
- Annualized life-cycle cost.

UNIQUE FEATURES

The procedure developed as a result of this research effort is a simple, step-by-step manual method for accurately estimating equipment performance. This procedure is unique in that it can, without modification, handle the following parameters:

- Conventional space conditioning equipment combinations
  - -- Central split or packaged cooling equipment
  - -- Electric heat pumps
  - -- Gas and oil furnaces with central electric air conditioning
- Advanced space conditioning equipment
  - -- Gas-fired heat pumps
  - -- Hybrid electric heat pumps
  - -- Multi-speed and fully modulating electric heat pumps
  - -- Condensing furnaces
- Equipment operating characteristics
  - -- Conditions at evaporator and condenser

- -- Refrigerant performance
- -- Defrost degradation
- -- Cycling degradation
- -- Parasitic power losses
- -- Auxiliary heating control strategies

- Economic considerations
    - -- Equipment installed first cost
    - -- Maintenance cost
    - -- Separate book lives of heating and cooling components of space conditioning system combinations.

The procedure is applicable to any single-family residential building at any location where "Bin" temperature and energy price data are available.

The performance procedure provides the following end results for heating and cooling seasons:

- Seasonal building loads
- Seasonal primary equipment energy consumption
- Seasonal parasitic energy consumption
- Seasonal auxiliary heating energy consumption
- Seasonal total energy consumption
- Seasonal COPs

These results are used to compute and compare the annualized life-cycle costs of competing space conditioning equipment over any time period.

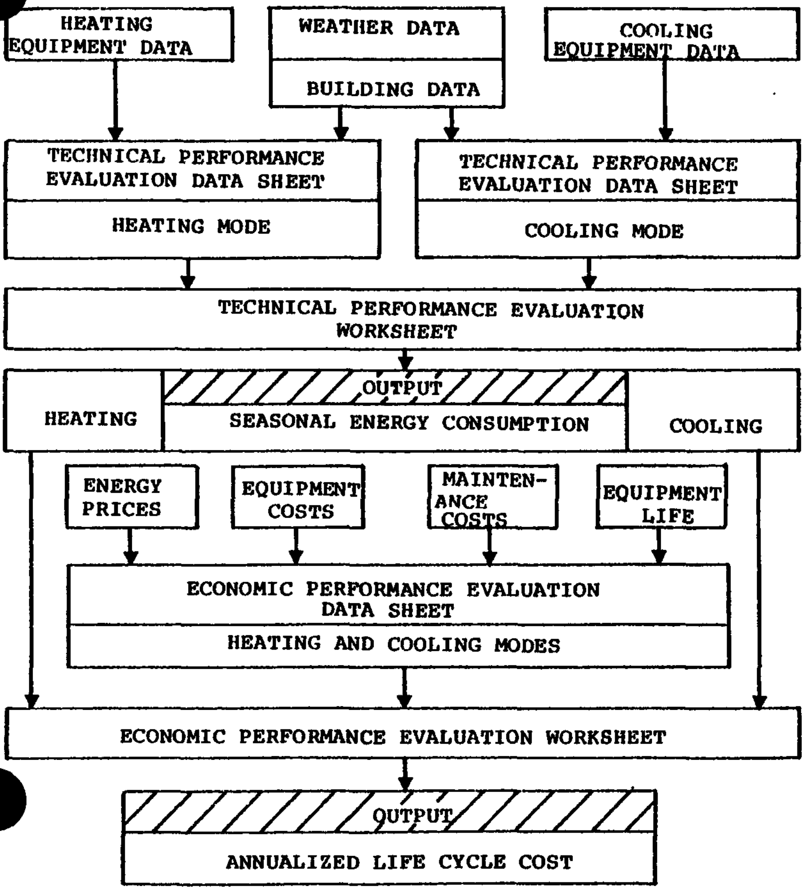
The procedure is performed using specific tools, i.e., data sheets and worksheets. The data sheets are designed to transform raw data such as equipment specifications provided by manufacturers into a consistent format for direct use in the procedure. The worksheets constitute the technical and economic components of the procedure and allow performance evaluations to be made at each Bin temperature.

PROCEDURE DESCRIPTION

The procedure consists of two components, a technical performance evaluation and an economic performance evaluation that are performed sequentially as shown in Figure 1. Equipment technical performance data, weather data and building load data are entered into technical

FIGURE 1

PERFORMANCE EVALUATION PROCEDURES FLOW CHART



performance evaluation data sheets. Data from these sheets are used in the technical performance evaluation worksheet. The output from this worksheet is seasonal energy consumption.

Energy price data, equipment first cost data, maintenance cost data and equipment life data are entered into the economic performance evaluation data sheet. Data from these sheets and the seasonal energy consumption values are used in the economic performance evaluation worksheet. The output from this worksheet is annualized life-cycle cost.

Technical Performance Evaluation

The procedure based on the ASHRAE Bin method assumes a given design heating load and a given design cooling load.(2) Combination heating/cooling equipment such as heat pumps are sized on the cooling load.

The technical evaluation consists of 33 steps described below to be used with the technical performance evaluation worksheet developed.(1)

Load Computation: In Steps 1, 2 and 3, heating and cooling loads are computed for each Bin mean temprature.

Step 1 - Bin Hours Per Year: Mean ambient dry bulb temperatures for each 5-degree temperature bin are noted for the location under consideration.

Step 2 - Bin Hours Per Year: The number of hours at each Bin temperature is obtained from National Weather Service records or Air Force Weather Data.(3)

Step 3 - Building Load Per Hour: Heating and cooling loads are calculated for each Bin from design heating loads. (Design load/oF t x Outdoor-Indoor Temperature Differential.)

COP Computation: In Steps 4 through 15, the ideal and attained COP values are computed.

Step 4 - Capacity at Ambient: Heating and cooling capacities at outdoor conditions are obtained from equipment performance specifications. For modulating equipment, the capacity selected from equipment specifications is the one that is closest to the load requirement. For two-speed equipment, the capacity selected from equipment specifications is the one that is closest to the load at the lowest speed available.

Step 5 - Listed COP: The coefficient of performance is obtained from equipment manufacturers' specifications. COP can be derived from capacity and power input curves from data sheets. COP equals capacity divided by power input (in the same units). Manufacturers' listed COPs may not account for any parasitic power losses due to indoor or outdoor fans. Parasitics will be accounted for in Step 27.

Step 6 - Evaporator Temperature Gradient: Evaporator temperature gradient is obtained from equipment manufacturer. For modulating equipment, evaporator temperature gradient equals load to capacity ratio times the value for evaporator temperature gradient for conventional single-speed equipment.

Step 7 - Evaporator Refrigerant Temperature: Temperature of refrigerant in evaporator equals the difference of temperature gradient (Step 6) from ambient temperature (Step 1) for heating and from indoor temperature for cooling.

Step 8 - Condenser Temperature Gradient: Condenser temperature gradient is obtained from manufacturer. Default value for heating is twice evaporator temperature gradient (2 x Step 6).

Step 9 - Condenser Refrigerant Temperatures: Temperatures of refrigerant in condenser equals room temperature plus condenser temperature gradient for heating or condenser temperature gradient minus ambient temperature for cooling.

Step 10 - Absolute Temperature of Refrigerant in Evaporator: Absolute temperature equals 459oF plus evaporator temperature.

Step 11 - Absolute Temperature of Refrigerant in Condenser: Absolute temperature equals 459oF plus condenser temperature.

Step 12 - Ideal Carnot COP of Compressor Loop: Ideal Carnot COP for heating and cooling is computed using absolute temperatures of refrigerant in condenser and evaporator.

Step 13 - COP Cycling Degradation: Cycling occurs whenever the equipment capacity exceeds building load requirement. (Step 4 divided by Step 5) The percentage degradation of COP in heating and cooling modes is obtained from equipment manuafacturers.

Step 14 - Net COP: Net COP is the ideal COP degraded for cycling effects.

Step 15 - COP Attainment: COP attainment depends on refrigerant properties.

Compressor and Heat Engine Energy Consumption: Steps 16 through 21 result in the computation of annual primary equipment energy consumption.

Step 16 - Energy Usage Per Hour: Energy used by the compressor loop equals capacity of equipment divided by actual COP of compressor loop. (Step 4 divided by Step 15)

Step 17 - Defrost Penalty: Frosting of the evaporator coils usually occurs for heat pumps at ambient temperatures below 35oF. Energy is used to defrost the evaporator coils. Defrost degradation is obtained from equipment manufacturers.

Step 18 - Energy Consumption Per Hour: Energy consumption per hour is the energy usage per hour (Step 16) times defrost penalty (Step 17).

Step 19 - Annual Consumption: Annual consumption is the energy consumption per hour (Step 18) times the Bin hours per year (Step 2). Above the balance point the annual consumption is decreased in the ratio of load to capacity at each Bin temperature.

Step 20 - Electricity Consumption: Electricity consumption is the electrical energy input per year (from Step 19) for heating and cooling except auxiliary power usage and parasitic power usage.

Step 21 - Natural Gas Consumption: Natural gas consumption is the natural gas input per year (from Step 19) for heating and cooling except auxiliary power usage and parasitic power usage.

Parasitic and Auxiliary Energy Consumption: Steps 22 through 26 compute annual parasitic and auxiliary energy consumption.

Step 22 - Parasitic Power Consumption: This is annual energy usage for condenser fans, cooling towers, evaporator fans, power vents, pumps, etc., provided by equipment manufacturer.

Step 23 - Auxiliary Heating Requirements: Auxiliary heating is usually required in the heating season whenever the building load requirements exceed the equipment heating capacity. Auxiliary energy for heat pumps is the load (Step 3) minus the capacity at each Bin (Step 4).

Step 24 - Annual Auxiliary Equipment Energy Consumption: Annual energy consumption by auxiliary heating equipment is the auxiliary energy requirements (Step 23) times the Bin hours per year (Step 2).

Step 25 - Auxiliary Heating Electricity Consumption: Auxiliary heating electricity consumption is electricity consumption per year (from Step 24) for auxiliary heating equipment.

Step 26 - Auxiliary Heating Natural Gas Consumption: Auxiliary heating natural gas consumption is natural gas consumption per year (from Step 24) for auxiliary heating equipment.

Furnace Energy Consumption: Steps 27 through 30 compute annual energy consumption by furnaces.

Step 27 - Furnace Heating Part Load Fraction: This is the ratio of the building load to the equipment heating output.

Step 28 - Furnace Efficiency at Part Load: Furnace efficiency ratings at part load is obtained from furnace manufacturer.

Step 29 - Furnace Energy Usage: Energy consumption by furnace is the load (Step 3) divided by the part load efficiency (Step 28).

Step 30 - Annual Energy Usage by Furnace: This is natural gas or fuel oil consumption per year (Step 29 times Step 2).

Total Energy Consumption, Load and COPs: Steps 31 through 33 compute total annual energy consumption, total annual building load, and the COP by Bin.

Step 31 - Total Annual Energy Input: Total annual energy consumption equals Step 19 plus Step 22 plus Step 24 plus Step 30.

Step 32 - Total Annual Building Load: Total annual building load equals Step 2 times Step 3.

Step 33 - COP by Bin: Annual COP for each temperature Bin equals the total annual building load divided by the total annual energy input (Step 32 minus Step 31).

Annual heating and cooling energy consumption and building loads are computed by adding Bin data horizontally from left to right for all Bin Temperatures.

ECONOMIC PERFORMANCE EVALUATION

This procedure calculates the annualized life-cycle cost of owning and operating space conditioning equipment and relies on annual energy consumption of heating and cooling equipment from the technical performance evaluation described above. This evaluation procedure consists of 13 sequential steps described in detail in reference 1. Seasonal operating costs for primary equipment, parasitics and auxiliary equipment are computed using the appropriate energy prices for the location. Operating costs together with equipment first costs, replacement costs and maintenance costs are used to compute the annualized life-cycle cost.

SUMMARY

Comprehensive step-by-step manual procedures are developed to enable estimation and comparison of the technical and economic performance of conventional and advanced space conditioning equipment for residential applications. The technical performance procedure is based on the ASHRAE Bin method and, therefore, can be used for estimating performance at virtually any location for which Bin weather data is available. The procedure is applicable to single-speed, multispeed, and fully modulating compressors, hybrid heat pumps, gas-fired heat pumps, gas-fired condensing furnaces, and all conventional heating/cooling equipment.

Performance degradation due to cycling, defrosting, and refrigerant characteristics can be determined by this procedure. Annual energy consumption for heating and cooling is determined by energy-source type in terms of million Btu per year. Annual energy consumption is entered into the economic performance procedure to determine the annualized life-cycle cost of the heating/cooling equipment combination. Life-cycle cost is computed over any period using projected energy cost, equipment-first costs, maintenance costs, operating costs, and book life.

ACKNOWLEDGEMENTS

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-- <u>SMALL AND DISADVANTAGED BUSINESS UTILIZATION SPECIALISTS</u> (A state-by-state listing of small business specialists including telephone numbers)

-- <u>SMALL BUSINESS SUBCONTRACTING DIRECTORY</u> (A state-by-state listing of DOD prime contractors)

-- <u>GUIDE TO THE DEFENSE ACQUISITION REGULATION FOR SMALL/SMALL DISADVANTAGED/WOMEN-OWNED BUSINESS</u>

- <u>SELLING TO THE UNITED STATES AIR FORCE</u>

Office of Small and Disadvantaged Business Utilization
HQ USAF/RDB (Pentagon Room 4C255)
Washington, DC 20330 Telephone: (202)697-5373

- <u>SELLING TO AIR FORCE PRIME CONTRACTORS</u>

AFCMD Pamphlet 70-30
Small Business Office
Air Force Contract Management Division/BCE
Kirtland AFB, NM 87117 Telephone: (505)844-6684

3. Where the Buying is Done. The <u>Selling to the Military</u> pamphlet, mentioned earlier, provides complete addresses and phone numbers of the major military buying offices and research and development activities. A close review of this pamphlet will identify the principal interest of each of

these offices.

4. Making Your Capabilities Known.

- Once you have identified the military contracting offices responsible for the products or services you can furnish, you will want to submit completed copies of:

-- The Bidder's Mailing List Application, Standard Form 129, and

-- The Bidder's Mailing List Application Supplement, DD Form 558-1.

(These forms can be found between pages 6 and 7 of Selling to the Military, or may be obtained from any military contracting office.

There is no centralized point of contact in the Defense Department to make your capabilities known, so it will be necessary for you to send a copy of your Standard Form 129 to each contracting office with which you wish to do business. Each contracting office that has your firm on its bidder's list will forward "Invitations for Bids" (IFBs) or "Requests for Proposals" (RFPs) as requirements develop for supplies or services you have offered.

- While the Defense Department follows established competitive contracting procedures for awarding contracts, in some cases contracts are awarded based upon unsolicited proposals.

-- An unsolicited proposal is a written offer to perform a proposed task, submitted to the Government by a prospective contractor without Government solicitation, with the objective of obtaining a contract.

-- Specific guidance on how to structure and submit unsolicited proposals can be found starting on page 89 in the Selling to the Military pamphlet, and on page 2-11 in the booklet Selling to the U.S. Air Force.

-- Unsolicited proposals must offer significant technological promise and be original thinking by one source.

5. The Defense Acquisition Regulation. The Defense Acquisition Regulation, or DAR, is the primary and single most important regulation governing defense contracting.

- The DAR is over 2000 pages long, and contains defense contracting policies, as well as many detailed procedural and administrative requirements.

- To be a successful military contractor, you must have a working knowledge of the DAR.

- The booklet, Guide to the Defense Acquisition Regulation for Small Business, is designed to help you understand the DAR by offering explanations of the basics of doing business with DOD. This booklet is available through the DOD Office of Small and Disadvantaged Business Utilization, Pentagon Room 2A340, Washington, DC 20301.

In conclusion, we hope we've provided you with the who, where, what and how of doing business with the military. Good luck in your efforts.

VENTURE CAPITAL ENERGY PROCUREMENT BY THE MILITARY SERVICES

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"The views expressed in this article are those of the author and do not reflect the official. policy or position of the Department of Defense or the U.S. Government."

INTRODUCTION

The military services; Army, Navy, Air Force, Marine Corps and Department of Defense (DOD), own and operate over 1500 major installations in the continental United States and several hundred more in overseas locations. Each of these installations consumes a significant amount of energy. For example, a major Naval Shipyard such as Bremerton, WA consumes 3,000,000 million Btus annually at a cost exceeding $8.1 million. A large Air Force Base, Wright Patterson for example, uses 6,300,000 million Btus each year and spends $20 million for energy.

To control energy consumption and reduce energy costs, each of the services has an agressive energy conservation program. Significant reductions in energy use have been achieved. There remain, however, continuing requirements to obtain very large quantities of electrical and thermal energy. Traditionally, military installations purchase electricity from regulated public utilities wherever possible. Thermal energy is provided in the great majority of cases by a central plant, district heating system using a fossil fuel, most often residual oil, often natural gas, and least frequently coal.

With the emergence of alternate and renewable energy forms in the 1970's, and with the drastic acceleration of energy costs in 1973-74 and again in 1979-80, the military services began to seek alternatives to their classic means of obtaining energy. Because of tight budgets for capital funds and personnel ceiling constraints, the alternatives sought did not generally involve service ownership or operation of energy production facilities.

In 1978, Congress, at DOD's request, provided authority in the Fiscal Year 1979 Military Construction Authorization Act for the military services to contract for the provision of energy from renewable sources for up to 30 years. This extended authority, up from 10 years, was sought and obtained to allow the military services to contract for major investments in alternate energy production facilities, especially geothermal energy. In 1982 this authority was incorporated into formal law by inclusion in Title 10 United State Code as Section 2394 which reads in part:

> "Contracts for energy or fuel for military installations
>
> "(a) Subject to subsection (c), the Secretary of a military department may enter into contracts for periods of up to 30 years -
>
> "(1) under Section 2689* of this title; and
>
> "(2) for the provision and operation of energy production facilities on real property under the Secretary's jurisdiction or on private property and the purchase of energy produced from such facilities.
>
> "(b) A contract may be made under subsection (a) only -
>
> "(1) after the approval of the proposed contract by the Secretary of Defense; and
>
> "(2) after the Committees on Armed Services and on Appropriations of the Senate and House of Representatives have been notified of the terms of the proposed contract, including the dollar amount of the contract and the amount of energy or fuel to be determined to the Government under contract.

* Section 2689 provides authority to the Secretaries of the military departments to develop geothermal energy on military lands.

Although the impetus for creation of the authority provided under 10 USC 2394 was to allow development of geothermal energy on military lands, this new authority has and will provide for a wide range of other energy developments.

CONCEPT

The concept of Venture Capital Energy Procurement is to offer the long term energy needs of military installations as opportunities for the investment of venture capital. The military services are faced with:

- Greatly increasing energy costs
- Highly competitive requirements for available capital investment funds
- Tightly constrained personnel manning limitations
- Limited capacity for management and operation of technically complex facilities
- Pressing need to reduce vulnerability of essential mission to interruptions of energy supplies

At the same time Congress has authorized the services to offer firm, long term commitments to purchase energy. Further, the services can often offer a site for energy production facilities and in some cases can even offer an energy resource such as geothermal. The interplay of these factors results in a situation that leads the military services to a posture of procuring energy in lieu of producing it themselves.

Significant changes in technical and political factors related to the production, distribution and pricing of energy have occurred in recent years, in particular since the 1978-1980 oil crisis and the 1981 change in Federal Administration. There have been significant technology advances in the efficiency of production of energy along with new tax and regulatory policies designed to provide incentives for energy production. The combination of these factors lead to a major opportunity for private sector investment in high efficiency and alternate energy production facilities. Investment tax credits, energy tax credits - both Federal and State, accelerated depreciation rules, and resource depletion allowances all support private capital formation.

The confluence of the military services' needs with the private investment opportunity results in a concept labeled Venture Capital Energy Procurement. By offering long term contracts for energy procurement, the services provide potential investors with a firm energy market which in turn allow the securing of investment capital. Placement of this capital into high efficiency and alternate energy producing facilities results in a revenue stream which rewards the investors for their foresight and risk taking. Simultaneously, this results in a secure supply of energy for the military service at a price advantage over conventional energy supplies.

EXAMPLES

Although many of the factors listed as enhancing the concept are of recent origin the basic underlying precepts are not. There exist now successful applications of Venture Capital Energy Procurement within the services, some of which have been in place for ten years and more.

Cogeneration - Applied Energy Inc.:

The Navy, starting in 1970, signed three separate contracts for the purchase of steam at Naval installations in San Diego, CA. All three contracts are similar and were negotiated with the same contractor, Applied Energy Inc. (AEI). The contractor is a wholly owned subsidiary of San Diego Gas and Electric which is a regulated utility. SDG&E formed AEI specifically to do business with the Navy.

The relationships of the parties to the contracts are rather complicated. AEI purchases natural gas for use as fuel. The natural gas is delivered to SDG&E and is used to fire an SDG&E gas turbine, located on a Navy site, which generates electricity. The electricity is fed into the SDG&E grid and the hot gas exhaust from the turbines is delivered to AEI. AEI puts the hot exhaust through heat recovery boilers to produce steam which is then delivered to the Navy. The Navy is responsible for distribution of the steam to end users and for collection and return of condensate to AEI for which it receives a credit.

Contracts are in place at three Naval installations: Naval Training Center since January 1970, Naval Station since August 1973, and Naval Air Station North Island since January 1976. At each location AEI provides a conventional package boiler with a capacity sufficient to provide the agreed minimum steam quantity in the contract. This provides backup steam for periods when the SDG&E gas turbines might be out of service.

The Navy views these contracts as beneficial. They provide a reliable source of thermal energy in a fashion very similar to purchased electricity. In view of the long and successful term of experience with these contracts they are considered to be benchmarks for the Venture Capital Energy Procurement concept.

Geothermal - Coso - Naval Weapons Center, China Lake, C

In December 1979, the Navy awarded a unique Venture Capital contract for the development of geothermal energy from portions of the Coso geothermal resource located on the Naval Weapons Center China Lake, CA. The contract, awarded to the California Energy Company Inc (CECI), calls for the contractor to explore the geothermal resource, drill geothermal wells, construct power plants and produce electricity from geothermal steam and fluids. Electricity produced, up to 75 mega-watts (MWe), is to be delivered to the Navy and the Navy is to pay for delivered electricity on a unit cost basis. The contractor is obligated under the contract terms to make all necessary arrangements to transport electricity from China Lake to other Navy activities in the Southern California region. CECI has completed a highly successful exploratory program, with six productive wells drilled. Under present plans, deliveries of electricity will commence in 1984. The term of this contract is thirty years.

The contract is considered to be a classic example of the Venture Capital Energy Procurement concept. CECI plans to invest $10 to 20 million of venture capital funds and to assume significant development risks. The Navy in turn provides a long term commitment to pay for the delivery of electricity and provides the geothermal resource.

In Oct 1982, the Navy received bids for a very similiar development of up to 75 MWe of geothermal energy at the Naval Air Weapons Training Center, Fallon, NV. The bids are under review and a contract award is expected.

Several other very interesting Venture Capital Energy Procurement projects are currently under process of development.

Refuse Derived Fuel - Naval Shipyard Norfolk, VA:

In a project akin to Venture Capital but involving governmental funding, the Navy expects to contract with the Southeastern Public Service Authority (SPSA) of

Tidewater Virginia for the delivery of Refuse Derived Fuel (RDF) to a new heating plant to be constructed at the Norfolk Naval Shipyard. SPSA, a state chartered authority composed of 4 cities and 2 counties, plans to build a trash processing plant of 2000 tons per day capacity. The plant, expected to cost $70 million or more, will produce RDF which the Navy will commit to buy and burn. The Navy's new heating and generating plant at the shipyard is specifically designed to burn coal but will also be equipped to burn RDF. The Navy will buy RDF from SPSA at a price pegged to 85% of the equivalent fuel value of coal. Offsets will be made for the added operations and maintenance costs resulting from using RDF in lieu of coal. Further price offsets will be made to amortize the added capital costs of achieving an RDF burning capability in a coal fired plant.

In addition to the difference in the government nature of the contract, this project differs from the standard Venture Capital Energy Procurement concept in that the Navy will build and own an energy production facility. Mission requirements dictated the construction of the new plant at the Norfolk Shipyard. The RDF contract represents an add-on which gives the Navy an economical and renewable fuel source and contributes to the solution of a major waste disposal problem for Tidewater Virignia.

Trash To Steam - Philadelphia

As a result of critical solid waste disposal problems for Philadelphia, negotiations are underway between the Navy and the City of Philadelphia for a Trash-to-Steam contract. The City proposes to sponsor the construction, by a third party venture capital interest, of an 1800 ton per day trash burning plant. The plant would produce steam, which the Navy would buy for use in the Philadelphia Naval Shipyard, and electricity which would be sold to the local public utility. The Navy would lease a site immediately adjacent to the shipyard to the City for plant construction. Financing of the project which is expected to exceed $200 million, would be through a combination of municipal bonds and Venture Capital investment. The Venture Capital owner-operator of the plant would receive revenues from the sale of steam, sale of electricity, and tipping fees paid for trash disposal. A key factor in the project make-up is private ownership of the plant. This is considered to be essential so that tax benefits including investment tax credits and depreciation deductions can be obtained.

The Navy's role in this project would be limited to provision of a real estate lease and the guaranteed purchase of a specified amount of steam for the contract term, expected to be 20 years.

Concepts for Venture Capital projects are virtually unlimited. A wide range of current technologies are available and are actively being considered. Other active military projects include-

Landfill Methane - Miramar, CA

At Naval Air Station Miramar, CA near San Diego, the Navy is pursuing a unique Venture Capital Energy Procurement. For over 20 years the Navy has leased land to San Diego County for use as sanitary landfill. Extensive landfill operations have been carried out and several canyons have been filled in completely. Decomposition of waste materials in the landfills has been discovered to be producing significant amounts of methane gas. So much gas is produced that it causes safety and environmental hazards. The Navy has conducted an engineering study of this situation and has determined that the quantity of methane being produced has an achievable energy capacity of 20 MWe and that rate can be expected to last for at least 20 more years. In keeping with the Venture Capital concept, the Navy intends to solicit technical proposals for development of this resource. The structure of the proposals would intentionally be left open to allow proposers maximum latitude in choosing their most economic method of developing the resource. It is expected that proposals would be submitted which entail construction of a collection system for the methane gas and then some form of on-site or off-site use of the gas for cogeneration of some combination of steam or high temperature hot water and electricity. The Navy would select the proposal which provides the maximum economic benefit to the Navy.

NON-MILITARY EXAMPLES

Outside the military services, a number of energy technologies are being utilized or proposed under the Venture Capital concept. In South Carolina and Georgia textile mills are being provided with process hot water provided by solar systems installed and owned by entrepreneurs. In California and Hawaii, large scale windfarms are to be constructed by Venture Capital organizations which will then sell electric power to the utility grid under the provisions of the Public Utility Regulatory Policy Act (PURPA). In College Station, Texas, the Venture Capital concept was even applied to a need for new potable water wells. The State of

California has undertaken a particularly aggressive and innovative approach to Venture Capital Energy Procurement. In June 1982, the State Department of General Services requested initial proposals under a two phase process for development of up to 70 MWe of cogeneration projects and related conservation improvements. The sites for these Venture Capital cogeneration projects are State hospitals, prisons and universities. Individual load sizes range from less than one megwatt to over 30 MWe. The State estimates that by 1990 their facilities energy costs could be reduced by over $700 million by the installation of 400 MWe of Venture Capital cogeneration projects. The first phase of their proposal process elicited considerable interest and the State is now reviewing second phase proposals.

Proposals such as these point to the viability of the Venture Capital concept and each successful project builds a base of knowledge and experience which will support and ease the execution of future projects.

RISKS

The Venture Capital concept is not without risks, both to the entrepreneur and to the government. From the government's perspective, a principal risk is that the requirement for energy which was the basis for a long term contractual commitment might change or disappear. Contract provisions are normally made for such conditions but the government could potentially incur very substantial liabilities if it had to cancel or drastically reduce a contract, particularly in the early years of such a contract. A second risk to the government is the "lost opportunity" risk incurred if a Venture Capital project fails. This is an indirect risk of losing the benefits of some other energy option that was not pursued because of the Venture Capital project.

From the entreprenuer's viewpoint, there is a substantial technology risk. Many of the alternate energy applications being considered under the Venture Capital concept, while not in their infancy, are certainly not at maturity. Under the concept, payment for energy is made only upon delivery thus if the project does not achieve technical success it will certainly not reach financial success.

In concepts involving use of natural resources such as geothermal or coal bed methane as examples, the contractor must also bear an exploration and resource risk. Even when the government provides the contractor with access to a natural resource, such as geothermal energy from government lands, it can not quarantee the specific availability or quantity of that resource. The contract must assign that risk to the contractor and the contract pricing must provide the investors with a return on their investment commensurate with those risks.

A particular risk with potential to cut in either direction is pricing. In order to amortize the substantial investments contemplated under the Venture Capital concept, it is necessary to have long term contracts, from 10 to 30 years. Pricing of the delivered energy commodity over such periods of time is a difficult undertaking. To handle pricing the Navy has created an indexing method which can be used to advance the unit price for delivered energy over time in a fashion that attempts to reflect the contractor's costs of producing energy. For the Navy's geothermal contracts an index called the Coso Geothermal Index was created. This index is composed of four weighted components:

a. The Independent Petroleum Association of America Drilling and Equipping Cost Per Foot Index (IPPA D&E C/F) (weight 40%).

b. The Handy-Whitman Public Utility Electric Light and Power Index (HWPC EL&P) (weight 40%).

c. The Nelson Cost Index, Refinery Construction, Nelson Refinery Inflation Index (NCI NRII) (weight 15%).

d. The Consumer Price Index for all Urban Consumers (CPI-U) (weight 05%).

These cost indices were matched to the cost categories of developing and producing electricity from a geothermal resource. The indices were then weighted to reflect the relative contribution of each index to forecasted costs over the expected life of the venture. Indices are then combined into the Geothermal Index by the following equation:

$$GI = .4(\text{IPAA D\&E C/F})+.4(\text{HWPU EL\&P})+.15(\text{NCI NRII}) +.05(\text{CPI-U})$$

Such an index is only an approximation and an educated guess of how the general economy, the energy economy and the specific economics of a particular energy technology will behave over a relatively long period of time. Navy contracts also contain a provision which caps the price at some specified maximum limit. This limit is usually based on the price of whatever alternative source of energy the Navy would use in absence of the Venture Capital project. Turmoil in the economics of energy over the past few years would suggest that it will be difficult to achieve precision or accuracy from such an index. It may become necessary at some future point to develop new and different pricing methods for further Venture Capital contracts.

ADVANTAGES

As previously indicated, the military services are pursuing the Venture Capital concept because it provides them with significant advantages. In summary these advantages are:

- The avoidance of major capital investments which compete for available capital funds with projects more important and crucial to the military mission.
- The avoidance of the need for provision of personnel and dollars to operate and maintain large complex facilities.
- The avoidance of requirement to be responsible for the management and administration of large and technically complicated plants and systems. This allows management to focus their attention on functions more related to the military mission.
- The avoidance of technological risks while achieving participation in the efficiency and economic benefits of up-to-date technology.
- A participation in the savings achieved by applying major capital investment and modern technology to energy requirements.
- A reduction in energy vulnerability by having access to on-site or nearby energy production facilities.
- The achievement of alternate and/or efficient energy at a pace faster than achievable through the direct Military Construction planning and construction system.

The advantage of the Venture Capital concept to a potential investor or entrepreneur can be simply stated as "...the chance to make money". However, there are a number of facets to the concept that appear to enhance the investor's chances of achieving an appropriate return on investment. Among these are:

- Favorable tax considerations such as Energy Tax Credits, Investment Tax Credits, and accelerated depreciation provided by the government to encourage capital investments and alternate energy development.
- Efficiencies of alternate energy technologies and processes such as cogeneration.
- Favorable conditions relative to the sale of cogenerated power created by the Public Utilities Regulatory Policies Act (PURPA).
- Security provided by a long term commitment from a very stable customer such as the Federal Government.
- Favorable conditions relative to the permitting and approval process when constructing energy production facilities on a government provided site.

CONCLUSIONS

In conclusion, the Venture Capital Energy Procurement concept provides measurable and significant benefits to the Military Services, and to the private investment sector. There are risks involved but experiences to date indicate that these risks can be defined and can be limited or assumed. In the opinion of the author, the Venture Capital concept will become a standard method for the Military Services to conduct their major energy procurements in the future.

INNOVATIVE FINANCING:

WHERE DID IT COME FROM, WHERE IS IT GOING?

DONALD FRAZIER AND DANIEL MILLIRON, P.E.

THE VEGA CORPORATION

INTRODUCTION

Innovative financing, like any business strategy, arose in response to the set of conditions that governed at the moment of its birth. If it is to remain as a viable option in our industry, innovative financing must respond to changes in those conditions.

In the beginning, it was the confluence of rising interest rates, a sagging economy, an aggressive policy of federal and state tax incentives, and rapidly escalating energy prices that brought the investment community and energy users together to establish and promote innovative financing programs for energy conservation projects.

Today, interest rates have fallen and appear to have stabilized. The economy is reviving. Energy tax credits have been reduced or discontinued. Oil prices are falling. Given these changed conditions, it would seem that the time for innovative financing in energy conservation had passed. However, contrary to expectations, innovative financing strategies are increasing in popularity.

The intent of this paper is to identify how innovative financing continues to respond to the needs of the energy user. In particular, we will concentrate on developments in shared savings financing, an innovative financing approach in which outside investors fund energy efficiency projects in buildings owned by others in return for a share in the savings. The future of innovative financing depends on what it offers in relation to the needs of the user.

THE GROWING MARKET FOR INNOVATIVE FINANCING

We observe rising interest in innovative financing in the institutional sector. This group includes state, local and federal governments, school, health care facilities and others who have felt the capital crunch as budgets have been cut and the squeeze in operating funds as costs have risen.

Utilities are interested. Energy conservation is an attractive alternative to costly additions to system capacity. Already, many utilities are actively promoting innovative financing programs among their customers to encourage their participation in energy conservation projects. Several utilities are diversifying and providing investment funds to third party financing programs.

Industry, in general, feels the pressure to improve operating efficiency. During the past ten years, we have seen industry respond more quickly and more effectively to rising energy costs than any other user group. Yet now, as fuel prices soften, projects that improve energy operating efficiency are taking a back seat to more pressing investments in production oriented modifications.

Ironically, the work that has been done by those foresighted, often affluent companies is the impetus for continued conservation efforts in industry. Competing companies whose circumstances earlier forced the postponement of conservation projects now face competition by companies whose operating energy efficiency level is twenty percent or more greater than theirs. Energy conservation equipment will not be removed. That operating performance now becomes the competitive standard for industry to match.

The corporate managements of less efficient operations, both industrial and commercial, face the dilemma of catching up on energy efficiency improvements that were earlier foregone while matching their competitors' investments in other improvements. Shared savings programs enable them to do so. The shared savings approach is particularly attractive in that it produces more value than it costs, and immediately improves cash flow.

Many forces that favor the growth of third party financing programs are at work today. While the conditions that originally supported the development of these programs have changed, shared savings programs are responsive to the new conditions as well. This responsiveness is the key to the future of innovative shared savings programs. An energy [illegible] will undertake a shared savings energy efficiency project if he thinks the opportunity is attractive enough.

ATTRACTIVENESS AND SHARED SAVINGS

What is "attractive enough?" To fully assess the opportunity of shared savings, the owner needs to evaluate the return on his investment. The return includes net cash flow and tax benefits. Standard financial analysis shows return estimates. But there is also some risk involved that, for a number of reasons, savings projections may not materialize.

Thus, in order to evaluate the likely return, the owner must also make assumptions about project performance and take steps to assure high quality performance. His expected net return must reflect the costs of measures taken to enhance the quality and reliability of system performance. He will bear the risk of poor project performance in one way or another, either by taking and paying for actions to reduce and manage the risks or by allowing chance to operate unrestrained.

is choices, the owner will set a quality control management strategy. ill perform well or it won't. It will certainly cost something. The strategy will encompass at least the following generic tasks: 1) facility evaluation; 2) problem identification; 3) solution development; 4) equipment purchase, installation and maintenance; 5) performance monitoring; and 6) performance problem identification and correction.

All these tasks must be performed either by his own staff or by contractors. All these tasks are subject to potential errors. These errors include: 1) judgement errors; 2) mistakes; and 3) performance failures.

Against such errors in these tasks, he directs his quality control management strategy. The key question is how he can insure against errors. Basically, he has three tools: 1) planning; 2) management; and 3) insurance underwriting. Shared savings will be more attractive to the owner if it offers and easier and/or cheaper way to provide a better quality control management strategy.

Therefore, the attractiveness of a shared savings program to an owner is measured by the size and flow rate of net cash flow (and tax benefits) and by the effectiveness, cost and ease (for the owner) of the quality control managment strategy offered by the shared savings program in relation to what the owner would experience in doing the project on his own.

Getting the total picture of these measures is not always easy. There are many variables involved. Omission of a factor can distort the comparison. A basic outline of the decision analysis involved in the comparison and some general rules of thumb are of assistance to the owner in evaluating the attractiveness of shared savings for use in his facility. The next two sections present a brief outline of the analysis and some useful rules of thumb which we have developed from experience.

'S POSSIBLE

We know from experience that most buildings today are consuming approximately twenty percent more energy than is necessary. We also know that a good energy conservation program will pay back its cost in two and one half years or less. These rules of thumb enable us to advise a building owner of the approximate magnitude of energy savings possible in his building and, if we know his current annual energy costs, the investment required to generate those savings.

A simple two and one half year payback on an energy conservation investment that saves twenty percent of current annual energy costs means that the building owner can expect to invest approximately fifty percent of current annual energy costs (2.5 x 20%) to implement the program.

Since actual savings and costs will vary significantly from these numbers, it is necessary for the building owner to commission a comprehensive energy analysis or audit to identify specific energy conservation opportunities and their costs. An energy audit, if it is undertaken by an outside consultant, can vary significantly in price. The price of an energy audit depends on the consultant's standard fee structure, the scope of the analysis, and the complexity of the building and its systems. Fees generally range from five to twenty cents per square foot.

Using these guidelines, the owner of a commercial building whose annual energy bills equal \$200,000 can reasonably expect to save \$40,000 on an investment of \$100,000.

WHOSE MONEY - YOURS OR MINE?

When the potential savings and investment are known, the owner's next question must be: Whose money do I use, yours or mine?

The financial benefits of funding the program in-house are equal to the total cumulative energy savings and tax benefits less the following costs:

(1) The first cost of the installation, including the costs of engineering services

(2) Interest payments (assuming the project is financed through a conventional loan)

(3) Maintenance costs

Under the shared savings program, the building owner is not responsible for any of these costs. They are assumed by the investor in return for a substantial share in the savings and all of the tax benefits of the project.

When the tangible, financial benefits of the shared savings approach exceed those of funding the program in-house, the decision on whose money to use is clear. If, however, the benefits of the shared savings program fall short of those derived from in-house funding, the building owner then evaluates the intangible benefits of the shared savings program before making his final decision. These intangible benefits include:

(1) Risk sharing

Under the shared savings program, the investor shoulders the risk of the savings falling short of engineering projections and the risk of falling energy prices upsetting financial projections.

(2) Project packaging

Shared savings programs provide the owner with a turnkey installation, sparing him the headaches of organizing and managing the engineering and installation.

(3) Performance-based contracts

The shared savings program is a performance-based incentive contract in which the energy services company has a stake in the success of the project.

(4) Maintenance

The equipment installed under the shared savings program must operate at peak efficiency if it is to deliver the savings projected. The energy services company must deliver high quality maintenance to insure that the savings continue to flow at the projected rates.

In addition to these benefits, the shared savings program enables building owners who do not have the funds available, or who would rather employ those funds elsewhere, to implement an energy conservation program and substantially improve cash flow through improved energy efficiency. This final benefit usually weights the analysis in favor of the shared savings approach.

CASH RETURN RULE OF THUMB

The complexity inherent in an energy management project and the relative newness of these projects to an organizational decision process often leads to a distortion of the relative attractiveness. To avoid such distortion and ease the analytic difficulty, we offer a rule of thumb, developed from experience, which can assist owners in deciding whether or not to use shared savings.

This rule is based on a fairly simple model designed only to give a feel for the project comparisons.

If you assume the following:

- o The sharedsavings program runs 7 years.
- o Loans can be obtained at 15% per year.
- o Available capital can be invested by the owner and will return 15% per year.
- o Savings are share 50-50 by owner and investor.
- o Maintenance costs are five percent of installed costs.

- o Fuel and maintenance costs escalate at a rate of 5% per year.
- o A project installation cost of $100,000.
- o Annual savings of 20% on annual bills of $200,000.

Then, shared savings yields the owner approximately 25% or more in benefits than a cash arrangement.

THE SHARED SAVINGS PROGRAM

Shared savings programs are like the proverbial loaves and fishes to the multitude. Third party financing extends and magnifies the capital available to building owners to fund energy conservation projects. Essential to third party financing is the willingness of the energy user to share the wealth buried in operating inefficiencies. His willingness depends on assurances that he can work effectively with the energy services company within a shared savings program.

The benefits of participating in a shared savings program, such as that offered by Vega, are made possible by 1) a participative contract development process, in which user, investor, and energy services company work together to establish the project ground rules; 2) business arrangements that do not lock the participants into the contract before adequate data is on hand but, instead, allow go/no-go decisions at key points during the contract development process; and 3) service delivery systems that utilize performance-based, incentive contracts and integrated, highly specialized teams of engineering, construction, maintenance, management, and financial experts.

Taken together, the contract process, the business arrangements, and the delivery systems insure that the program developed responds to the specific needs and condtions of the energy user and his facility.

The parameters of the shared savings program offered by Vega are developed specifically for each application. The savings sharing rules, contract term, methods for resolving uncertainties, savings calculation procedure, and options to cover contingencies vary according to the needs of each project.

The contract development process is phased to enable the owner to make informed decisions on the basis of hard engineering and financial data. The process further enables the owner to terminate the agreem[illegible] if, in the course of the contract development process, the data pres[illegible]ted suggests an alternate course.

In short, the contract development process opens the "black box" allowing the owner to see inside and adjust the elements to best suit his special needs.

The flexible shared savings contract also protects the investor. As conditions change, the definition of a good investment also changes.

A rigid, off-the-shelf program, marketed without regard to varying interest rates, inflation, and other financial conditions, would quickly be out-moded.

WHAT'S NEXT

The shared savings approach to financing energy conservation, like energy conservation itself, is not an anomaly that is fragile and dependent upon the maintenance of the conditions that prevailed at the time of its first use. The shared savings approach or performance contract is flexible and responsive. It is a relevant option as those conditions change.

The principals of our company were part of the early R&D efforts that led to the development of what today have become the industry standards in legal arrangements and delivery systems. We know that, while the details of these programs will continue to evolve, the approach currently in use will remain essentially the same. The business framework is sound.

Ten years ago, the abrupt spike in the cost of energy exposed gross inefficiency in the consumption of energy by all sectors of our economy. That inefficiency and the unnecessary cost that it masks represents a hidden resource that will not soon be exhausted, even with a drop in oil prices.

Through energy conservation, that resource can be identified and claimed. Innovative financing, whether shared savings, lease, or lease/purchase, is a tool that enables all of us, regardless of our circumstances, to get started and enjoy the long term benefits of lower costs and improved efficiency.

UTILIZING TAX BENEFITS FOR RESOURCE RECOVERY AND OTHER ENERGY PROJECTS

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Tax leasing is a method of financing which dramatically cuts financing costs by transferring tax benefits (generally tax credits and depreciation) associated with the purchase of new plant and equipment.

There are two types of tax leases: the true lease and the safe harbor lease. The latter was a device created by the Economic Recovery Tax Act of 1981 (ERTA) but recently modified by the Tax Equity and Fiscal Responsibility Act of 1982. Table I summarizes the key characteristics of the various tax leasing alternatives.

Safe harbor originally was intended to stimulate investment by allowing tax benefits to be easily transferred. Unfortunately, under the new law, the safe harbor lease is no longer as attractive a financing alternative for a resource recovery plant when compared to the true lease option. Among other things, for most assets the new law delays the taking of tax credits and lengthens the period of time over which the assets can be depreciated. Furthermore, the safe harbor lease is only available for projects that are in commercial operation before January 1, 1984.

The true lease enables a company, agency, or entity who pays little or no taxes, such as a municipality or a capital-intensive, but low-profit manufacturer, to obtain new plant and equipment at a lower cost by passing on the tax benefits to an investor who faces higher taxes. The

TABLE I

	"True" Lease		"Safe Harbor" Lease		
	Leveraged	Single Investor	Tax Benefit Transfer	Financing	"Finance" Lease
Available	Now	Now	Now Thru 1983*	Now Thru 1983	From 1984
[illegible]ented	Yes	Yes	Yes	Yes	Yes
Asset Type	Any New or Used	Any New or Used	Section 38* Property/New	Section 38 Property/New	Section 38 Property New
Typical Rate	8-10% ITC 10-13% non ITC	9-12% ITC 12-14% non ITC	NA	10-12% - ITC 12-14% - non	? ITC ? non ITC
Percentage Equipment Financed	100%	100%	10-20% Non ITC 15-35% ITC	100%	100%
Maximum Term	80% Of Useful Life	80% Of Useful Life	120% Of ADR*	120% Of ADR*	80% Of Useful Life
Purchase Option at Lease Expiry	Fair Market Value	Fair Market Value	$ 1 Or More	$1 or More	More Than 10% Of Original Cost
Parties	Lessor Lender Lessee	Lessor Lessee	Buyer Seller	Lessor Lessee Maybe Lender	Lessor Lessee Maybe Lender
Legal Status	True Lease Lessor-Owner Owner	True Lease Lessor-Owner	Financing Lessee-Owner	Financing Lessee Owner	Financing Lessee-Owner
Accounting	Capitalized or Operating Lease (FASB13)	Capitalized or Operating Lease (FASB13)	Sale Of Tax Benefits	Capitalized Lease	Capitalized Lease
Timing	o On or Before In-Service Day of ITC o Lengthy Negotiations	o On or Before In-Service Day of ITC o Lengthy Negotiations	o Within 90 Days of In-Service Day o Simple Documentation	o Within 90 Days of In-Service Day	o Within 90 Days of In-Service Day
Benefits	o 100% Financing o Possible Off Balance Sheet o Low Finance Rate	o 100% Financing o Possible Off Balance Sheet o Low Finance Rate	o Immediate Earnings o Simple Agreement	o 100% Financing o Low Finance Rate	o 100% Finance o Low Finance Rate

* Section 38 property is tangible personal property including integral parts of manufacturing and production facilities.

* Safe harbor

* ADR is Asset Depreciation Range, a classification of assets by depreciation period.

investor/lessor retains legal ownership of the plant and equipment in order to get the tax benefits while the operator/lessee obtains the ownership advantages minus tax benefits.

The investor/owners who can use the tax benefits create a partnership to borrow money in the cheapest possible form. Depending upon the available tax advantages, 20 to 30 percent of the funds are put up by the investor/owners who then borrow the remainder from third-party lenders.

Tax leasing is primarily a way of reducing the interest rate of a project. In the pricing of a lease one speaks in terms of a discount off the normal debt rate. The discount varies with whatever the tax characteristics of the facility are, but it can be substantial. The implicit interest rate in a true lease transaction with Investment Tax Credit (ITC) and a debt rate of 15 percent, for example, can be discounted to 8 percent.

EXAMPLE - REFUSE FUELS, INC.

Citicorp recently developed a true lease financing structure as partial funding for an $89 million, 1,300 tons per day (TPD) resource recovery facility, Refuse Fuels, Inc. (Haverhill, Massachusetts). The project was funded by the proceeds of an $8 million Urban Development Action Grants (UDAG) loan; $22.8 million in equity financing from SBR Associates, a leasing partnership which includes Citicorp; and $58.2 million from bonds which achieved a Triple A rating, underwritten by Lehman Brothers Kuhn Loeb. The principal and interest on the bonds are guaranteed by municipal bond insurance.

Partners in SBR Associates are Citicorp Omega Lease, Inc. and New England Merchants Leasing Corporation. They are the owners/lessors of the facility and receive the tax benefits and lease (or "rent") payments. Refuse Fuels, Inc. is the operator/lessee of the facility.

The operator's rent obligation is secured by facility revenues, waste disposal and energy sale contracts, insurance, and letters of credit. the contractor is held to fixed-price, performance standards, and a scheduled completion date. In addition, there is a $50 million insurance policy should the facility fail to produce energy up to a specific efficiency level.

In exchange for loaning the UDAG funds, the communities of Haverhill and Lawrence will receive profit sharing from the project.

SOME CONSIDERATIONS FOR PLANNERS

The major advantage to a project, if it is operated by a private, tax-paying entity, is that the tax credit is available to the investor. A city must relinquish some day-to-day influence over the facility's operations to take full advantage of the true lease. This should not be a major problem because the city still has accomplished its objective: to have the assurance that it will be able to dispose of its refuse.

On the other hand, if the city insists on retaining control over the project, it will likely be considered the operator by the Internal Revenue Service (IRS) and thereby eliminate the availability of the tax credit. If the tax credit is not available, the investor receives less tax benefits (only depreciation and interest deductions) and, therefore, must receive a higher rent to give him the same return on his investment.

The question involving eventual plant ownership arises at the conclusion of any true lease. Although the facility will have seen its most productive years, its value at lease expiry could be considerable when the inflation rate over the period is considered. The true lease requires an option to purchase the facility at its then fair market value.

When deciding on a true lease, the operator must be satisfied that the future value of the amount saved by making lower rental payments, versus the alternative debt payments, more than covers the expected value of the plant at the expiration of the lease. However, under the new law, projects financed after December 31, 1983 may qualify to be funded by a "finance lease" which allows fixed price purchase options (see Table I).

If a municipality insists upon being the operator and the tax credit is lost, the future value of the savings frequently equals double or triple the initial cost of the asset. Therefore, unless it can be accurately projected that a $100 million plant will be worth $200 million to $300 million in twenty-five years, it would be prudent to lease the facility even in the case where the municipality wants to operate the plant. Under a true lease the owner retains the upside potential of the facility's future value.

Both real estate costs and the construction period qualify for financing under a true lease structure, and rapid depreciation-known as "Accelerated Cost Recovery System" in IRS terminology-is available. Also the initial term of the lease can extend up to 80 percent of the project's useful life. Thereafter, the lease may be renewed indefinitely.

LAY OFF RISKS

The creditworthiness of any project is contingent upon several conditions: the availability of waste, the technology utilized, the energy revenues derived from the project, and the likelihood that construction will proceed smoothly.

Time is the project's worst enemy. The cost of a project can double while consultant studies accumulate. To reduce funding costs, it is necessary to make use of all available financing sources. Although it takes time to put such a deal together, the so-called complexities of leasing do not meaningfully extend the time because the concepts are simple.

The actual leasing documentation involves a small part of the total effort. Establishing a sound credit structure is the major challenge. Guarding against the risks associated with waste supply, plant technology, and prevailing energy market should be focused on by all participants in a project financing.

An experienced financial team, chosen early in the process can provide advice on how to structure the transaction to avoid expensive and time-consuming backtracking.
Tax leasing is a tool which can meaningfully enhance the viability of a resource recovery project.

APPLICATIONS OF MINICOMPUTERS TO ENERGY PURCHASING

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I. INTRODUCTION

Tracking and controlling energy costs are important corporate functions, especially during depressed economic times, and imperative to a company such as Air Products and Chemicals, Inc., where energy costs consume twenty-one cents out of every sales dollar. Furthermore, energy costs account for as much as seventy-five to eighty-five percent of the variable operating costs at many Air Products locations. This tremendously energy-intensive nature of Air Products' business entails that energy costs be monitored and forecasted; these tasks are two of the main functions of Air Products' Corporate Energy Department.

This morning I would like to present some of the minicomputer applications that Air Products' Energy Department has developed in order to improve our energy management program. The three main applications I will discuss today are energy price forecasting, plant energy usage and cost monitoring, and energy investment analysis. The type of software chosen to implement each of these applications will be discussed, along with other problems and considerations incurred during the development of these applications. Finally, I will discuss our next minicomputer application which is currently in development.

The decision to use a minicomputer for energy purchasing applications was a natural one; the vast amount of data to be collected and stored, the repetitious nature of the calculations, and the need for sensitivity studies indicated that a computer was needed, but a time-sharing mainframe computer was ruled out because of the initial cost to implement the system and the cost of on-line data storage. Hence, a minicomputer was the answer. The applications I describe today are performed on an Apple II plus, but they could easily be developed for another minicomputer system.

II. FORECASTING

Forecasting energy costs is a vital function of Air Products' Energy Department. The economic feasibility of many capital investment projects often depends on the projected energy costs associated with the projects. Furthermore, because of its extreme energy-intensiveness, once a decision to build a new plant in a given marketing region has been made, forecasts are necessary to identify the lowest cost electric utility or natural gas pipeline in the region over the lifetime of the plant.

Air Products' Energy Department has developed three detailed forecasting models: an electricity supply and price forecasting model, a natural gas pipeline pricing model, and a crude oil market forecasting model. All three of these models are written in the Pascal programming language and have been developed in-house. In the interest of saving time, I will only explain the methodology of the electricity forecasting model in order to illustrate the capabilities of a minicomputer when coupled with user-written software.

The methodology of the electricity forecasting model is relatively straightforward (see Figure 1). There are three major cost components which together determine the average system cost of generating electricity to a utility. These cost components are namely Fuel Cost, Capital Cost, and Operation and Maintenance Cost. Each of these cost components are modeled separately in subroutines.

ELECTRICITY FORECASTING METHODOLOGY

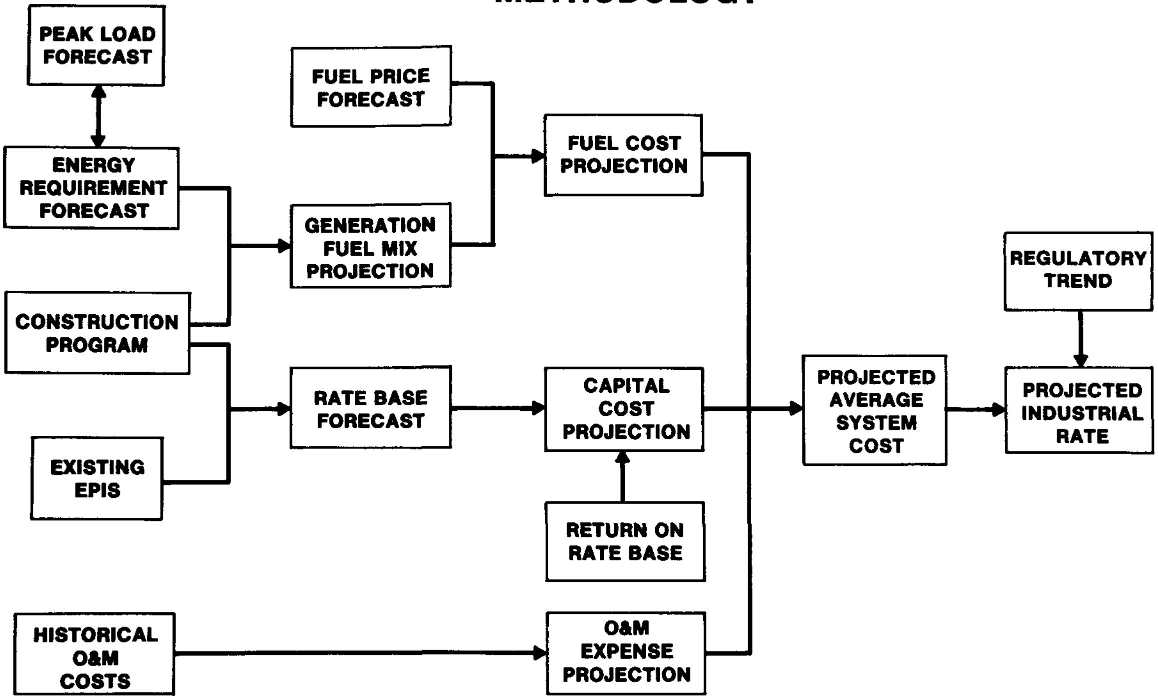

FIGURE 1

The Fuel Cost subroutine begins by obtaining an energy generation requirement forecast, which is either input or calculated from a peak demand forecast via the system load factor. The combination of the existing generating facilities and the construction program determines the maximum available energy that could be produced by each fuel type of generating unit. The computer model then applies a built-in economic dispatch routine to project the generation fuel mix, including purchased power, based on the fuel price forecast, with the lowest cost fuel being utilized to capacity first, and so on, until the energy requirement has been met. The total fuel expense is then divided by the projected energy sales (in kilowatthours) to calculate the per unit fuel cost.

The Capital Cost subroutine begins with the electric utility's planned generating unit construction program as an input. The carrying cost of capacity additions, including transmission and distribution facilities, is then determined from the required rates of return on new capital investment, which typically consists of 50% debt, 40% common equity, and 10% preferred stocks. The carrying cost of the existing generating facilities is similarly calculated, except that the embedded interest rates of the old debts are used. These two carrying expenses plus allowances for depreciation and tax expenses are then summed and divided by the projected kilowatthour sales to determine the per unit Capital Cost.

The Operation and Maintenance Cost is calculated quite simply. The total operation and maintenance expense from the base year is divided by the base year kilowatthour sales to obtain the per unit cost then escalated at the general rate of inflation to determine future O&M.

Once the average system cost has been obtained, the regulatory environment under which the utility operates must be taken into account in order to project an industrial rate. Depending upon the local regulatory trend, a specific cost allocation method may be adopted by a local regulatory commission to favor certain classes of electricity customers. The translation from the average system cost to an industrial rate is the most subjective part of the forecast and must be based on years of experience and contact with public utility commissioners and electricity ratemaking issues. The electricity forecasting model can easily be run repeatedly to test the sensitivity of the average industrial cost to basic underlying assumptions, such as the inflation rate, interest rates, and economic growth rates.

The complexity of the forecasting model dictated that a computer program be developed in-house using a high level programming language. Pascal was chosen as the programming language because it is well suited for file manipulation and data input and output. The natural gas and crude oil forecasting programs also use sophisticated sorting and statistical analysis subroutines that were not readily available in other programming languages. Pascal does, however, have two drawbacks: the language is not generally well known and there are not many vendor-supplied software packages written in Pascal. Fortunately, these two disadvantages are rapidly disappearing.

A more simplified method of forecasting electricity costs is shown in Figure 2 using a software package called Visicalc, which is written by Personal Software, Inc. Visicalc is best described as an electronic worksheet; formulas can be written to perform simple calculations on rows or columns and create another row or column. Figure 2 shows a forecast of a hypothetical electric utility; the main purpose of this figure is to illustrate the capabilities of Visicalc. The utility's total system peak demand and energy requirements are input at the left side of the electronic sheet. The Visicalc program than dispatches the generating units as needed until the system load is met. At the extreme right side of the electronic sheet, the individual generating unit outputs and costs are summed, and finally, an annual unit cost is calculated. The program can be designed so that only the year of the forecast needs to be entered at the top of the electronic sheet; the system load and individual generating unit costs will automatically be escalated at a given rate and the dispatch proceeds to calculate the annual unit cost. This method of forecasting is grossly simplified compared to the previous method; it can only be used for utilities which primarily only buy and resell electricity or own only a few generating units (e.g. municipal or cooperative utilities). In general, certain costs, such as operation and maintenance costs, taxes, and transmission and distribution costs cannot be identified with, or assigned to, particular generating units. In this case, the previous method of forecasting must be used.

VISICALC EXAMPLE
UTILITY XYZ
MARCH 1983
FORECAST FOR YEAR 1985

	TOTAL SYSTEM		UNIT #1			UNIT #2					
	DEMAND	ENERGY							TOTAL GENERATION		
MONTH	KW	MWH	KW	MWH	COST	KW	MWH	COST	KW	MWH	COST
APR											
MAY											
JUN											
JUL											
AUG											
SEP											
SUM TOT											
OCT											
NOV											
DEC											
JAN											
FEB											
MAR											
WIN TOT											
							YEARLY TOTAL				

FIGURE 2

III. PLANT ENERGY USAGE AND COST MONITORING

Air Products operates over 100 air separation facilities located at more than 65 different locations in the U.S. alone. During fiscal year 1982, energy costs totaled more than $300 million. The tracking and analysis of the energy usage and costs at all these locations would be next to impossible without being computerized.

Figure 3 is an example of how Air Products' monitors the usage and cost of electricity at our major LOX/LIN facilities. For each location the electricity supplier, the monthly electricity demand and energy usage, and the corresponding demand and energy charges are provided. The data is taken directly from the utility's monthly billing. This electricity data tracking is done for two reasons: (1) as the data is entered, the utility's billing is checked for accuracy, and (2) once entered, historical data can be collated and analyzed. A similar tracking procedure is followed for our natural gas consumption at various locations.

These energy costs are collected and analyzed by a software package called Data Base Master (or simply DB Master), which is written by Stoneware Microcomputer Products. A wide variety of analyses can be performed on the data by using DB Master: reports can be generated with any of the columns from the table eliminated, formulas can be written to perform simple calculations on the data, or the data can be sorted on any column. Some very useful applications of these options are to: (1) compile the historical data of a particular plant location, (2) arrange the plants in increasing order of electricity cost (3) determine a year-to-date electricity cost at each plant, or (4) calculate each plant's load factor to examine its performance. Furthermore, data can be transferred to another vendor software package called Visitrend + Visiplot, written by Personal Software, Inc., which provides powerful graphics capability. These two software packages, of course, do not have to be used exclusively for energy purchasing applications; other applications can help justify the cost of purchasing the software.

DB MASTER EXAMPLE

ELECTRIC COSTS AT MAJOR LOX/LIN FACILITIES

MARCH 1983

					DEMAND CHARGES					VARIABLE CHARGES								
FACILITY	UTILITY	INTER. DEMAND (XW/KVA)	BILLING DEMAND (XW/KVA)	USAGE (KWH)	DEMAND CHARGE	REACTIVE	CUSTOMER AND/OR FACILITY	VOLTAGE/ DEMAND DISCOUNT	TOTAL FIXED CHARGES	ENERGY CHARGE	FUEL CHARGE	TAXES	MISC. CHARGES	TOTAL VARIABLE CHARGES	TOTAL MONTHLY BILL	DEMAND CHARGE (CT/KWH)	VARIABLE CHARGE (CT/KWH)	TOTAL AVERAGE (CT/KWH)

FIGURE 3

IV. ENERGY INVESTMENT ANALYSIS

During the past two years, Air Products' Energy Department has been evaluating the feasibility of an increasing number of conservation and cogeneration projects, creating the need for a computerized method of analyzing these projects. A fairly simple program was written in BASIC to aid in the analysis of these capital investment projects. The program requires the following input data: the initial amount of capital investment, the real cost of capital, the future revenue and expense stream, and the annual inflation rate. Several options are provided to account for income taxes, investment tax credits, and various methods of depreciation. The program calculates gross income, depreciation expense, income before taxes, income taxes and net income for each year of the project and determines the internal rate of return and the payback period of the investment. The analysis of various capital investment projects is expedited and improved through the use of the computer program, which helps to make the decision process more efficient.

V. THE NEXT STEP

A word of caution must be mentioned at this point: All vendor-written software packages and user-written programs as well as minicomputers themselves have limitations to their capabilities. One of the most important considerations to keep in mind when one begins to computerize an energy purchasing task is to predict what one's long-term computer needs might be. For instance, in monitoring plant energy usage and cost, one must remember that over time more and more data must be stored; the memory limitations of the software package and the minicomputer must be examined to determine if a problem will arise in the future. If this examination indicates that a problem may arise, either the task should be revised, or a minicomputer or software package with larger capabilities should be used from the beginning.

Another problem is that the type of analysis one wants to perform on data may change or expand over time. Often a software package may not be capable of performing these other analyses. (This is one advantage of user-written programs, the program can be modified to allow the additional analyses.) Another software package may possess the capabilities which are needed, but this may require re-entering all of the data. This problem has been experienced at Air Products; we wanted to use a software package to analyze data which already existed in another package, but the two packages were not compatible. It was impractical to re-enter all the data, so the idea was temporarily dropped.

Steps are being made, however, to make software packages more compatible with each other, at least to the point where data can be exchanged between the two programs. Software Arts, Inc. has developed a standard language called Data Interchange Format (DIF) in order to allow programs to communicate with each other; with modifications, many software packages and user-written programs can exchange data. Air Products' Energy Department is presently working on methods that will allow each of our minicomputer applications to access data from any other application through DIF. For example, the results of the electricity forecasting model (which is written in Pascal) will be passed via a DIF file to Visitrend + Visiplot and graphically displayed. When completed, this feature will greatly enhance the overall capabilities of our computer applications.

VI. CONCLUSION

I believe that the few examples of minicomputer applications which I have shown to you today illustrate the tremendous usefulness and versatility of minicomputers; both the quality and quantity of work of an energy management department can be increased significantly. The ever-increasing demands placed on energy purchasing departments should be alleviated through the increased utilization of minicomputers and associated software.

Part III

USING ENERGY EFFECTIVELY

Although some energy prices are declining a bit, overall energy prices are still historically very high.

In response to increasing real energy prices, new technologies, processes and management schemes have been developed to increase energy efficiency and thus control total energy cost. Although significant progress has been made in improving energy efficiency, much remains to be done even after real energy prices stabilize.

This section describes a number of case histories of the use of technologies and practices that have been effective in significantly improving energy productivity. Together they improve the basis for even greater energy productivity gains in the future.

FINANCING ENERGY CONSERVATION PROJECTS THROUGH SHARED SAVINGS

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President
Time Energy Systems, Inc.

Shared savings is an increasingly popular way of financing energy conservation projects. Shared savings financing is an arrangement in which an energy efficiency system is installed and maintained in a user's building with no initial charge to the user. Financing comes from the energy services company. In return for its investment in the design, equipment, installation and maintenance of the system, the energy services company receives all of the tax benefits (usually) as well as a percentage of the savings generated by the system for a predetermined period of time. Contracts range from seven to 12 years, with the savings split running from 40 to 80 percent, in favor of the energy services company. The length of the contract and the savings split are determined by economic feasibility, payback and risk. The energy services company itself finances the system through either internal means, investment banking firms, or third party investors.

The reason for the increasing popularity of shared savings financing has to do with an increased understanding of this type of financing due to a number of studies on the subject conducted by numerous organizations. In his pioneering study of shared savings financing, Richard Esteves, Conservation Manager of General Public Utilities (GPU) of New Jersey and Pennsylvania, has observed that "from a strictly economic standpoint, shared savings programs are normally the best alternative for financing energy conservation in non-profit buildings."[1] But other studies indicate that shared savings financing is a viable alternative for profit-directed companies as well. The Alliance to Save Energy has advocated shared savings financing for energy efficient industrial projects.[2] Martin Klepper, in a study sponsored by the Department of Defense, concludes that shared savings is a desirable method of financing energy conservation projects for any profit-making company.[3] Among other studies that also support the shared savings concept are ones sponsored by the American Hospital Association, Logistics Management Institute, Blue Cross/Blue Shield, the National Community Energy Management Center, and the Energy Law Institute. (See bibliography at the end of this article.)

Although the obvious advantage in shared savings financing from customer's standpoint is obtaining an energy conservation system without having to make a capital investment, shared savings financing has other advantages. One is that since the customer's capital is not being tied up in an energy conservation system, it can be used for upgrading manufacturing equipment, expanding the building or facilities, or investing in research and development projects. In other words, shared savings financing allows the customer to "have his cake and eat it too." This theory is supported in an article in the November/December issue of Energy Management magazine entitled "Comparing Financial Alternatives in Tough Times."[4] In this article, the authors compare the financing of an energy efficiency system through shared savings versus all cash or a combination of debt and equity, using a variety of internal discount rates. Their conclusions quoted below, are documented by computer models showing the present value of shared savings and presented in Figures 1 through 4, found at the end of this article.

> "Even if a user has all the necessary cash currently available, use of a shared savings plan for at least some conservation projects may actually yield a larger stream of present value benefits than if the user had financed the project himself.
>
> ". . . if the user's discount rate is higher than the internal rate of return he would expect from financing the project on his own, it makes little sense to invest his own cash in such a project. Yet, a third-party investor may be willing to finance the same project under a shared savings plan. Since the user has put up none of his own cash, the present value using his discount rate is higher under the shared savings plan than if he had used his own cash. Other factors which contribute to this result are the fact that the user achieves an immediate positive cash flow under the shared savings plan, whereas under cash or debt financing, the cash flow does not become positive for a year or more.
>
> "Finally, the value of the shared savings option is increased because the cash which would have been utilized to finance the project is available for alternative investments."

Figure 1 assumes that the user's available cash is placed in an alternative investment opportunity with a similar degree of risk which yields returns equal to his discount rate. The user with a 30 percent discount rate who has cash available now would still be ahead by utilizing a shared savings plan even for an investment with a payback as low as 9.5 months.

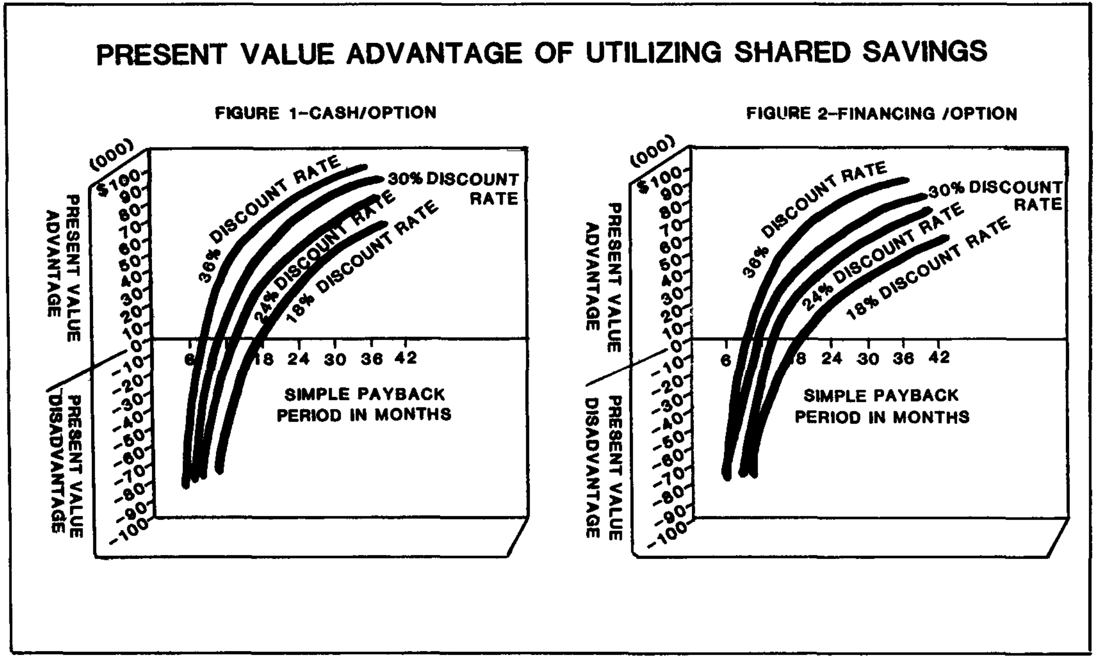

Fig. 1 shows the present value of doing energy conservation projects through shared savings and alternative proje[illegible] with current available cash, usi[illegible]ious discount rates.

Fig. 2 shows the present value of doing energy conservation projects through shared savings and alternative projects with cash available through financing, using various discount rat[illegible]

Figure 2 makes a comparable analysis which compares the present value benefits of utilizing a shared savings plan against a combination of debt and equity, assuming both necessary cash and debt financing are currently available. This figure also assumes that only 20% cash downpayment is available for alternative investment at the user's discount rate. As Figure 2 illustrates, use of the shared savings option produces superior results over a surprisingly wide range of discount rates and projected paybacks. The user can "eat his cake and have it, too."

> To quote the article further,
> "The real choice confronting many energy users, however, is whether to sign a shared savings plan today or wait anywhere from six months to two and one-half years to obtain the necessary capital and/or debt financing for his own investment."

Figures 3 and 4 are based on a break-even analysis which is designed to answer the question: How long can an energy user wait for either internal cash and/or financing and still come out as well on a given energy project as he would if he signs a shared savings agreement for the same project today? The answer varies with his internal rate of return. With an internal rate of 24 percent, the user is better off signing a shared savings contract today for a project with an 18-month payback unless he will have sufficient cash within eight months to fund his own project. (See Figure 3.) If a combination of debt and equity is contemplated, a user with a 30 percent discount and a project with an 18-month payback would need to obtain the necessary financing within 11 months in order to beat the present value advantages of a shared savings plan.

The above conclusions have to do with companies that have the necessary cash or can obtain financing for energy conservation projects. Obviously, those that do not have the cash or financing opportunities can immediately benefit from the cost-avoidance factor of a shared savings program for energy conservation projects. Many state governments are beginning to realize the validity of this statement, as is the federal government. In the past state and federal agencies were not allowed to sign multi-term contracts, thus eliminating the possibility of using shared savings financing for energy conservation projects. In the past year, however, many states have passed legislation allowing their agencies to sign multi-term contracts, specifically for the purpose of obtaining shared savings financing. In addition, the Department of Defense and the General Services Administration are both sponsoring pilot projects to test the results of a shared savings program. With such state and federal support, the government may become the most eager proponent of shared savings financing.

There are other reasons for a company to opt for shared savings financing of an energy conservation project, even if the company might come out ahead by using its own resources. One reason is technological risk.

> "If a user is not convinced that a particular technology will deliver the projected savings, he can transfer the technical risk to the energy services company. If the technology fails to produce the savings, he owes nothing."[4]

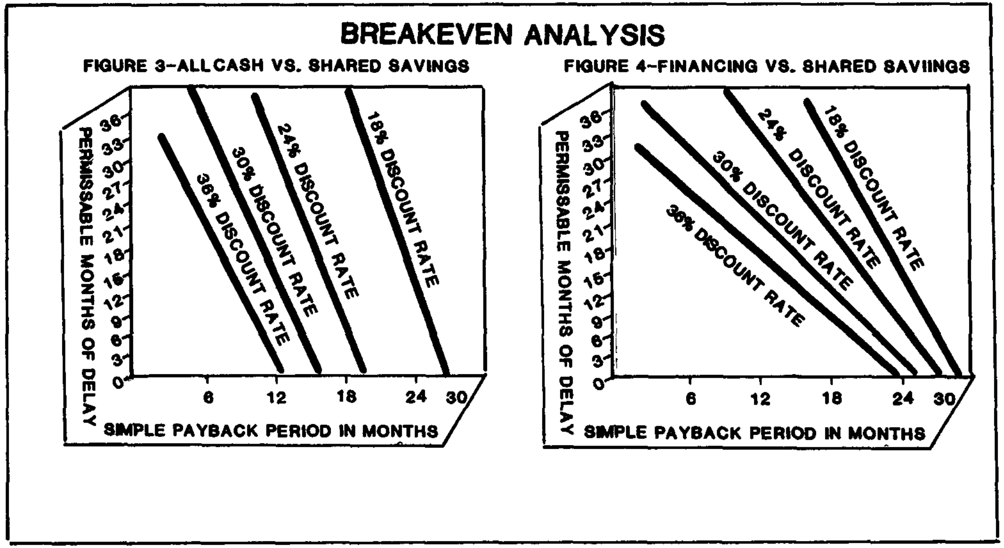

Fig. 3 shows the number of months the user can afford to wait for capital to finance a given project and still receive the same present value benefits as would be obtained from a shared savings plan signed currently.

Fig. 4 shows the number of months the user can afford to wait for financing to undertake a given project and still receive the same present value benefits as would be obtained from a shared savings plan signed currently.

The energy services company, which designed, installed and maintains the system using its own funds, will bear the brunt of any technical failure. But because it has a profit motive in the success of the system, the energy services company is strongly inclined to install the best system in the customer's facility and use its best efforts to maintain the system and maximize the savings.

Another reason for opting for shared savings financing -- if the r is planning to obtain financing for the energy conservation pro- -- is that shared savings financing will provide "off-credit, off ance sheet" financing, which may be desirable for the user's financial statements.

Finally, there is the competitive advantage. By utilizing a shared savings program now, rather than waiting until debt or equity capital becomes available, the user can immediately reduce his operating costs and perhaps gain a competitive edge, especially where operating margins are slim and vulnerable.

With such a wide range of benefits, shared savings financing appeals to a variety of companies. Projects financed through shared savings include Fortune 500 companies, national chains, and major industries, in addition to hotels, banks, office buildings, hospitals and health care centers. And, with the support of state and federal governments, public buildings, high schools, colleges and universities are beginning to open their doors to shared savings. Even public utilities are getting into the act.

With increased demand that generates the need for new power plants, public utilities are espousing shared savings plans for their customers. General Public Utilities of New Jersey and Pennsylvania last year sponsored a series of shared savings seminars for their customers. Pennsylvania Power & Light sponsored an exposition in which speeches on shared savings played a major role. Bonneville Power & Lighting in the Pacific Northwest is sponsoring a test project for shared savings of energy conservation projects, and other power companies are involved directly or indirectly through joint ventures in shared savings projects.

HOW SHARED SAVINGS WORKS

A shared savings project begins with an initial audit of the customer's facility to determine how energy is used and where it might be saved. The customer's past energy usage is analyzed and a "base year" ablished. The base year is an average of fuel consumption for each h of the past three years, stated in fuel units (KWH or CFG). ustments are made where necessary for unusual weather conditions and changes in occupancy or energy requirements. Once mutually agreed to by the energy services company and the customer, the base year becomes part of the shared savings contract.

Savings are measured by comparing current energy usage with usage before the system was installed, as established by the base year. The utility company's current billing structure is entered into the computers of the energy service company, and each month a simulated bill is prepared for the corresponding month of the base year (calculated at current rates) and compared to the customer's current bill. The actual savings is the difference between the current bill and the simulated bill of the base year:

SAVINGS = (CORRESPONDING MONTH OF BASE YEAR X CURRENT RATE) - CURRENT BILL

The energy services company then bills the customer for the percentage of savings stated in the contract.

THE SHARED SAVINGS CONTRACT

The percentage of savings paid by the customer is only one aspect of the shared savings contract. In general, the contract establishes obligations of both parties over the life of the contract. Standard information that should be in the contract includes the . . .

- type of equipment to be installed;
- location of the user's facility;
- percentage of savings split between the user and the energy services company;
- terms of payment of bills;
- length of the contract; and
- a mutually agreed upon base year formula for each building under contract.

The contract should also establish a right to termination of the contract, usually necessary only when minimum savings have not been achieved during a previous 12-month period. There should also be a provision for remedies in case of a breach of contract by either party, but the provision should be stated in such a way that the entire contract would not be undermined if only one monthly payment were missed.

HOW TO SELECT AN ENERGY SERVICES COMPANY FOR SHARED SAVINGS FINANCING

Although the structure of the contract is important in selecting an energy services company, three considerations should govern the choice: engineering expertise, customized design, and references.

- Engineering expertise. The energy services company must be a credible engineering firm since engineering affects the initial analysis and evaluation of controlled loads during the energy audit, determination of control strategies, design of the system, installation, service and maintenance, and system performance (maximization of savings).

- Customized design. An energy services company should design a system for the customer's needs, rather than trying to make a particular system fit a building. The design of the system includes the selection of the basic controller (from the many on the market), as well as the implementation of various control strategies, such as heating, ventilation and air conditioning (HVAC) controls, lighting controls, waste heat recovery, chiller or boiler optimizers, process control, power factor correction, and so on. How well these strategies work depends on the software for the controller, as well as the controller itself. Of course, all strategies for a custom-designed system take into consideration the needs of the facility, its operating hours, its use of and need for energy, and its occupants.

- References. The energy services company should be able to provide a significant number of references from customers satisfied with all facets of the contract -- from the initial audit through installation, maintenance, and performance. In particular, references should be obtained on the customer's satisfaction with shared savings billing procedures. Experience counts here. The energy services company should have the ability to handle billing structures of all necessary power companies (and they all differ) in order to properly calculate the savings.

In summary, shared savings, when properly used, can represent an attractive means of financing energy conservation projects for a wide range of facilities.

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UTILITY FINANCING OF ENERGY MANAGEMENT:
THE PUGET SOUND POWER AND LIGHT EXPERIENCE

G. W. Lehenbauer

Puget Sound Power and Light Company

OVERVIEW

Puget Power is the largest investor-owned electric utility in the State of Washington, serving approximately 570,000 customers spread out over nine counties and 4,500 square miles. Over 75 percent of the Company's total energy requirements come from hydroelectric sources, with the balance coming from thermal sources, principally coal-generated.

Since 1979, Puget Power has offered its commercial customers an energy management program with two methods for financing cost-effective electrical energy saving improvements for facilities. The first alternative is a cash grant where Puget Power pays approximately 70 percent of the intital energy-saving improvement costs. The second is a no-interest 10-year, deferred payment loan with early repayment incentives.

This energy management program is available to facility owners receiving electrical service from Puget Power. In addition, tenants of commercial facilities may qualify for some measures under the cash grant program with the owner's consent.

Cost-effectiveness is a function of the difference between Puget Power's marginal costs for new base-load generation and current average rates. At the present, this translates into 3 cents per kilowatt-hour. In other words, Puget can invest in energy efficiency improvements that cost up to 3 cents per kilowatt-hour over the life of the retrofit measure. The following measures are typically evaluated for financing:

- Heating and/or cooling systems
- Indoor and outdoor lighting
- Insulation
- Double pane glass
- Process equipment and systems

Due to the popularity of this program, we have done no direct advertising and customer applications are taken on a first come first serve basis. The backlog time to start the process with the customer, averages between four and eight months.

GENERAL PROCEDURES

Once the customer's turn comes up, here's what happens:

Step 1: A Puget Power energy management engineer visits the facility and performs an on-site energy audit. The audit will help establish a correlation between the current operational methods and the electricity billing history. It will also identify conservation measures that may be cost-effective for the facility.

Step 2: The information gathered during the audit will be analyzed to determine possible energy and cost savings. For most facilities, a computer program is utilized to perform the analysis and evaluate the various retrofit options. When the analysis is complete, a financial proposal describing the savings for each improvement is prepared.

Step 3: Upon customer acceptance of the analysis, bid performance criteria will be prepared and bid design proposals will be solicited from contractors. Puget Power's engineers will help the customer select the best bid from both a cost and energy savings viewpoint. A list of contractors interested in participating in the program is provided to the customer. In all cases, the customer has the option of adding or deleting interested contractors from this list.

Step 4: Contractor(s) will perform the work within 30 to 60 days.

Step 5: Puget Power will verify the installation of the conservation measures. If the work has not been completed satisfactorily to meet the bid design proposal, the customer and contractor will be notified.

Step 6: Puget Power will issue payment to the customer upon successful completion of the modifications. The customer, in turn, makes payment in full to the contractor(s). Puget, subsequently monitors the energy savings for up to ten years.

There is no charge to the customer for Puget Power's energy management services. The only charge the customer is obligated to pay is the amount in excess of the 70 percent grant or any amount exceeding Puget's upper financing limits. Puget never pays more than the actual cost of the measures.

PROGRAM EXPANSION

In an effort to decrease the backlog of customer requests without continual staff increases, we have developed optional procedures and guidelines for certain facilities.

Customers may submit "contractor-initiated" proposals for outdoor lighting improvements without taking the formal program steps outlined above. These may be single source bid design proposals that can receive approval for financing within one week. This work is typically performed by electrical contractors who may have previously done other satisfactory work for the customer. We are also implementing a pilot program in which we are reviewing some "contractor-initiated" proposals for other than outdoor lighting improvements. In all cases, Puget will provide construction verification prior to payment.

Abbreviated procedures are being developed that will allow us to more quickly respond to 'small' commercial customers. This group basically consists of those customers that use less than 60,000 kilowatt-hours per year, making up more than 70 percent of our 60,000 commercial customers.

To supplement our own staff of energy engineers, we have commissioned a number of engineering firms to perform audits and analyses. These consultants use our analyses methodologies and presentation format. In all cases, we maintain primary communications with the customer. This process has also proven successful where certain expertise, that is only available in the engineering community, may by required.

PROGRAM RESULTS

Projected energy savings will exceed 45,000 megawatt-hours for the 300 projects completed. This will be enough energy to serve approximately 3,100 average residential households. Savings per customer range between 25 and 30 percent.

ECONOMICS

The primary reasons Puget Power is implementing energy management programs is to 'avoid long-term energy shortages' and because it makes 'good economic sense.' In addition, energy management programs have been well received by customers and the utilities commission.

Figure 1 shows the way utilities have traditionally operated and shows what utilities call "declining marginal costs." The curved line shows that the more electricity we sold in the past the lower the cost. This was made possible through technological improvements in the efficiency of generating plants and economies of scale that made each plant cheaper, per unit of output, than its predecessor.

Beginning in the 70's and continuing into the 80's, we have been seeing a situation that involves "increasing marginal costs" as shown in Figure 2. We are beginning to shift in increased reliance on much more expensive thermal power plants. This is especially apparent in our case as we have nearly exhausted the capabilities of our hydro base. Now, therefore, the more electricity we sell, the greater the generation cost.

Rates are typically based on the average cost of energy. If we add a small block of very expensive thermal plant, we still get a fairly low average rate. But, as shown in Figure 2 at Point A at the "margin," we are losing money for that new block of very expensive thermal plant. Utility regulation continues to only allow rates that reflect the 'average' cost of energy and we never quite catch up to recover these losses.

As the cost of capital and fuel goes up more and more utilities are getting into a position of losing money at the margin. It may then become profitable for the utility if their customers begin "using less of their only product." In fact, it may now make sense for utilities to pay customers, up to the amount being lost at the margin, to use less energy. These basic economics have been applied by Puget in developing the levels of incentives for energy management programs.

Figure 1 - Decreasing Marginal Costs

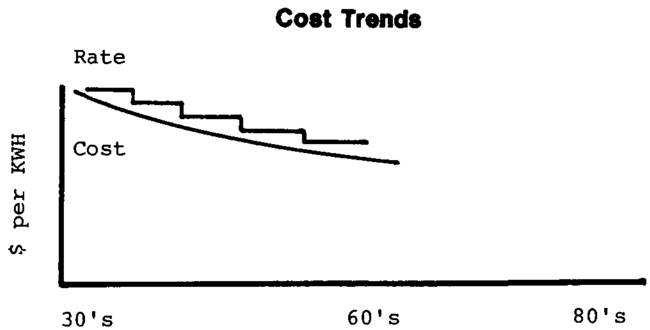
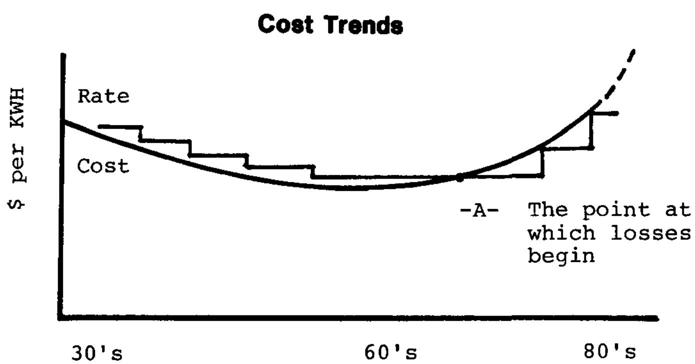


Figure 2 - The Effect of Increasing Marginal Costs



CASE HISTORIES

The following case histories, although a little more complex than the average job, are representative of many of the projects on this program.

Case History #1

Facility Background:

A two-story 60,000 sq. ft. office and light manufacturing facility is a current participant in the commercial energy management program. The structure was built in three parts over a ten-year period and features an 1,800 sq. ft. central atrium, open to both floors, which provides a pleasant working environment for 350 employees. Their main product line consists of printed circuit board switching equipment for the communications industry.

Heating and cooling is provided by 30 package rooftop units. Each unit has electric resistance heating and direct expansion cooling capability, and sizes range from 1-ton to 25-tons. Two additional units are 1-ton heat pumps.

Exterior walls are constructed primarily of concrete block, insulated with one inch of foam. There are 2,670 sq. ft. of single pane windows which make up about 14 percent of the total wall area. Double glazing and additional insulation were determined not to be cost-effective due to substantial internal base load heat gains. Major base loads are people, lighting office equipment, and electronic test benches. Light machinery, hot water, and small computers also contribute a significant proportion.

The facility's average monthly electricity bill was $5,200 for 240,000 kilowatt-hours in 1980. Specific energy usage was 48 kilowatt-hours/sq. ft./yr. before modifications, and is now about 32 kilowatt-hours/sq. ft./yr. Demand ranged between 500 and 700 kilowatts with a winter peak and monthly average of 570 kilowatts.

Conservation measures included modification of heating and cooling equipment and controls plus changes in interior and exterior lighting systems.

Night, or unoccupied period, temperature setback in the heated space normally has a short payback and is often the first conservation measure to be considered. Each heating/cooling unit was retrofitted with a programmable thermostat which automatically controls day (occupied) and night (unoccupied) temperatures in the building. These thermostats also have the capability to predict the optimum time to start equipment in the morning in order to have comfortable temperatures established when employees arrive. Annual savings from this measure amounted to about 90,000 kilowatt-hours or 3 percent. Due to some shift and weekend work in various portions of the facility, the temperature setback savings opportunity was not as significant as it might otherwise have been. A more typical savings range for this measure is 10-20 percent.

Economizer cooling equipment and controls were also installed on the space conditioning systems. Economizers allow modulation of outside air intake and return air exhaust on signals from the room thermostat. This equipment continuously optimizes the proper amounts of outside and return air resulting in energy savings during both the heating and cooling seasons. Due to unusually large amounts of outside air being drawn into the building through fixed dampers before the retrofit, substantial savings during the heating season were achieved. The economizers and controls provide up to 100 percent outside air for cooling, minimum (ventilation) outside air in the heating mode, and no outside air when the building is unoccupied.

Interior lighting modifications included the replacement of over 3,000 40-watt fluorescent lamps with 34-watt energy saving lamps. A number of incandescent fixtures were also relamped with reduced wattage bulbs.

Ten pole-mounted 1000-watt mercury vapor parking lot luminaires were replaced with 200-watt high pressure sodium luminaries. Similarly, ten post-mounted 175-watt mercury vapor driveway fixtures were retrofitted with new 70-watt high pressure sodium lamps and ballasts saving a total of 44,000 kilowatt-hours per year.

Energy consumption at the facility before modifications were made was 2,846,000 kilowatt-hours per year. Actual consumption in 1982 was 1,843,000 kilowatt-hours per year which was within 3 percent of the projected level. Figure 3 summarizes the projected savings figures and actual installation costs for the project.

Cast History #2

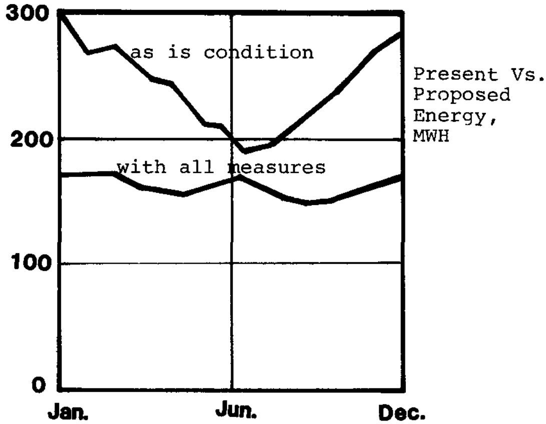
Facility Background:

The Tumwater Valley Racquetball Club consists of five buildings, including three indoor tennis courts, a gymnasium, and a racquetball building all totaling approximately 80,000 sq. ft. The racquetball building and gymnasium account for more than 80 percent of the energy consumption, therefore they presented the greatest savings opportunity. Energy usage in the tennis buildings is mainly for lighting since temperatures are allowed to vary over a wide range. Heating and cooling systems are made up of eleven 4-ton heat pump units. Hot water, which accounted for 21 percent of the facility's total energy consumption, was provided by a single 500 gallon, 120 kilowatt, electric

Table to Figure 3

Conservation Measures	Annual Savings Kilowatt-Hours	% of Total Consumption	$ Cost
Economizer Clg & Ctls	770,000	27%	$30,000
Interior Lighting	98,000	3%	10,000
Temperature Controls	90,000	3%	14,000
Exterior Lighting	44,000	2%	4,000
TOTALS	1,002,000	35%	$58,000

Figure 3



Conservation Measures	Annual Savings Kilowatt-Hours	% of Total Consumption	$ Cost
Wall Insulation	112,000	11%	$55,000
Heat Recovery	110,000	11%	12,000
Economizer Cooling	50,000	5%	19,000
Temperature Controls	46,000	5%	4,000
TOTAL	318,000	32%	$90,000

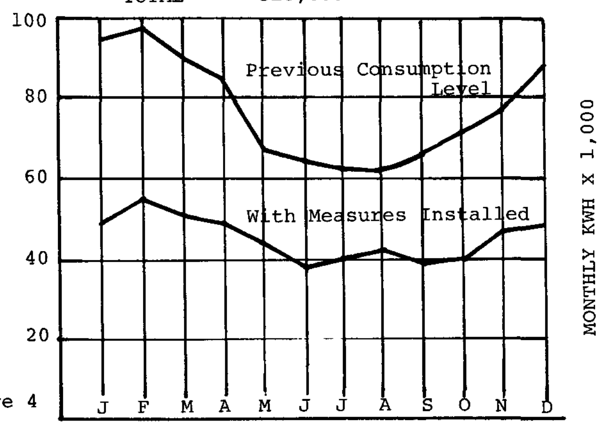


Figure 4

water heater. The lighting systems were predominantly fluorescent throughout.

Conservation measures installed at the facility included exterior wall insulation, a heat pump recovery system, night temperature setback controls and economy cooling.

Exterior concrete block and tilt-up concrete walls on the gymnasium and racquetball buildings were insulated using 4-inch thick expanded polystyrene foam boards applied to the outside of the walls. An adhesive is used to attach the foam boards to the concrete, and reinforcing fabric is installed on the outer surface to resist puncture and abrasion. A colored stucco surface provides the finish. The insulation has a resistance value of R-16 and heat loss through the walls was reduced by 84 percent.

A domestic hot water heat pump heat recovery system was installed which used $80^{\circ}F$ and 80 percent relative humidity air from the locker room exhaust systems as a heat source. Two identical heat pumps, one for each locker room, were installed. The heat pumps pick up heat through their evaporator coils located in the exhaust air stream. The heat is increased in the heat pump compressors and is finally removed in water-cooled condensers which can raise the domestic water supply temperature from $55^{\circ}F$ to $110^{\circ}F$. A pump recirculates the warm water from the condensers through a 350 gallon preheat storage tank and back through the condenser coils. When the preheat tank temperature reaches $110^{\circ}F$, the system cycles off. The main 500 gallon hot water tank is supplied directly from the preheat tank and the preheat tank receives cold water from the domestic water supply.

Night temperature setback in each heating zone was achieved by using field adjustable 7-day programmable thermostats as in the previous case history. Here also the extended night and weekend operating hours limited the available savings to about 5 percent for this measure.

The economy cooling system was designed to provide all cooling requirements when outside air temperatures are less than $60^{\circ}F$. Equipment and controls were installed which functioned in the same way described in the previous case history.

Energy consumption at the facility before modifications were made was 984,000 kilowatt-hours per year. Expected savings of 318,000 kilowatt-hours per year could not be confirmed on an equal basis since the facility underwent significant expansion soon after the measures were installed. However, the overall consumption is still less now than it was previously.

Figure 4 summarizes the projected savings figures and actual installation costs for the project.

SUMMARY

In addition to our aggressive commercial program, Puget has also provided a variety of residential energy management programs.

Electric space heating customers may be eligible for free home energy check-ups and weatherization financing for cost effective measures including insulation of ceiling, walls, floors, ducts, storm windows or insulated glass and heat pump space heating systems. Heat pumps were added to the program in 1982 and over 500 systems have been installed. The financing options available for these measures are the same as offered on the commercial program.

There are several programs available to customers with electric water heaters. They may receive a free water heater insulation kit which can be installed by the customer, or Puget will install it free of charge. To date over 200,000 of the kits have been installed. In 1982, we began a Solar Water Heating Program that provides $300 cash grants to customers who install a solar water heater. To date, we have issued over 150 grants. Presently we are piloting a "Water Heating Efficiency Program" which provides direct grants to contractors when they replace an existing electric water heater with a 'super-insulated tank,' install adjacent pipe insulation, install heat traps, and low flow shower heads.

To date, over 300,000 megawatt-hours will be conserved annually as a result of all our energy management programs. The energy saved will provide for the electrical needs of approximately 20,000 average residential households.

PROJECT FINANCING FOR COGENERATION AND OTHER LARGE-SCALE ENERGY EFFICIENCY IMPROVEMENTS

Jeffery B. Weinress

Energy Finance Group

HAMBRECHT & QUIST
Incorporated

I. INTRODUCTION

A. Since the first oil crisis in 1973, rising energy costs have focused attention on the need for improving energy utilization, either with equipment enhancing energy efficiency or through installation of cogeneration systems. Typical energy savings from such projects are 15-20% if not more. In many energy intensive industries like food, metals, forest products and petrochemicals, the savings, both in energy and cost, are substantial as are the returns on such investments. However, in many instances the company anxious to enjoy these benefits is unwilling or unable to provide the money necessary to develop such projects and turns to third party or project financing.

B. In this speech, I will attempt to cover three aspects of project financing:

1. The framework within which investors and lenders evaluate projects
2. Sources of capital
3. A perspective on such projects as seen from a financier's standpoint

C. Before you seek financing, you need to prepare a feasibility study of your project covering:

1. Project description
2. Raw materials or resource information, if applicable (may be an "energy audit")
3. Output and markets
4. Technology and engineering of your plant and equipment
5. A cash flow analysis
6. Proposed legal and financial structure
7. Management
8. Permits and other environmental aspects

D. There are three steps involved in translating a project's economics into a financing plan. These consist of the following:

1. Identifying and assessing the risks associated with a particular project.
2. Finding ways to allocate, mitigate or eliminate these risks, thereby developing an infrastructure whereby project risks are allocated in a mutually satisfactory manner to participants in the project.
3. Based upon this risk, finding the most favorable sources of capital.

II. GENERAL DESCRIPTION OF RISKS

A. **Completion risk** -There are two types:

1. The risk that a project will not be physically completed at a price reasonably consistent with original cost projection.
2. The risk that a project will be unable to initially produce the intended output or savings in a quantity and at a quality consistent with design specifications.

B. **Operating risk** - The risk that a project, having once achieved completion, will fail to continue to produce the expected quantity and quality of output at the expected cost and thus not able to generate adequate cash flow. This can arise from the following:

1. An inadequate resource or supply of raw materials either from a supply or price standpoint.
2. An improperly engineered process.
3. Equipment that fails to perform reliably.
4. Operating costs escalating more rapidly than revenues/savings.

C. **Marketing risk** - The risk that the output cannot be sold at expected prices due to a fall in demand or enhanced availability of a substitute product or technology. This might be a good point to mention the two common types of sales contracts often found in alternative energy projects:

1. The "hell-or-high-water", take-or-pay contract. This contract shifts the marketing and some of the production risk to the buyer(s) of the intended output; specified payments must be made regardless of delivery.

2. The take-and-pay or take-if-tendered contract. This contract obligates the buyer to purchase the output, but it does not transfer the operating risk to the buyer.
3. Naturally, the former is preferable from an investor's or lender's perspective because it substantially reduces the risk in a project after completion.

D. **Management risk** - The risk of being unable to attract and retain capable management team.

E. **Political/regulatory risk** - The risk that new or changed regulations or even government intervention will result in a project being unable to generate the cash flow expected or somehow effect the participants in a project.

F. **Financing risk** - The risk that a change in tax regulations or higher interest rates than originally envisioned will result in the project's inability to generate its expected return or service its debt.

III. SOURCES OF CAPITAL

Once the risk is analyzed and allocated, the questions is where the capital will come from and in what forms should it be deployed? To start off, it is important that you recognize that the financing for such a project is going to be determined by the nature of your participation in the project. Here your options include:

A. **Direct Ownership and Operation:** While an industrial or commercial concern can own and operate a facility, retain the tax benefits and finance it with internal funds, external funding can be obtained with limited recourse.

B. Such limited or non-recourse financing generally involves what is called "**project financing**". This involves "financing a particular economic unit, where investors and lenders are compensated solely from the cash flow of that unit and hold the assets of the unit as their sole collateral". Unlike other forms of financing, where a guarantee is generally required for the life of the transaction, the project financing participants mitigate their risk through a series of contracts which assure the functioning and profitability of the project. The characteristics of a successful project financing are:

1. Backed by a creditworthy party(s)
2. Allocates risks in a mutually acceptable manner
3. Strong financially
4. Technically sound
5. Capably managed
6. Relies on supply and sales contracts which are strong in content
7. Built by a capable, experienced contractor
8. Has assets which have value as collateral
9. Takes place in a favorable political environment and obtains all regulatory approvals
10. Adequately insured

From a lender's perspective the two problems most frequently encountered in arranging project financings are:

1. The sponsor's inability to provide satisfactory completion guarantee/support
2. Arrange long term supply and sales contracts lasting at least the life of the loan

Besides commercial lenders, the debt in such projects often comes from another source: **tax-exempt revenue bonds.** California, Maryland, Oregon and New York have recently established state entities with authority to issue tax-exempt bonds to finance energy conservation and alternative energy projects, including cogeneration projects. However, to the extent you finance a portion of your facility with tax-exempt financing, the portion of the project so financed generally does not qualify as an investment for purposes of the Energy Tax Credit because of what is called the "double dipping" provision enacted as part of the Windfall Profits Tax Act.

C. **Transfer of Tax Benefits through Leasing:** When a company wants to operate the facility and requires some external financing, but does not need all of the tax benefits of ownership, then leasing may be the appropriate means to accomplish these objectives. Don Kitteridge of Citicorp Industrial Credit will discuss this financing technique in more detail.

D. **Third Party Ownership and Operation:** If the energy user does not want the operating responsibility, risks or tax benefits of ownership, third party ownership and operation can be arranged. Increasingly, energy services companies and similar structures involving utilities or A&E firms/construction companies are being used for this purpose.

E. Finally, **insurance** has an important role to play in project financing. Any project needs to be adequately insured. Business interruption insurance is very useful in mitigating the operating risk of a project. Furthermore, insurers can now be enticed to assume substantial risk in energy conservation projects by guaranteeing the savings or improved efficiency of a plant over an extended period. However, such insurance is expensive and may not induce investors and lenders to participate in a project. Everyone wants to finance successful projects. Having to go to an insurance company to collect a large payment, however, is not a situation anyone wants to find himself in. The risk of protracted litigation is too high. Nevertheless, this is an option worth careful consideration and frequently used in revenue bond financings.

IV. A PERSPECTIVE ON PROJECT FINANCING

A. **Cogeneration** is recognized today as the most mature, lowest cost (on an installed kilowatt basis) and well developed of the alternative energy technologies. Hence, it is the easiest to finance. Given the maturity of this technology, the most significant aspect of cogeneration relating to financing is the fact that many cogeneration facilities use natural gas as a fuel in a time of regulatory change. Consequently, the economics of such projects can be difficult to gauge. Unless product prices are tied to resource prices, operating risk may be hard to mitigate.

B. Turning to **energy efficiency**, the key question here is whether the energy savings are for real. Many people are skeptical about savings from energy efficiency equipment, particularly from the more technologically sophisticated "black boxes". Not many people have seen energy savings documented in a way that adequately demonstrates the savings resulted from the installation of energy equipment. It is easy to understand the value of a cogeneration facility which produces a fixed amount of steam and electricity. Energy savings are more ephemeral. Measuring energy savings requires accurate and periodic calculation of energy use that would have been incurred but for the new equipment. The credibility problem of energy savings devices must be overcome before investors and lenders will commit themselves to financing such equipment.

C. There are **additional barriers** that also need to be overcome:

1. There is considerable uncertainty regarding the tax benefits associated with such projects. This often results from unclear statutory language, the lack of IRS regulations and rulings on many of the pertinent issues, as well as the lack of experience among professional tax advisers on issues relating to the appropriate tax treatment for equipment improving energy efficiency.
2. Energy savings are difficult to "bank" since the savings are not captured. They come in the form of lower utility bills, not cash that can be used to service debt and reward investors. Similarly, even though the energy user may not directly support a financing, his continued operation is essential for a successful project. Hence, he will have to meet high standards for a project financing to proceed.
3. Lenders are generally not willing to accept energy efficiency equipment as the only collateral for a loan: it is difficult and expensive to remove; there is no readily identifiable market for used energy efficiency equipment.
4. The cost of arranging project financing is high. Professional fees can often amount to several hundred thousand dollars. Consequently, a project should be several million dollars in size to justify incurring these expenses. This eliminates the practicality of such financing for many projects.

V. CONCLUSION

Despite these problems, many financial institutions are interested in financing cogeneration and large-scale energy efficiency projects. They see investment in this area mounting rapidly and are anxious to participate in these opportunities. However, until interest rates come down further, energy costs level off or increase again, tax aspects are clarified and governmental financial incentives are developed to make energy saving investments more attractive, you must carefully choose where you seek financial assistance and be prepared to commit the considerable time and effort it takes to arrange a successful project financing.

COST EFFECTIVE METHODS OF ENERGY CONSERVATION IN APARTMENT COMPLEXES

JOHN DARCY BOLTON

PRESIDENT, COMPREHENSIVE ENERGY MANAGEMENT

ABSTRACT

The paper introduces a brief consideration of the extremely large market potential that apartment complexes represent and the advantages of marketing energy services to apartment owners. There is a discussion of separate billing of residents followed by specific lighting and motor improvements that will save energy and have proved successful in experience. Perfect combustion and measuring combustion efficiency is considered along with some specific changes that can be made in apartment complexes. The paper closes with consideration of problems in solar design and installation.

I am very pleased and deeply honored to speak to such a prestigious body as the National Energy Conference pleases me very much and I am deeply honored. I understand that many of you have come from great distances to hear the speakers and see the equipment. I appreciate your coming and I will try to see that it is well worth your time and cost. My topic and my backround are in apartment buildings. I have owned and operated apartment complexes for more than twenty years and now I operate my own business, Comprehensive Energy Management, that provides services to apartment owners as well as other energy users in Irvine, California, where, unfortunately, the sun always shines, there is no winter, and energy costs are far too low.

APPRAISING THE MARKET

If you are like me, you like to fish where the big fish are so in your business you tend to direct your promotional effort to large installations like schools, hospitals, and plants owned by national or even multi-national corporations. Due to the fact that their energy bills are very large, time spent in trying to reduce them will always reap rewards. Frequently they have very wasteful systems so there is a real opportunity to save them very large amounts of money.

Apartments offer a far far larger market potential, albeit a more diffused market. In the United States there are 7,000 hospitals, 106,000 schools, but there are 12,910,000 apartment buildings larger than five units. Clearly the potential market is huge. There is far more energy both used and wasted in apartments than in public buildings. Only 5% of apartment owners have ever made any energy saving alteration. There is clearly a great deal left to do.

Besides size of the potential market there are some other advantages to seeking apartment business. Apartment buildings are operated by the owner, and decisions are frequently made by him instead of a distant committee. You can deliver your message once and often have a decision right then and there. Another big factor is the fact that apartments are operated for financial reasons and the owner is interested in saving energy, if only for financial reasons. Most other large institutions are operated to attain other goals and the financial side of things is often overshadowed by other more pressing considerations. Schools and hospitals frequently get grants to cover costs and there is little incentive to reduce costs in that situation.

THE ENERGY SURVEY

It is absolutely mandatory that every energy project commence with a survey. There is just no other way to advise an owner of what steps are possible, what steps are cost effective, what are no cost measures, what are low cost measures.

A good and careful survey takes a lot of professional time. At one point my firm did the survey free and we found we were doing a whole lot of surveys and little other business. Now we charge for the reasonable value of the time involved and it runs between $200 and $500 for an average apartment building. Unfortunately there are no short cuts to a good result. It takes a skilled person with enough time to go through the whole building and count each light, measure each motor, do a gas analysis on their heating device, look at the insulation and review the bills for at least the past year.

We produce a book for our customer that discusses each area of energy consumption including what average costs are for installations similar to his, what his costs are, what can be done, what should be done if anything, the cost of any changes and payback time. There is also a table of suggested changes arranged by time of pay back, with shortest first. I do all this on a word processing computer that has the basic text in its memory. As each situation arises I write in the alterations and the specific numbers for that customer. Many times the customers don't understand what is in the report and the result is a failure because there was no follow through. I insist on presenting the finished report to the customer and reviewing it with him. That assures me that it was read, understood and considered.

REVIEWING UTILITY BILLS

It is very important to review utility bills going back at least a year. The one year picture avoids basing changes on some unusual or seasonal anomaly and allows the energy surveyor to plot gradual changes such as those we see as boiler tubes gradually scale up. Don't forget to review the rate picture. We do occasionally find customers on the wrong rate.

CHANGING THE BILLING.

The easiest way to get the bill reduced is to have most of the utility costs billed to someone else; all of the costs if you can. Apartment owners do it for financial reasons, not to save energy, but there is an energy saving because once the residents start to pay the bill the amount of energy consumed goes down.

It is common, especially in older buildings, built when electricity was one cent a kilowatt-hour and gasoline was a quarter a gallon to have one meter for the whole property. It was cheaper at that time to pay the bill on behalf of the tenant than to suffer the alternative cost which was separate feed lines to each unit with separate meters on each line.

Now utility costs are so high and rising so fast it pays to switch over to separate metering no matter what it costs. There are two kinds of re-metering jobs, the easy ones and the hard ones. Fortunately most of them are the easy ones. In these cases the apartments are individually wired and the breakers are all fed by one master meter. Here we can just add one meter to feed the breakers for each apartment. The hard jobs are where the electrician wired all the north wall on one breaker, all the central wall on another and the south wall on another. In these hard cases we have to go in and re-wire each apartment and separate it from the rest. It is a big job and it involves a whole lot of broken plaster. It is seldom possible to estimate these jobs in advance.

When faced with this decision, apartment owners frequently express fears that it will make it harder to rent the units. My experience is that it has no measurable negative effect on renting apartments. Tenants continue to consider other major factors like location, amenities and transportation in the decision to rent and relegate utilities to a minor consideration.

Utilities are a relatively small expenditure for the average tenant. It is the owner who must pay the bill for everyone that faces a huge bill. When a very large bill is divided among all the residents, the cost that individuals pay is relatively small. Tenants frequently get a preferential rate and the bill is very likely to be much smaller once the tenant realizes that he is paying the bill. Suddenly he can remember to turn off the heat or air conditioning during the day when formerly it always just slipped his mind.

REDUCING ELECTRICAL COSTS

1) LIGHTING

A typical apartment building uses relatively little electricity. What little is used is used for lighting. The one exception to that general rule is if the owner provides central air conditioning.

The easiest savings can be achieved by eliminating as much light as possible. This can often be done in public halls and walks. Buildings are, in my opinion, better designed with exterior walks if the climate permits. If the building already has interior halls much of the lighting can be eliminated with the addition of windows and skylights. They have the advantage of eliminating the discomfort and claustrophobic feeling one frequently gets in windowless halls. A few plants make a real improvement in the look of the whole area. Mirrors spread the available light, make the rooms look larger, and do the job for years and years at no operational cost at all.

Everyone here knows about more efficient lighting but it is surprising how few apartment owners realize how much they can save by switching from incandescent to fluorescent lighting. You can make a very convincing argument by showing them brochures from prominent companies like Sylvania and GE with lumens per watt and projecting those numbers to dollar savings for their public areas. I do not favor low pressure sodium lighting because the color is so offensive to residents and there is evidence of health hazards if someone was to spend a great deal of time trying to see under those lights. I have had good experience with both owners and residents with high pressure sodium lighting so it represents to me the best compromise between cost and comfort.

I must sound one important cautionary note here and that is about the amount of light in the public areas. Local codes, recent court cases following suits for injuries and the Society of Illuminating Engineers all proscribe something in the range of three to five lumens as the minimum acceptable light. That means at least three lumens in the most poorly lighted areas. Before you leave the job site it is imperative that you have at least that in the darkest corners, behind the tree and perhaps hardest of all, between every car. It is between cars that people frequently trip and fall on unseen objects and holes in the pavement. It also makes a perfect place for an assailant to hide because the cars hide him from view. Without abundent light in these hard-to-light light areas the owner and the engineer who put his name to the job can be successfully sued even many years after the job completion. The solution is to install lighting on poles and take the extra time to walk around with a light meter measure the result after the job is done.

Public lights on most apartments are cycled on and off by clocks. The limitations of clocks are that their time keeping ability is destroyed by power interruptions. In your own home that would be a minor inconvenience quickly corrected by re-setting the the clocks. In an apartment house with a non resident owner and a feckless manager the clocks remain out of time for months, turning on the lights at noon and off at midnight. Another problem is that clocks should be advanced about two minutes each day in the autumn and retarded about 2 minutes in the spring to allow for the changing length of daylight. Of course that is only done sporadically. The result alternates between wasted electricity and the generation of very hazardous conditions for lack of any light at all. At the risk of being accused of over-kill let me add that clocks cannot turn lights on in darkest areas first and hold lights off in brighter areas nor can they turn lights on earlier on cloudy mornings and off earlier on sunny mornings.

The solution to all this is individual electric eyes. They are not inexpensive, not effected by power failures, can turn lights on earlier in dark areas, earlier on cloudy mornings, off earlier on bright mornings and they don't need to be reset for seasonal changes in length of day. There are many advantages and they save enough electricity to pay for themselves.

2) PUMPS AND MOTORS.

The only other electric consumption that a typical apartment building has is motors to power hot water circulating water pumps. Most people, and most apartment owners in particular, don't realize how much electricity motors consume. They consume roughly 1000 watts per rated horse power. Even at our relatively low California rate of seven cents a kWh that is over $600. per year.

The easiest way to save on anything is to turn it off and pumps are no exception. We have had good experience with clocks that shut off hot water circulating pumps in the midnight to 5 AM time period. When a resident needs hot water in that period he just has to leave it run a little longer. That shut off period gives the owner not only a 25% saving in electricity but also a substantial savings in hot water costs. The long hot water lines in apartment buildings lose a great deal of heat. Allowing them to stay cold 25% of the time cuts line losses to zero in that period.

I want to re-tell an anticdote about motors that I heard at this conference last year. It seems that two salesmen were competing for an order for a 100 hp motor. The salesman from Company A was offering his for $3400 and the salesman from the B Company was offering his for $5400. The single difference in motors was that A's was only 90% efficient and B's motor was 96% efficient. Assuming a seven year life and six cents a kWh which is the better bargain? If one takes the time to work through the calculation, B's higher priced motor is a better bargain.

How much would A have to take off his price to make his motor competitive? The cost of electricity for seven years plus the cost of B's motor is $291,358. A has to get his cost for motor plus electricity consumed to the same number. Cost for electricity for the A motor under the same parameters is $304,998. In order to be competative A would have to give the customer the motor free and reimburse $13,640 to use it. The moral of the story is that it pays, very well indeed, to pay whatever it costs to use the motor with the highest possible efficiency.

In choosing more efficient motors let me urge the buyers to see that they are rated in accordance with NEMA standard 1EEE112. Motor manufacturers can devise their own rating system that makes their motor appear to be more efficient than it is.

SAVING ON FUEL

I think it is obvious to everyone that shutting things off and carefully insulating saves fuel so I will not belabor the points by spending a great deal of time on this issue. It is sufficent to say that double glazing windows, sealing drafts, installing automatic door closers between heated and unheated areas all pay rich dividends. Be sure to pay attention to hot water pipes because their metal surfaces lose a great deal of heat. Restrictors in shower heads save hot water but they encounter some resistance from residents. I have had good experience with a shower head made by Moen. A typical shower releases about five gallons of water per minute, the Moen head only releases two, and you really can't tell you are getting any less water.

Reducing the amount of exposure to heat loss is nearly as is important turning things off. Try to get the hot water lines as short as possible even if it means moving the equipment to the most central location possible. The job is not as large as it might first appear since many of the same pipes and ducts can be re-used without moving them. Hot water that formerly came from the boiler in the basement to the third floor for example, now goes from the third floor down to the basement in the same lines. The direction of flow is reversed but the lines are neither moved nor changed.

Another important energy saving step is to match boiler size to need. It is very common to find an owner operating a huge boiler intended for winter space heating to supply domestic hot water needs in summer. The first and last minutes of each heating cycle are almost entirely lost. When there is a huge boiler that cycles on and off for short periods more than half the heat bought can be wasted. Substantial energy savings will result from having a very small hot water heater that runs in very long cycles.

It is always well worth your time to monitor an owner's combustion process no matter what his chosen fuel is. In ideal circumstances all the carbon in the fuel is converted to water and carbon dioxide with the liberation of heat and all the heat is absorbed by the heated medium. Of course that never happens. Fuel is a variable substance and the adjustments on the boiler are fixed. Fuel particles are never small enough for perfect combustion and mixing of fuel and air is always less than perfect. The air pressure, air temperature and moisture content all vary. Heat absorbing surfaces get dirty. There is wear and all too frequently, fundamentally poor design in the fire box.

As part of the first contact with the owner I always measure the efficiency of his combustion devices, that is, his hot water heater, boiler or furnace, if he has one. I have a portable unit made by Teledyne that measures oxygen and unburned fuel in the flue. I have a separate device that measures temperature. From fundamental calculations or from a table supplied with the unit, I can determine the efficiency of combustion.

Obviously there should be no unburned fuel in the chimney stack because that fuel was bought and paid for by the owner and is escaping without doing him any good. In the case of gas users, unburned gas in the stack represents a serious explosion hazard. The flue temperature should be as low as possible because all heat there is heat lost. There should be no oxygen in the flue gas because any there went through the flame chamber, was heated for nothing along with the inevitable nitrogen, and both are now being thrown away.

In practical terms there is no way to get zero oxygen and zero unburned fuel in the chimney stack. One of the problems is that mixing of the air and fuel mixture is always imperfect to some degree. As you approach zero excess of either, you always get some spots of excess air and some of excess fuel. Excess air is much safer and less costly than excess fuel so opt for about 5% excess air. There has to be some temperature rise in the stack to get enough convection force to push in the air and draw the waste gasses out. Most people think that about 125 degrees above the heated medium is about the lowest practical flue temperature.

I have often found small units to be wasting 50% of all their fuel, so checking efficiency is time well spent. In those cases I have a very happy owner and a friend for life. Larger units can vary 3% or 4% every month, so it is well worth a monthly trip to adjust them. On larger units be sure to adjust at all steam loadings since good efficiency at one loading does not guarantee good efficiency at any other loading.

Local gas companys and others sell blankets that insulate the exterior surface of a hot water heater and are said to reduce heat losses. Every hot water storage tank I have ever seen was made with built in insulation so surface losses are minimal. Major losses occur in the chimneys that run through the core of the water storage tank. A typical heater only ruins about two hours a day. For 22 hours a day relatively cold ambient air drifts through the combustion chamber and up the flue, constantly being heated by the stored water. Of course the water loses heat and that heat has to be replaced by burning more fuel.

A big improvement in energy equipment came with hot water heaters with a damper controlled flue. When the flame goes off the damper shuts off the chimney vent. It prevents the heat losses associated with convection and it also holds the hot air from the last few seconds of burning inside the combustion chamber so that the last of the heat can be extracted. Normally the momentum of the air column whisks that hot air up the flue.

I want to urge every one involved with the energy problem to consider alternate fuels. In many cases the producer of that fuel will consider it waste and will actually pay to have it removed. For the purchaser of fuel it can yield abundent fuel with a negative price tag. Some alternate fuels are waste oil, cleaning solvents, furniture factory waste, and used tires.

SAVING ON WATER

Water is not strictly speaking an energy problem, but owners have to pay a charge for it and they are happy to see it a smaller bill. Water bills have doubled in the Los Angeles area over the last few years and since proposition 13 they have added a separate sewer charge. In their three fold growth the bill has gone from a minor consideration to an important one for owners. The good news is that if you can reduce consumption you can save twice, once for the water charge and again for the sewer charge which is based on water consumed.

The first and easiest step is to repair all leaks, dripping taps and toilets that won't shut off. The next step is to install restrictors on showers and aeraters on sinks. Aeraters add air to the water and make a small flow look larger to the user.

I have tried several toilet restrictors without much success. You can save a little by bending the toilet arm so the tank doesn't quite fill high or you can put a plastic bag filled with water into the tank. I have tried a product cleverly named Watergate which is two springy plastic water dams that you insert in the bottom of the tank. They hold back about a half gallon each in the corners at each flush. The advantage of the water dams is that you get the same distance of water drop for good flow as previously, but with less water. The fact is that when you take a product that was designed to use five gallons of water per flush and try to make it operate on three gallons you get problems in removing all the material. The best solution and unfortunately the most expensive solution, is to change the toilet to one that is designed to operate on three gallons per flush. Oten it pays to do that.

I have looked into gray water holding tanks and at this time I think they are too expensive to offer a reasonble pay back. This system holds water from showers and sinks and uses it to flush toilets. The cost gets out of hand fast because it involves the owner in two waste water plumbing systems, one to collect sink water and a separate one to discharge toilet water, two feed systems, one for showers and one for toilets, and a pumping and filtering system.

PROBLEMS WITH SOLAR HEATING INSTALLATIONS

Solar domestic hot water is a cost-effective energy savings measure, especially when you consider the generous tax benefits. The matter of the design and installation of solar heating systems has been well covered by numerous speakers at this and other conferences so I will not spend any time at all on the matter of design. There are so many books on the subject that one could avoid the need for solar heating and obtain adequate heat for many years by just burning the books. I would like to spend the few remaining minutes by considering some of the problems encountered with solar installations, particularly with start-up.

In the initial stages the designer should carefully consider the problem of load. Solar panels don't weigh a great deal, but when they are filled with water they can weigh more than the roof designed to carry. The designer should also consider the problem of negative load in high winds. The panels are large, thin, flat surfaces very similar to an air plane wing and in high winds have a distinct tendency to rise up with portions of the roof and fly away. A connected problem is the integrity of the roof surface. It may well resist the load on a calm day, but movement of the panels and supporting structures in wind and by daily expansion and contraction due to temperature changes can destroy it. Occasionally solar panels impede drainage and that should be considered too. Avoid installing the panels so that they touch the roof surface. The movement is hard on the roof and the moisture build up can rot the panels and the roof members.

The first fill is always frought with problems. Never fill a system at mid-day. When solar panels sit in sunlight without a cooling medium removing heat they are said to be stagnated. The panels might be as high as 400 or 500 degrees. Introducing cold water at this time can destroy them. Stagnation of the panels occurs when they are new and not yet used with the heating medium. Stagnation is a risk the whole time they are in use. Pump failures, electrical failures, pipe ruptures all produce stagnation conditions. It is necessary that the system be designed to withstand these conditions. Systems should be filled at dawn to avoid damage due to high heat stagnation conditions. Violent boiling, excessive thermal shock, degradation of metal surfaces, un-soldered joints are all products of introducing cold water into 500 degree panels.

It is important to fill slowly to avoid air locks. An adequately designed system will have plenty of vents, but there is never enough. The fluid should meet the manufactures specifications especially with regard to ph. Fluid of the wrong ph will dissolve the panel by galvanic corrosion. The fluid should be filtered. All particles tend to collect near the bottom, and although the solids content of domestic water may be very low it can block the panel. Scaling and the deposit of calcium salts is a related problem that can be avoided by adding a water treatment.

FINANCING CHANGES

The nice way to go is to have the owner hand you a check for the full amount on completion of the work. There is getting to be very few of those kinds of owners left. A little innovative financing will frequently make changes happen that were impossible with a traditional approach.

An obvious one is to share the savings with the owner. I regret to say that my experience has been very unhappy with this method. I have a hard time to get the bills because they won't send them, it involves a lot of time to calculate the changes and when the rate changes you can expect an argument. It is very hard to explain that more is really less. Another problem that is very hard for everyone including owners to control is the matter of increase in the number of residents. In hard times families move in together and of course they use more heat, more hot water and more electricity. There is no way to know how many people are actually living in the property. When the changes are made that were supposed to make the bill go down and it goes up you can count on a very hard time getting paid.

A lease of equipment where the fee is based on savings has worked out fairly well in many cases. Under this plan the changes are made, the savings are established at the time of installation by the owner or an independent auditor and the monthly lease fee is set based on the savings realized. It could be half or any other portion. A variation is to have an independent investor buy and lease the equipment. Under this plan he gets a return on his investment and the very generous tax savings benefits that are accorded energy saving equipment.

CONCLUSION

In conclusion let me say that apartment buildings represent a vast, largly untapped market for energy consultants. The decision maker is easir to locate and more receptive to our message than the administrators of many other kinds of buildings. They use and waste vast quantities of energy so time spent in this area is time well spent.

I thank you for your kind attention and I wish you every success in your endevours.

BIOGRAPHY

Mr. Bolton grew up in Canada where he attended Carleton University in the faculty of Science. For the last 20 years he has owned and managed apartment complexes. He was the director of the Canadian property Managers Association and later the American Property Managers Association.

He is president of his own consulting firm, Comprehensive Energy Management at Irvine, California. He is attached to the Hospital Council of Southern California, is a Certified Energy Auditor by the State of California, is a licensed general contractor and a member of the American Society of Heating and Refrigeration Engineers.

INDUSTRIAL ENERGY CONSERVATION IN DEVELOPING COUNTRIES

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ABSTRACT

Developing countries faced with severe limitations of hard currency to purchase oil are attempting to develop indigenous energy resources and initiate conservation measures. Industries in these countries also desire to improve energy productivity in order to keep the cost of their products competitive in world markets. Unfortunately, a number of barriers exist which have slowed conservation momentum. Perhaps the most critical has been the lack of trained personnel to conduct energy audits, to identify energy conservation opportunities and to initiate and sustain effective conservation programs.

In order to address this problem, the Institute of International Education, sponsored by the U.S. Agency for International Development, has instituted a series of practical energy conservation training programs for industry plant engineers from developing countries. The first 8-week course was conducted at the University of Tennessee with the cooperation of the Tennessee Valley Authority and Oak Ridge National Laboratory. Thirty participants from fourteen countries learned the principles of plant auditing, economic analysis of conservation measures and methods to identify energy conservation opportunities. An attempt was made to combine practical with theoretical experiences.

The course also provided insight into possible areas for American firms to find markets for products and services in the developing countries. This paper describes some of the market areas identified.

INDUSTRIAL ENERGY CONSERVATION IN DEVELOPING COUNTRIES

The sharp increase in the cost of petroleum fuels has created a heightened need for developing countries to develop indigenous energy resources and improve the efficiency of energy use. The World Bank estimates that the LDCs in 1980 imported about $50 billion (1) worth of oil and petroleum products. Consumption has been growing at a rate double that of the developed world. With the downturn in the world economy, the developing countries are confronted with new problems. On the one side, declining economies in the industrialized countries mean that developing countries have greater difficulty in finding international markets for locally produced goods. This limits their capacity to acquire hard currency to purchase fuel and slows or halts progress in development. On the other side, today's strong dollar relative to local currencies means that oil and petroleum products are more expensive to buy. Even though the world price for oil is stable or slightly declining in real terms, the LDCs must pay for it in dollars which are costlier and harder to come by for them. The result is that many countries are forced to curtail imports of oil and equipment necessary for economic development. It has also resulted in additional borrowing from international lenders to finance oil purchases, to service debts and in massive debt rescheduling on the part of banks to keep national economies afloat.

With this in mind, LDCs have been making strides since 1973 to explore for and develop domestic energy resources. A review of more than 20 national development plans reveals a consistent theme: to spend a significant fraction of domestic funds to develop indigenous energy resources whether they be hydropower, oil, gas, coal, lignite, peat and other resources that are often overlooked in the developed world. While many of these plans are optimistic in terms of technical and financial capacities, countries are making their best efforts in these directions.

Those countries which have been fortunate enough to have discovered significant fossil resources have been able to attract multinational companies to provide financial and technical assistance necessary for their development. Other countries where local resources are

(1) World Bank, Energy in the Developing Countries, August 1980

only sufficient in quantity or quality for domestic markets have not been so fortunate as to be able to attract such companies. These countries have turned to commercial and development banks and bilateral donors for assistance. The resources available are insufficient to meet all of the demands on them. More recently, like the developed countries, these countries have realized that energy conservation is a necessary component of a nation's energy strategy.

The U.S. government, through the Agency for International Development (AID), has recently begun to provide assistance to LDCs in their efforts to develop indigenous, conventional energy resources. One program, the Conventional Energy Training Project (CETP), administered by the Institute of International Education, is designed to train technically qualified engineers, geologists, planners and other energy professionals from LDCs in current practices and technologies in various energy disciplines. The objective is to encourage countries to develop local resources by improving the skills of local personnel.

During the summer of 1982, IIE conducted an eight-week energy conservation course with the participation of the University of Tennessee, Tennessee Valley Authority and Oak Ridge National Laboratory. The course was directed at plant engineers in utilities and industry. It was very practical in nature, combining classroom work with field laboratories and workshops. A total of 30 engineers from 14 countries participated. See Attachment A for course outline.

During the preparation and operation of the course we learned about some of the problems in industry, the obstacles to conservation and the opportunities which exist to improve performance. We also learned of some opportunities for U.S. firms to find markets overseas. In this paper some of these lessons are described.

OPPORTUNITIES AND BARRIERS IN INDUSTRY AND UTILITIES

In developing countries industry, including utilities, is one of the major energy consuming sectors. Industry and utilities consume anywhere from 30 per cent to 65 per cent of a nation's total commercially produced energy. Typically, only a half-dozen industries dominate total energy use; these often consume up to 70 per cent of all fuels used in this sector. Furthermore, less than two dozen plants may consume up to three-fourths of the industrial energy use. Therefore, conservation measures which are directed at such industries can have a significant effect in LDCs where energy consumption is highly concentrated.

Despite the apparent opportunities, energy conservation has not generally taken hold in LDCs. A number of barriers exist which have prevented major conservation efforts. One of the most significant is that of perception. As it has in the United States, energy conservation has had a negative connotation in the developing world. Representatives of these countries argue that what is needed in their country for development and industrialization is more energy, not less. The now famous graph which relates per capita income to energy consumption for many nations shows quite clearly that the richer countries use orders of magnitude more energy per capita than the poorer countries to support their national welfare. In the last few years the industrialized countries have been successful in improving the energy productivity in manufacturing so that a unit of output requires less energy input than before. Without question the industrializing countries will require an increased supply of energy to fuel economic growth. The point, however, is that industrial and utility energy systems can be much more efficiently designed, maintained and operated than they have been in the past. The opportunity exists in LDCs for short term improvement in current operations and in long term investments for structural improvements. Only recently have national energy planners and policy makers, plant managers and engineers begun to understand the magnitude of these opportunities.

Other obstacles which have hindered the momentum of conservation efforts include:

- A lack of technical experience and training in performing plant audits, to identify energy conservation opportunities and to calculate the economic value of instituting such measures and to institute and sustain effective conservation programs.

- Management tends to resist tampering with processes which are familiar and have proven to work albeit inefficiently from an energy perspective. Management is averse to the risk of downtime associated with new practices since LDC enterprises often operate in an environment that already includes frequent shutdowns.

- There is strong competition for capital between expanded production, new product lines and structural improvements such as required for conservation. This is especially difficult in countries with high rates of inflation and low access to international markets because of trade barriers or lack of hard currency. Interest rates are often high and therefore economic justification is tougher than in developed countries.

- The high cost and long term resource commitment to switch from oil based fuels to other, less expensive domestically available sources of energy is often prohibitive to such projects.

ENERGY CONSERVATION MEASURES

In the short term, a conservation program can save substantial amounts of energy with relatively little investment. A combination of proper maintenance of plant equipment, an awareness of readily available "housekeeping" measures and training of responsible plant personnel can often achieve an estimated 20 to 30 per cent savings within a few years. Much larger improvements in efficiency following retrofitting of plants for recovery of waste heat and cogeneration can add significantly to this total.

- Energy Audits

  Few countries have begun to conduct systematic audits of plant facilities, including the measurement of key operating variables and fuel utilization of selected operations. In most plants organized and reliable data about plant energy consumption is unavailable. Instruments for energy audits are not readily available.

- Proper Maintenance and Housekeeping Practices

  Perhaps the simplest and most economical measures to achieve a quick return on a small investment requires improving maintenance procedures. The violation of proper maintenance practices is commonplace in LDCs where the pressure on plant engineers is to keep a plant running. Routine maintenance is often overlooked when the demand is to increase present production. Also, plant staff beneath the plant manager or engineer level is often ill-trained in standard maintenance procedures and record keeping. In one plant we observed, for example, after a furnace was repaired, replacement of the insulation cladding to a large section was neglected. This kind of neglect costs energy and money.

  Other standard practices such as monitoring for excess air, cleaning steam traps, etc. cost little but can significantly improve performance.

- Low Cost Improvements

  Low cost improvements such as adding or replacing worn insulation, installing task lighting rather than area lighting, metering (e.g. oxygen analyser) condensate recovery, additional heat exchangers, and combustion air preheating.

- <u>Moderate Capital Investments</u>
  Retrofitting plants with waste heat recovery equipment, replacing existing boilers, furnaces, and other equipment with more modern and efficient ones. Switching to indigenous fuel such as coal, lignite, natural gas. Using new efficient technologies including cogeneration, fluidized bed combustion.

- <u>Major Capital Investment</u>
  Redesigning the entire plant e.g. switching to alternative processes such as continuous casting in the steel industry and the dry process of cement manufacture. Developing indigenous fuels and hydropower resources.

- <u>Transmission and Distribution Line Losses</u>
  Perhaps the costliest loss to a utility in a developing country results from the large losses of electricity in transmission and distribution. In Pakistan, for example, line losses are reported to be close to 40 per cent of total power generated. Less than 10 per cent of this is from technical factors. The balance is from illegal hookups and unmetered usage. The solution to such a problem requires a strong management commitment and the legal and institutional resources to support a policy of tightened policing of distribution lines.

OPPORTUNITIES IN INDUSTRIAL ENERGY CONSERVATION FOR U.S. FIRMS

In almost all of the activities described above, opportunities exist for U.S. businesses. Specifically:

<u>Equipment Sales</u>

- Auditing equipment - a variety of portable instruments used in audit work are currently scarce in many developing countries. They include oxygen analyser (battery operated), "Fyrite" combustion gas analyser, smoke pump, Pitot tube and manometer, temperature probe, optical pyrometer among others.

- Waste heat boilers, combustion air preheaters, cogeneration sets, heat exchangers, waste burning boilers and perhaps fluidized bed combustion furnaces.

- Industrial insulation for furnaces, steam pipes.

- High efficiency electrical equipment such as in industrial refrigeration units, motors, compressors, lighting.

- Instrumentation to measure excess air, burner efficiency and other devices to monitor and control plant operations.

- Major capital equipment such as new boilers, energy efficient processes (e.g. dry cement).

- Equipment for conversion of plants to indigenous fuels such as gas, coal, lignite, peat, etc. or for the addition of new plants.

- Improved power transmission and distribution systems for both high and low voltage applications; high efficiency transformers to reduce technical transmission losses.

- Equipment and metering systems to reduce non-technical line loss due to theft of power.

Technical Assistance and Services

- Conducting audits, identifying conservation opportunities, selecting conservation measures.

- Developing national policy guidance for improved pricing of energy, developing strategies and legislation to encourage conservation.

- Engineering services in retrofitting plants with new equipment and designing improved efficient processes.

Training

- Energy auditing procedures, data collection and interpretation.

- Proper maintenance practices, scheduling, record keeping.

- Heat rate improvement, electricity load levelling, scheduling.

- Systemwide transition to indigenous fuel resources.

- Improved management procedures to encourage conservation and to sustain a conservation program.

CASE STUDY: TEXTILE PLANT IN THE PHILIPPINES

The Asian Development Bank and the Government of the Philippines are undertaking preliminary energy audits in 70 energy-intensive industrial plants with a follow-up of 20 detailed plant audits. The objective of the program is to identify energy conservation opportunities and to develop a data base for analyzing and developing energy policies.

The Philippines imports about 50 million barrels of crude oil per year. This accounts for about 81 per cent of total commercial energy consumption. Hydropower and geothermal energy account for an additional 15 per cent. Seventy-two per cent of the petroleum is used in the industrial sector and for power generation. Industry is the major consuming sector of electricity, accounting for approximately 40 per cent of total use. It can easily be seen that an intensive industrial energy conservation program could have a significant effect on overall energy consumption.

Starting in the fall of 1982, all large industrial, commercial and transport firms are required to report energy consumption and energy conservation efforts. For the largest plants, an energy manager must be appointed to file these reports and to encourage conservation efforts. Sample report forms are included.

The following case study of a textile plant illustrates the potential for conservation efforts in LDC industries. In this plant, a 15 per cent reduction in unit energy consumption was accomplished resulting in a savings of P 3.2 million (approx. $400,000).

This textile plant manufactures "ramie" fabrics and yarns. The primary raw material, ramie fiber, is derived from the china grass plant which is grown in abundance in a region of the Philippines. The steps in the manufacturing process entail (1) "degumming" the raw fibers by boiling the stem of the plant in caustic soda, making the fiber white and giving it a soft luster like silk; (2) the fibers are drawn to leave them even and parallel; (3) combing; (4) the combed fibers are twisted in bundles and spun into yarn; (5) weaving; (6) burning off raised fiber ends by passing fabric through two columns of flames and (7) washing, bleaching, dyeing and drying.

The firm established a conservation effort in 1973. It initiated a number of steps for which in 1981 it was awarded one of ten Outstanding Energy Conservation awards. The conservation measures are extracted from the Philippines' Bureau of Energy Utilization Quarterly Review:

- o Sun drying ramie fibers to reduce the moisture content from 50 per cent to 20 per cent; saving 840,000 liters of oil per year

- o insulating degumming boilers with asbestos; saving 140,000 liters per year
- o recovering 40 to 60 per cent of condensate and returning to boiler; saving 230,000 liters per year
- o installing Thermox Oxygen Analyser on boiler to reduce excess air and improve generating efficiency; saving 190,500 liters per year
- o installing a Voss economizer to use exit flue gas for heating feed water and improving boiler efficiency from 79 per cent to 85 per cent
- o adding capacitors to improve power factor, saving substantial amounts of money

Additional projects under consideration include:

- o converting from diesel to bunker oil-fired heaters
- o using coconut shells as a replacement for some oil
- o installing task lighting

ATTACHMENT A
Utility and Industrial Energy Conservation Training Course

2 Days Orientation (Cultural, Logistical and Introduction to Region & U.S.)

Week 1 — Introduction/Overview
- Elements of an energy audit
- Data Requirements
- Economic/financial analysis (cost benefit, life-cycle, simple pay-back, discounted cash flow)
- Maintenance practices
- Health, pollution, environment
- Common language of energy, conversion tables
- Use of calculator

Week 2 — Conduct Energy Audit (Industrial/Utility
- Useful forms for data collection
- Process flow diagram
- Material balance data
- Energy conservation opportunities
- Instruments for energy auditors (classroom and lab)
- Two (2) days in-plant "hands-on" audit
  - textiles
  - food processing

Week 3 — Combustion
- Thermodynamics
- Furnaces
- Heat recovery
- Use of industrial wastes
- Insulation
- Maintenance
  - wood and products; ceramics, kilns; paper

Week 4 — A. Boiler Plants
- Boiler efficiency
- Preheating combustion air
- Instrumentation
- Maintenance
  - 1-2 days in thermal power plant

B. Steam Distribution (Process Steam)
- Design of systems
- Insulation
- Steam traps
- Maintenance

Field Work - in plant work

Week 5 A. <u>Electric Motors, Lighting</u>
Specifications
Operating practices/maintenance procedures
Tour of power service shops (motor shop)

B. <u>Diesel Power Plant</u>

Week 6 A. <u>Heat Rate Improvement</u>
TVA program for heat rate improvement
Data collection and application
Performance data collection
Real time heat rate monitoring
Performance and capacity testing

B. <u>Reliability Improvement</u>
Outage data application techniques
Computer graphics
Techniques to predict unit reliability

Week 7 <u>New Technologies</u>
Cogeneration
Fluidized bed combustion
Waste fuel/wood fuel combustion

Visit power plants for scheduled maintenance.
Review audit techniques with additional audits (mining, chemicals)

Week 8 <u>Action Plan for Energy Conservation Program</u>
- motivating management and staff
- setting targets
- developing a reporting system
- identifying an energy manager
- developing a data base
- psychology of change in workplace
- training in-plant personnel
  - maintenance
  - operations
  - safety

First step on Monday morning when you get home

Individual case studies/problems from home.
Develop plans
Review

GRADUATION

ENERGY CONSERVATION
WHAT'S HAPPENING IN THE MID-WEST UNIVERSITIES

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HOME ECONOMICS
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The 10th Energy Technology Conference reminds us of the fact that this is the 10th year since the "Energy Crisis" in October 1973 when Saudi Arabia and other Arab members of the Organization of Petroleum Exporting Countries cut oil shipments to the U.S. Since then the world has been forced to adapt to a 12 fold increase in the price of a critical commodity that previously was largely taken for granted. That wrenching adjustment, forced by two traumatic oil shocks in less than a decade has, according to some economists, been the primary cause of recession and hard times for many in both the industrialized world and the developing countries. An article in the Business section of the Chicago Tribune on January 16, 1983, indicated that conservation and the continuing economic slump have combined to change the supply-and-demand equation; what was a shortage has become a glut, and oil producers now face doubts whether the current price levels for oil can be sustained. John K. McKinley, Chairman of Texaco Inc., said recently, "the record of 1982 provides solid evidence of the more dependable supply-demand balance.

Those who seek to document a fundamental change in the world energy scene suggest these facts:

1. Oil demand by Western industrial nations has fallen for three consecutive years with total world petroleum demand now being 20 percent below that in 1979. Efficiency

of oil use has improved about 28 percent in the seven largest industrial nations since 1973 raising doubts that an economic rebound will cause radical increases in oil rise.

2. U.S. imports account for about a third of our needs compared to a half five years ago with Mexico and Great Britain now replacing Saudi Arabia as our largest foreign oil suppliers.

3. Our nation's expected energy needs by 1990 are expected to be 40 million barrels per day rather than 55 million barrels a day forecast five years ago.

In contrast the International Energy Agency, a group formed by major oil consuming nations, including the U.S. warns that oil demand may exceed supplies by 1990. The executive director of this group, Ulf Lantzke said at least half the reduction in oil demand since 1979 is due to economic downturn rather than conservation.

For ten years now the controversies regarding the oil shortage have continued. Numerous studies have been done but many questions regarding the relations of supply and demand with almost continual energy cost increases. The cost increases make it essential for us to consider conservation practices but the unknown regarding the future supply and demand effects on energy cost make it difficult for colleges to project pay-back periods investments in conservation projects. The survey conducted last summer was an attempt to minimize the guessing by inquiring about projects completed at other Mid-West Universities. Most people agree energy conservation is a must if many Higher Education programs are to survive. Illinois public universities' expenditures for utilities increased by 65 percent between 1977 and 1981 fiscal year from $32.9 million to $54.4 million. During this time early efforts at conservation had reduced energy consumption by over 4 percent. Some of the public universities in Illinois have developed formal 5 year energy conservation plans with specific goals for achieving an average of 9.75 percent reduction during the 1981-1986 period. The estimated savings would be $2.2 million in FY1986 utility costs.

Many think the inexpensive "quick-fix" actions have already been taken. Ideas used by various campuses in the U.S. have been reported in numerous articles in journals, but it was difficult to identify ideas that were really applicable to Mid-West universities. In order to find data specifically for the Mid-West, a survey was conducted in cooperation with the Illinois Department of Energy and Natural Resources during the Spring of 1982.

This report summarizes data received specifically from 38 Mid-West Universities in Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin regarding their use of conservation ideas listed on a questionnaire. The questionnaire was sent to the Director of the Physical Plant at selected universities. In some instan where the university has an energy conservation officer, questionnaire was completed by that person.

The questionnaire dealt with administration, planning, and budgeting for energy conservation plus listing conservation statements for the entire university in addition to a section dealing specifically with the Food Services. Respondents were asked to evaluate each idea or measure already completed items at their school by checking either "very productive," "O.K.," or "of little value." This evaluation of conservation practices was done in an attempt to pick up clues of conservation factors that have been most productive.

Results of the study are available in the booklet titled "Energy Conservation at tHe Mid-West Universities" either from the authors or the Illinois Department of Energy and National Resources.

The need for effective communication in sharing information regarding energy conservation practices is essential for survival of the Universities when our energy costs have increased and our state tax resources are being reduced due to the recession and many competing demands for state funds. Going beyond the economics and conserving limited natural resources while now being a secondary consideration should be given higher priority.

Many ideas from this report are applicable to other state facilities as well as private institutions and businesses. Further study of the Food Service portion of the institutions seems critical in view of the relatively high energy consumption of this support facility to the University. While economic and administrative separations often exist between auxiliary services and the University as a whole, the electrical energy consumed does enter into pe load computations and consequently has a direct influence on the unit costs of electricity for the entire University.

Further information regarding specific conservation practices listed in the study could be obtained by contact-

RESULTS OF SPECIFIC DATA RECEIVED FROM 38 MIDWEST UNIVERSITIES

The first five statements on this questionnaire deal with the commitment of the university toward an energy conservation program.

Results from Participating Universities

STATEMENT	Was Done Approximately: 1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Has Been: Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
1. Now using a planned Energy Conservation Program.	4	12	14	22	5	1	2	2
2. Have developed Conservation Plan for next three years.	10	0	0	2	3	0	11	6
3. Have Energy Conservation Officer or some one with major responsibilities in this area.	5	12	10	8	5	0	3	1
4. Budget monies for Energy Conservation as part of: a. Operation and Maintenance	3	8	6	7	4	1	2	3
b. Capital Improvements	14	6	6	8	7	0	6	0
5. Have revolving conservation budget whereby some monies saved are available to future conservation projects.	1	1	1	3	0	0	0	20

The rest of this survey will show you how the responding universities are evaluating each statement or idea for energy conservation.

Situation:	1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
Conducted a "Walk Through Energy Audit" listing simple Operation and Maintenance Items (low cost or no cost energy conservation procedures).	10	7	7	7	8	2	3	2
a. Cracks and air leaks in walls and around doors and windows.	12	4	8	7	10	2	1	4
b. Water Leaks: 1) Dripping faucets in restrooms and utility rooms.	11	5	11	8	11	1	1	3
2) Urinals and water closets.	9	5	9	9	12	2	1	3
3) Drinking fountains.	6	5	7	7	10	1	0	3
4) Lawn sprinkling systems.	6	2	4	4	6	3	0	10
5) Water on floors - unknown source	7	3	8	5	4	2	1	7
6) Installed flow restrictors on showers	9	6	6	9	6	3	4	4

Results from Participating Universities

Situation - Continued	Was Done Approximately 1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Has Been Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
c. Steam Leaks:								
1) In boiler rooms or heat exchangers	10	1	11	8	7	2	3	4
2) In utility tunnels	8	1	11	10	6	1	3	8
3) At radiators and air makeup units	8	1	10	7	8	1	3	5
d. Insulation:								
1) Signs of excess frost or condensation on walls, windows, doors, etc.	3	4	7	5	5	1	4	7
2) Excessive heat in rooms or areas around steam and hot water lines.	7	5	8	7	5	1	6	3
3) Areas uncomfortable to employees or students	3	5	5	5	5	1	6	7
e. Excessive lighting:								
1) Unnecessary lights on during daylight hours or in areas not occupied.	8	3	10	10	5	5	3	2
2) Area appears brighter than needed.	9	9	4	11	8	0	1	5
3) Light meter check of illumination levels.	10	11	4	15	7	0	2	3
f. Temperature of rooms:								
1) During heating season.	11	11	6	10	10	1	3	3
2) During cooling season.	10	6	6	7	12	1	4	6
3) During seasons where heating and cooling are not necessary.	9	9	3	10	6	1	1	3
g. Equipment running and not needed:								
1) Electrical copiers, air conditioners, heaters, fans, coffee pots, etc.	8	4	6	2	8	5	4	9
2) Gas laboratory kilns, etc.	2	5	4	1	3	5	4	10
3) Water, laboratory, shower rooms, etc.	8	3	4	2	7	6	3	9

Results from Participating Universities

uation	Was Done Approximately: 1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Has Been: Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
3. Have central computer electrical peak load control system(s).	10	5	5	18	1	1	9	6
4. Include energy evaluations on all new construction and remodeling projects.	10	7	4	11	6	2	6	4
5. Trained custodial personnel in ways to effect energy savings, e.g. turn off lights and equipment, close draperies, etc., while doing routine duties.	13	7	8	13	11	3	3	4
6. Trained operation and maintenance personnel to monitor and adjust equipment for maximum energy efficiency.	12	10	8	14	8	0	0	2
7. Have procedures for receiving, acting on and rewarding personnel for energy conservation suggestions.	1	4	4	1	4	2	4	18
8. Have conducted contests between and among residence halls for energy conservation.	4	3	1	1	6	0	5	15
9. Transportation: a. Use carpool system.	8	7	4	5	5	7	3	11
b. Use compact or smaller more effective fleet vehicles.	16	8	3	15	6	1	5	5
10. Grounds: a. Plant trees, shrubs, etc. to shade buildings or break north winds.	4	2	7	3	5	0	4	15
b. Develop energy conservation program regarding maintenance of grounds and landscaping.	5	3	2	2	6	1	4	16
11. Heat recovery: a. Use heat recovery units from hot water from dishwashers, steam line returns, etc.	6	4	5	3	6	0	5	11
b. Use heat recovery units in ventilating exhaust and air make-up systems.	9	5	3	9	5	1	8	6
c. Use heat recovery systems from air conditioning, refrigeration and freezer systems to preheat water or space heat other areas.	7	3	0	5	1	1	4	16
12. Solar Energy: a. Use passive solar space heating in some buildings	4	3	2	1	4	1	5	15
b. Use active solar systems for: 1) space heating.	3	2	1	0	4	1	1	15
2) water heating.	1	2	1	1	1	1	3	21
Employ seasonal storage for heat and/or 'cold.'	0	1	1	1	1	0	2	27
14. Use off peak ice machine for air conditioning.	0	0	0	0	0	0	2	30
15. Use alternative transportation fuels.	5	2	1	2	4	1	4	20

ENERGY CONSERVATION IN FOOD SERVICE OPERATIONS*

Situations	Results from Participating Universities							
	Was Done Approximately			Has Been				
	1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
16. Food Preparation:								
a. Use timers and/or individual switches on food warmers.	4	3	9	3	11	1	1	10
b. Use time schedule for pre-heating ovens, steam tables, grills, broilers, fry vats, etc.	5	3	9	4	9	1	1	7
c. Stagger "turn-on" time for heavy demand electrical equipment.	4	1	1	2	3	1	2	13
d. Time use of backup fry units, broilers and ovens, etc. to coincide <u>only</u> with peak cooking demands.	5	1	4	3	6	1	2	8
e. Frequently check oven thermostats for accuracy.	3	2	7	4	6	1	3	3
f. Clearly post cooking capacities of ovens to maximize utilization.	0	1	5	2	3	1	4	12
g. Trained employees on efficient loading and use of ovens.	4	2	9	5	5	2	4	5
h. Check fuel to air ratio on all gas burners.	4	2	4	4	3	0	1	13
i. Reduce heat on Char-broilers after briquets are hot.	1	0	2	3	0	1	0	19
j. Adjust gas burner so flame just touches bottom of kettle.	2	1	4	3	1	3	0	16
k. Use lids on kettles to speed cooking process.	3	2	10	5	7	1	0	5
l. Place kettles and pots close together on range tops to decrease heat loss.	1	2	1	2	1	0	3	13
m. Place foil under range burners and griddles to improve operating efficiency.	3	2	2	1	1	2	2	14

*Some universities consider Food Services a separate enity not under the direction of the Physical Plant Director. Consequently, some conservation practices in Food Services at responding schools may not have been reported

Results from Participating Universities

	Was Done Approximately 1-3 Yrs Ago	4-6 Yrs Ago	Over 7 Yrs Ago	Has Been Very Productive	O.K.	Little Value	Planned During Next Three Years	Not Planned
17. Food Service Area								
a. Heating and cooking equipment located away from cooling equipment.	2	2	11	6	5	3	1	8
b. Frequently clean and check freezer fans and compressors.	5	2	12	6	9	1	3	2
c. Periodically check refrigerant, temperature controls and door seals on refrigerators and freezers.	5	4	10	7	8	1	2	3
d. Frequently defrost freezers.	2	6	7	5	4	2	0	8
e. Cut water heater temperature to 75^0 F. on closing and raise temperature to 140^0 F. 2 hours before use.	0	1	0	0	2	2	2	10
f. Frequently remove lime from heater coils.	0	4	9	8	3	0	2	8
g. Shut off electric booser heaters in dishwashers when kitchen is closed.	1	2	14	10	3	1	2	7
h. Insulate hot water lines.	3	4	11	8	5	0	3	3
i. Use heat recovery units on air exhaust system.	3	0	1	3	1	1	4	12
j. Use heat exchangers on refrigeration units to heat hot water or for space heating in winter.	1	1	1	0	1	0	1	18
k. Schedule delivery of frozen and refrigerated foods to minimize storage time.	2	1	9	7	2	2	3	6

ing the University named by each conservation practice listed. While actual savings can vary in different situations, i.e. the savings by changing lighting is directly related to the number of hours per day the light will be in use, the school listing the conservation measure worked out their own estimate of the savings derived and no attempt was made to analyze such data provided.

Inquiries from other universities wanting a copy of the report, and consideration by Northern Illinois Universitie's Energy Task Force of practices listed suggest the study is stimulating consideration for energy conservation in numerous ways.

ARMY ENERGY CONSERVATION PROGRAMS

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INTRODUCTION

The United States Army consumed approximately 18.0 percent of the total energy consumed by DoD during FY 82. Of that amount, 83.0 percent was consumed in fixed facilities and 17.0 percent was consumed in mobility operations. It is apparent, from consumption data, that the Army's greatest potential for energy reduction exists in fixed facilities. This paper focuses on Army Energy Conservation Programs entended to reduce energy consumption in existing facilities 20.0 percent by FY 85 and 40.0 percent by the year 2000, compared to the base year of FY 75. These reduction goals are to be achieved with no degradation of readiness.

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

Prior to 1976, the Army was performing piecemeal energy studies at various Army installations with good intent but random results. The Army recognized the need for a systematic approach directed toward the identification and development of energy projects to reduce energy consumption in existing facilities. Thus, in 1976, the Energy Engineering Analysis Program (EEAP) emerged. As of this date, most CONUS Army installations have been recipients of the EEAP basewide energy survey and commencing this year, European based Army installations will receive the audits. The fundamental objective of the EEAP survey is to determine the energy conservation measures required on Army installations. The EEAP is implemented through the Chief of Engineers based on Army Energy Policy established by the Army Energy Office. Office, Chief of Engineers has the responsibility, in coordination with the Army Energy Office, to develop annual EEAP programs. The actual program is managed by the Huntsville Engineering Division, Huntsville, Alabama. The Huntsville Division looks to the Geographical Engineering Division/District for program execution.

The basic EEAP approach consists of three phases:

- Phase 1, Survey and identification of high energy users.
- Phase 2, Analysis and application of energy conservation technologies.
- Phase 3, Submission of the study report to the installation's Director of Engineering and Housing (DEH).

Energy projects identified during EEAP audits are categorized and implemented in one of the following ways:

- Low or no cost projects

  Funded by the installation

- Major construction projects

  Funded through military major construction authorization, or through the operating and maintenance program.

- The remaining category of projects are those which qualify for funding under the Energy Conservation Investment Program.

ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

The ECIP provides the foundation for the Army Energy Conservation Program. ECIP is designed to promote energy conservation through the retrofit of existing facilities with economically justifiable energy projects. The Army expects ECIP to provide 12 of the 20 percent reduction goal for energy consumption per square foot in fixed facilities by 1985, from the level used in 1975, as required by Executive Order 12003 and provisions of the National Energy Conservation Policy Act (NECPA).

Typical ECIP projects include:

- Installation of building insulation.
- Thermal and storm window installation.
- Lighting alterations.
- Heating and cooling plant systems alteration.
- Energy monitoring and control systems and ventilation systems alterations.

ECIP projects are prioritized on the basis of the greatest life cycle payback as determined by the Savings to Investment Ratio (SIR). The SIR calculation is performed in accordance with the National Bureau of Standards Handbook 135, "Life Cycle Cost Manual for the Federal Energy Management Program." Since FY 76, Congress has appropriated in excess of $354 million for ECIP projects. Anticipated savings from ECIP, using then year dollars, exceed $68 million per year and 18 trillion BTU's per year.

ENERGY CONSERVATION AND MANAGEMENT (ECAM)

A program called Energy Conservation and Management is designed to provide energy-saving retrofit projects for Government-Owned Contractor-Operated (GOCO) plants. This program is analogous to ECIP and does for GOCO plants what ECIP does for Government operated installations. ECAM, which became operational in FY 82, is funded as an Army procurement program. The primary source of ECAM projects is the on-site studies performed under the Energy Engineering Analysis Program, although projects may also be generated by the Projection Base Modernization Program and other Army procurement funded initiatives. ECAM projects require the same justification and are prioritized in the same manner as ECIP projects.

FUEL CONVERSION

Executive Order 12217 (June 1980) directed Federal agencies to plan and budget for conversion and/or replacement of larger oil or natural gas fired boiler plants. Army boiler/heating plants range in size from residential types to large central heating and industrial plants. The present schedule of conversion projects include at least one large boiler plant per year. The cost for conversion/replacement of the more heavily loaded Army boiler plants will exceed $1.0 billion. Conversion to coal and/or solid fuel is essential to increase our reliance on domestic sources of energy that are available in large quantities. Current emphasis is being placed on coal, refuse-derived fuels and biomass since these fuels provide the greatest return on investment to reduce petroleum consumption. Coal is the predominant fuel based on fuel and equipment availability. Large central plants at an installation are proposed to reduce construction costs and the annual operations and maintenance costs.

Specific conversion programs include:

- A large biomass-fueled boiler under construction at Fort Stewart that will burn wood chips (wastes) from local timber harvest programs.

- Construction of a large boiler plant at Red River Army Depot that will burn wood chips or coal.

- Approximately ten boilers at Fort McCoy have been burning pelletized wood for several years.

ARMY ENERGY AWARNESS PROGRAM

A vital portion of the Army's overall energy conservation program is the awareness program. We have learned that energy savings resulting from dollars invested in building retrofits are maximized when complemented by an effective awareness program. The aim of the awareness program is to educate the work force as to what they can do to be more energy efficient and to solicit participation and support from the entire Army community for energy conservation.

The awareness program is a multi-faceted program that includes:

- Department of Army energy seminars.

- Energy workshops.

- Energy displays and various brochures and pamphlets on energy conservation.

Todate, the energy seminar has been presented to sixteen Army installations to include Hawaii. Energy workshops have been presented at approximately 20 CONUS and overseas installations. The energy display is sent world-wide for use at military and private energy exhibitions and technology conferences. The Secretary of the Army provides the finishing touch to the Army Energy Program by presenting an Annual Energy Conservation Award to Active Army, Army Reserve and Army National Guard installations with the most outstanding, energy conservation program during the previous year.

FACILITIES ENERGY RESEARCH AND DEVELOPMENT

The objective of the Facilities Energy RDT&E Program is to insure that the Army will be able to rapidly utilize the latest state-of-the-art energy technology in its efforts to reduce rising energy costs and dependency on critical fuels. Assuming that the major Energy R&D breakthroughs will come from DOE and industry, the Army's R&D program is directed at evaluating these R&D break-throughs, and rapidly implementing innovative technologies through an agressive technology transfer program. The Army Facilities Energy RDT&E Program is addressing new construction, installation energy conservation, and installation energy systems. New construction energy design research provide the means for optimizing the thermal efficiency of new facilities in all stages of the military construction process. Each stage from master planning, through design and construction, to final acceptance, impacts the thermal efficiency of the facilities delivered. The R&D program is aimed at identifying these impacts and providing the tools that are required to support energy consideration at each stage in the process. Installation Energy Conservation Research provides the technology that is needed to optimize the implementation of energy conservation in existing Army facilities to satisfy energy efficiency requirements. R&D is being done to provide technology to support facilities retrofit and energy management, and to develop procedures for identifying the best energy conservation opportunities.

Facilities Energy Technology Tests are to be conducted on Army installations to validate the performance and cost-effectiveness of the application of new technology to Army facilities. These tests will accelerate the exploitation of new technology by the Army to achieve reductions in energy costs. Four demonstrations scheduled to begin in FY 83 are:

- Post Wide Energy Conservation Demonstration of energy conservation opportunities and implementation of fixes that have been developed through RDT&E.

- Tests of Two Standard Buildings retrofits to achieve energy conservation through reducing electrical consumption, improving the efficiency of heating, ventilating, and air conditioning and building envelope modifications.

- Energy-Efficient New Building Demonstration to validate design, construction and initial operations of an energy efficient building.

- High Efficiency Residential Heating Systems Tests of feasibility of using new systems to reduce consumption of critical fuels.

CONCLUSION

In the decade since the OPEC Cartel imposed an oil cutoff, the Army has taken many initiatives to reduce energy consumption. The programs in this paper are those in which the Army places the greatest emphasis. However, it must be recognized that the Army is people; therefore, energy conservation in the Army is a "People Program." The Army Energy Conservation Program started as a program designed to reduce dependence on foreign energy sources. Now, this necessary program is driven by economics. Energy consumption has been reduced in the Army by approximately 30 percent since 1973, but costs have risen to nearly 300 percent during this same period.

AIR FORCE ENERGY SELF-SUFFICIENCY PROGRAMS

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Facility Energy Self-Sufficiency is a concept recently introduced to our Major Commands by the Air Staff. The concept is aimed at ensuring that mission accomplishment is not dependent on potentially unavailable resources.

In its ultimate sense, energy self-sufficiency means total Air Force control and complete security of facility energy, from source to use. Total control and complete security of facility energy would obviously be very expensive and probably unnecessary. But the Air Force has become so reliant on the automatic, the high-speed, the miniaturized, and the computer-controlled, our mission must be at some risk when our facilty energy is at risk. Therefore, the Air Force is attempting to become energy self-sufficient to the greatest degree practical, particularly for critical mission requirements.

From an energy point of view, a "critical mission requirement" does not necessarily equate to those 10-20 buildings which we back up with diesel generators at each base. Those generators cover temporary losses of primary power and will probably remain a requirement even after self-sufficiency is achieved. Rather, we're interested in the synergistic mission effect of long-term primary power outages. Such outages might be caused by political, economic, paramilitary, terrorist, or natural forces, the latter relating to natural energy source depletion. We've never experienced a wide-spread, multi-day power shortage at an Air Force base so it's difficult to imagine what the impact of such an outage might be. But we can hardly imagine zero mission impact after industrial facilities, aircraft maintenance, base supply, civil engineering, security police, training facilities, even dormitories, family housing, commissaries, exchanges, and chapels ha failed to function normally for several weeks. In that sense, all or most of our facilities may be mission critical. Given our energy dependence, a long-term outage would have an impact, and given the dwindling supply of conventional fuels worldwide, such an outage will most certainly occur at some point in time if nothing is done.

Questions are: what will the impact be, what could we live with, when will it occur, and who should do what about it?

We're attempting to answer the first two questions now. Two years ago, Air Force Logistics Command began to study the impact of outages in relation to our six Air Logistics Centers. The impetus came from incidents which caused the entire industrial complex of high tech buildings, buildings far larger than diesel generators could back up, to power down. The incidents illustrated the ease with which the Air Force's critical logistics flow could be interrupted--simply disconnect the base from the commercial overhead grid almost anywhere in the state.

From this study came further considerations of logistics: what else, besides the manufacturing plants themselves, has to operate in order to deliver a given part to a given aircraft or missile? On a routine basis, the answer was, virtually every system and person now in place. Every hour's delay in any link in that chain is an hour's delay in the employment of a weapon system. If the hour occurs at the wrong point in time, our national security could be lost. Therefore, further studies are underway to define the impact of our lack of self-sufficiency and to understand what risks we are willing to live with.

The third question, "when will it occur?", is basicall question for the Department of Energy to answer, though are working with them. The answer involves matters like international agreements, national fuel conversion programs such as the Industrial Fuel Use Act, environmental issues on nuclear and hydroelectric power, natural gas deregulation effects, private sector solar and geothermal developments, the national conservation will and the effects various local, state, and federal statutes have on the resolution of each. Suffice it to say, the answer is far beyond being a military matter. But, from what we know right now, we feel that Air Force self-sufficiency for critical mission facilities must be attained somewhere between the years 2000 and 2035.

The last question, "who should do what about it?", will be of most interest to private industry. Obviously, if there is anything to be done, it will involve resource assessments, consults, design, and, eventually, some major construction.

First of all, we've already taken several steps toward self-sufficiency, though not under that umbrella. Most of our boilers are, or will become, dual fuel capable. Oil-fired boilers can burn natural gas and vice versa, and most of the electrical service inside and outside our bases is set up in loops. These offer a certain amount of energy redundancy which is largely responsible for the energy continuity we've enjoyed to date. Also, military contracts with electrical, gas, and coal utilities guarantee our bases priority on both the supply of the energy and restoration in the event of accidental outages. Moreover, we maintain two to three months' contingency supplies of liquid and solid fuels used by our bases. Each of these conditions has been in effect for several years as routine precautions against supply interruptions.

However, very few of our 130-plus major installations around the world internally generate primary electricity. Our policy has been to generate internally, or purchase over the fence, whichever is cheaper. The ease of long-distance electrical transmission and the relatively high technology involved with fuel-to-electricity conversion have always made it cheaper to purchase electricity over the fence.

Electricity now comprises over 55% of the facility energy we use, and the percentage grows each year as we become more of an electronic Air Force. Yet, electricity is the only major energy form which we don't stockpile. While we stockpile two-three month's contingency supply of fuel to use in our heating systems, we can generate only enough electricity to cover less than ten percent of our normal peacetime requirement, perhaps only five percent of an expanded wartime requirement. It is primarily that gap which energy self-sufficiency is attempting to close.

Closing the gap might seem relatively simple. Just install a nuclear power plant somewhere on the base, harden it and the distribution system, and cut the umbilical cord to the national grid. However, we would need half of the total annual national defense budget for conversion and ten times our current annual utility bill of almost three quarters of a billion dollars for operating and maintaining the system. If the nation's very survival was in imminent danger, perhaps such a commitment would be made. But in the current state of affairs, such a commitment is not realistic, nor is it necessary. Several other realistic options exist and, in some cases, may actually save money.

Perhaps the best looking option for self-sufficiency is cogeneration. We have been approached by several power companies who are interested in building cogenerating peaking plants on our bases. Their interest stems from primary considerations.

First, local or state resistance has prevented them from developing nuclear or hydroelectric plants against projected increases in demand. (After all, it's not just the military which is becoming electronic. The nation as a whole, every industry and homeowner, is tending in that direction.) Air Force bases cause power companies to maintain rather large, mostly idle generating capacity to cover our peaks. It therefore seems natural that we should shoulder some role--in this case, providing land--for them to cover our peaks and divert existing capacity to other, more uniform loads. In exchange, we get priority on plant output which is not only secured within base boundaries but for which fuel could be stockpiled securely.

Second, such an arrangement also offers power companies a way to compensate for pollution restrictions. In California, for instance, no one can build a pollution-producing plant without finding an offsetting reduction of pollution somewhere else. The Air Force, in many cases, may be in a position to offer such offsets.

As a corollary, we've been approached by several municipalities regarding refuse-derived fuel or refuse incineration plants. In this case, both the base and the surrounding municipality have an overwhelming need to stop using existing landfills, either through common sense or by directive. Since the economics are not evaluated against a do-nothing position (they must do something), it appears that combustion of the waste can be an economical disposal method. Depending upon local utility rates, refuse cogeneration may even be economical. If it is, it is a source of electric power which can meet our self-sufficiency criterion of fuel control.

So cogeneration, with various fuel source arrangements, is a very attractive option for self-sufficency.

Renewable energy may also help fill the bill. Solar and wind power are certainly not naturally or politically depletable and are beginning to look economically attractive at certain bases. However, they are also not continuously available without storage systems which double their installation cost. We're trying renewable energy systems at several bases to get an idea of their maintenance and repair costs, but we don't hold much hope that solar or wind power will provide the reliability we'll need for near-term self-sufficiency.

Geothermal energy, on the other hand, can be very reliable. We could also harden the production facility and not worry about too many operational problems once the facility is built. The trouble is, Old Faithful is not a good place to build an Air Force base. We simply don't have electrical grade geothermal resources within most of our base boundaries, though we're still looking.

We're also looking at biomass self-sufficiency. Several of our bases are located in heavily wooded areas which provide enough biomass to totally sustain those bases. We've not made any major conversions because it's more cost-effective to sell the lumber to local paper companies, then purchase power over the fence. But, at some point, the pendulum is bound to swing the other way.

So we can hold these biomass "islands" in our back pocket as an eventual self-sufficiency measure.

Cogeneration has already been mentioned, but a special type of cogenerator, the fuel cell, is also a reasonably attractive technology. The Air Force has gained quite a bit of experience with fuel cells through the space program, and we're now studying terrestrial applications of fuel cells jointly with DOE. Fuel cells do have a drawback in that they must be fed with organic fuels, but again, that fuel can be stockpiled. Moreover, fuel cell energy conversion is quiet, and its infrared signature and pollutants are minimal. Hence, even though it may be too expensive to consider connecting one to every USAF building, fuel cells may be a good option at some of our more forward areas overseas.

Each of the technologies discussed above tends to lead the Air Force toward self-sufficiency. But each has its drawbacks and requires capital to be diverted from other needed defense requirements. By outlining the drawbacks against our self-sufficiency needs, we hope that private industry, recognizing the size of our potential market, might use its collective expertise and imagination to invent or develop technologies which do not have these drawbacks, or at least have drawbacks with which we can live for a longer period. But, capital is a problem equally difficult for us. Again, industry can help, and this is the final point of this paper.

Over the past two-three years, we've been examining a concept called "alternative financing," sometimes also called "third-party contracting." With the various energy tax incentives, interest rates, the Public Utilities Regulatory Policy Act, the National Energy Conservation Policy Act and other laws, it has become financially attractive to venture capital concerns to fund construction of various atypical energy systems, selling power to consumers at favorable rates. PURPA allows this to be done, with certain size limitations. Those limitations, it turns out, may well be within a typical Air Force base's self-sufficiency requirements. If we could interest private entrepreneurs in exploring these possibilities, it could happen that they might profit by providing us dedicated, self-sufficient energy systems without our diverting defense dollars to that purpose.

During our investigations, we've found that alternative financing schemes boil down to three basic categories: conventional fuel plants, mainly cogeneration; renewable energy plants; and shared savings propositions.

The conventional fuel power plant arrangement usually stems from bases and power companies or municipalities sharing a joint need. Typically, the need concerns the power company's difficulty in expanding peaking capacity or the municipality's difficulty in maintaining its landfill. These needs as relate to cogeneration possibilities have already been covered. What wasn't mentioned, however, was that it could just as well be a private entrepreneur who builds and operates these plants instead of a power company or municipality which has little capital for investment. This type of alternative financing scheme is very attractive to the Air Force, both for routine cost-effectiveness and for self-sufficiency.

The second category of alternative financing, renewable energy plants, is also attractive, but we haven't had much luck. The idea here is for a private company to build and operate a solar, wind, or geothermal energy system on or near an Air Force base. The company would base its rates on either their or our assessment of the resource and make rate adjustments if nature fooled us. We have attempted two such contracts already, but when we've gotten into serious negotiations, the companies could not come up with the proper financial backing. They were only testing the concept and found they were already over committed. Therefore, we don't hold much hope for alternatively financed renewable plants. But we're more than willing to listen to serious proposals.

The third category of alternative financing, shared savings plans, seemed attractive at first but has become muddled in practice. The idea of shared savings proposals is that an entrepreneur, well versed in the energy business, will survey a base, locate savings opportunities, then make whatever investments are needed to achieve those savings. The contractor then shares the savings with the base, usually 60% for the contractor, 40% for the base. Such a conservation scheme is attractive from a self-sufficiency standpoint because it tends to lower the overall size of self-sufficiency generating systems. But we've found thus far that firms in this business are mainly interested in measures with 1-5 year payback. We've been able to fund all such measures ourselves through our Energy Conservation Investment Program, a part of the Military Construction Program. There is no reason we, or more correctly, taxpayers, should want to share those energy savings. But we remain very interested in discussing with private industry the funding of 10-20 year payback measures, because it's likely those will never compete with other defense needs.

From this discussion, it should be clear that the Air Force is very interested in alternative financing as one important link in achieving energy self sufficiency.

To summarize, self-sufficiency for Air Force facility energy has become a top priority in the Air Force's energy program. We don't yet have it clearly defined and therefore do not know exactly which road we'll take to achieve it. There are several energy technologies and financing schemes which look attractive, but it is the hope of the Air Force that private industry will provide better answers in the future so that our national defense does not become hostage to the energy whims of the world.

SHARED SAVINGS ENERGY CONSERVATION CONTRACTING BY THE DEPARTMENT OF DEFENSE

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"Shared Savings" is a loosely defined term-of-art which emcompasses any contracting technique for the acquisition of services and equipment by which the contractor's costs are paid out of the savings realized by the client. If the client realizes no savings, the contractor should not get paid.

Since the contractor depends upon his share to meet payroll costs and to repay the loans which financed new equipment, the risk of performance falls heaviest on him.

Shared Savings arrangements may take a variety of forms. The most common are: savings split on a percentage basis (50-50, 30-70 etc.) where the client pays the energy bills and then pays the contractor a percentage of savings; and guaranteed reduction in energy use where the contractor pays the utility and fuel bills and keeps what is saved in excess of the guarantee. Less common are fixed fee arrangements where the contractor guarantees that the fee will always be less than energy bills would be otherwise.

Many different types of companies are using the shared savings approach to market a variety of services, including: engineering services; operating and maintenance services; energy management consultation; and equipment financing. Some companies offer only one of these, some offer all. Few companies do all of their business by shared savings. For most, it is a marketing technique to overcome a customer's perception of an unacceptable risk or the customer's lack of capital.

For the Department of Defense, the most attractive advantages of shared savings contracting for energy conservation are the following:

1. <u>Capital Improvement Without Capital Expense</u>

Most DoD facilities were designed and built in a time of cheap energy. Even with extensive no-cost/low cost energy conservation programs, there remain great savings that can be realized. However, sizeable appropriations ($1.0-$1.5 billion) would probably be required to bring all facilities up to optimum efficiency. Shared savings contracts require the contractor to come up with the necessary capital to make improvements in the client's property.

2. <u>Improved Maintenance Without Added Costs</u>

Not only will a shared savings contractor maintain equipment he has installed, he can be required and will probably wish to assist the maintenance of equipment already on site. In addition, the contractor will be available to provide advice and assistance on planning facility and other long term maintenance. Maintenance performed by the contractor does not also have to be performed by existing staff which are thereby freed to do other work.

3. Guaranteed Immediate Savings

The contractor can meaningfully guarantee savings by carrying an insurance policy or posting a bond. This is clearly something that in-house personnel cannot do. Additionally, the contractor can begin to provide savings in the very first year of the contract. Whereas it takes about 3 years to fund an energy conservation project from *ECIP or get a new appropriation from Congress.

4. Guaranteed Performance

Energy conservation management is a new, complex, and rapidly changing field. Not only must energy managers be well informed, they must be very attentive to the operations and maintenance of their equipment. Private energy conservation companies are able to hire, retain, and motivate the most highly qualified and ambitious people. By requiring a contractor to guarantee his performance promises, the DoD can purchase the best services and equipment at no risk.

5. Energy Cost Stabilization

Cost fluctuations and lack of thoroughly reliable energy management tools have led budget and financial analysts to consider energy an uncontrollable item. An energy conservation services contract can bring this cost under control by guaranteeing a ceiling figure or a percentage reduction. This reduces error in budget figures and the consequent need for either reserve funds or mid-term re-allocations. As an added benefit, dollars are freed by the attraction of

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* DoD's Energy Conservation Investment Program.

private money which in turn reduces costs further. These monies can then be spent elsewhere in DoD Operations and Maintenance budget or be used to offset budget cutbacks or the federal deficit.

These advantages do not come without costs and risks. The most significant seem to be the following disadvantages.

1. <u>It Is New and Different</u>

Because this is a novel field there are dangers that a chosen contractor may not be able to perform as promised. It will take some time and intelligence to learn what is best for DoD and how to recognize and avoid what is threatening. Writing a shared savings contract will be a new task, requiring leadership and personnel. It will have to be integrated into current operations and procedures.

2. <u>Loss of Some $ Savings</u>

Offsetting the financial and performance benefits available under a shared savings contract is the fact that these benefits are purchased out of savings the Department could realize if it could finance and execute the work internally. We have looked closely at the comparative value of these costs and benefits.

3. <u>Policy and Procedural Issues</u>

Two critical policy issues are currently being examined by the Department of Defense in conjunction with other agencies of the executive branch. These issues concern the implications of shared savings contracts on executive and legislative oversight for capital acquisition and the effect of such contracts on tax revenues. Less weighty perhaps, but no less serious, is our concern for finding ways to solicit, let, administer, and account for shared savings contracts under existing procedures.

4. There are Potential Risks

The DoD may be exposed to the chance of injury or loss under a shared savings contract because: the contractor does not perform; there are disputes over base line consumption or the effect of changes in use; or because personnel do not cooperate or actively resist the contractor's efforts.

We have concluded that the advantages outweigh the disadvantages and that the risks can be managed.

We have proposed to DoD that an action research program be undertaken to explore the problems; develop administrative procedures to eliminate the risks; test the concept by letting a set of pilot project contracts; and evaluate the experience to see if it warrants further application.

The Logistics Management Institute (LMI) has prepared and presented to the Office of the Assistant Secretary of Defense for Manpower, Reserve Affairs, and Logistics several briefings on the topic. The full report "Shared Savings Contracting for Reducing Energy Costs of Defense Facilities" and totalling in excess of 50 pages was presented on February 1, 1983. It contained specific guidance on contract goals, contract length, risk management strategies, contractor evaluation criteria, and site selection. The report also suggested guidelines and schedules for a pilot project and discussed in deta such key contracting issues as precedents and authority for shared savings contracts, baseline determination and energy accounting methods, and contractor qualifications. In addition to the approximately 70 references in footnotes, Appendix A contains a bibliography of 35 books and articles for additional reading. Appendix B lists approximately 800 energy service suppliers (broadly defined) with addresses and notes those responding to our survey in Energy User News.

As technical assistance to the development of a set of pilot contracts, LMI has developed and is refining draft contract elements; is assisting the internal discussion on policy issues; and is attempting to develop agreement on administrative procedures to be used in soliciting, awarding, and administering a shared savings energy conservation contract by the Department of Defense.

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Copies of the full LMI report are available from the National Technical Information Service; 5285 Port Royal Road; Springfield, Virginia 22161; 703-487-4650. The report is titled "Shared Savings Contracting for Reducing Energy Costs of Defense Facilities" by George M. Greider and James M. Baker, January 1983.

IMPLEMENTING COST-EFFECTIVE ELECTRIC LOAD-MANAGEMENT PROGRAMS

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1. INTRODUCTION

Since direct load-control programs involve large financial expenditures, it is desirable for utilities to properly schedule the varied activities in implementing these programs.[1] To ensure that the implementation process be cost effective, utilities would like to know in advance what activities will be involved and what the critical issues will be. This paper contains an activity chart that defines the interrelationships of the various activities involved and identifies the associated critical issues. The paper derives most of its material from a research sponsored by the Electric Power Research Institute (EPRI).

The balance of this paper is divided into four sections. Section 2 describes the activites involved a[illegible] their precedence relations. Section 3 discusses the significant general issues in implementing load control, followed by important specific issues in Section 4. Section 5 presents the conclusions.

2. FRAMEWORK TO IMPLEMENT LOAD CONTROL

A number of electric utilities have indicated the need for properly scheduling large-scale load-control programs. Developing a proper schedule requires a road map of what to expect. A generic framework for scheduling the activities is required.

Usually the implementation of load-control programs occurs in stages. Figure 1 shows the five stages that may be generally involved. By breaking each of these stages into detailed activaties, one can obtain a generic activity chart as shown in Figure 2. The horizontal axis represents the progression of time; the vertical axis the different functional groups within the utility company who may be involved with the activities. Thus this activity chart shows the precedence relationship among activities and the different functional groups or departments involved. Using this chart, utilities could find out what they would need to prepare for, should they decide to implement load control.

3. GENERAL ISSUES OF IMPLEMENTING LOAD CONTROL

The following general issues affect the entire implementation process:

3.1 Development Of The Implementation Plan

After ascertaining the desirability of implementing load control, utilities would need to develop a master plan to reach the preliminary goals. It allows one to have an overall picture of what will be entailed during

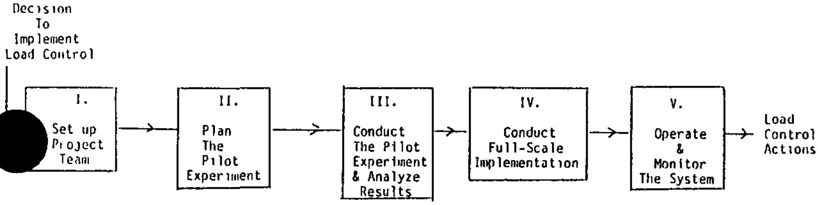


Figure 1: Stages of An Implementation Process for Load Control Programs

FIGURE 2: ACTIVITY CHART FOR IMPLEMENTING LOAD CONTROL

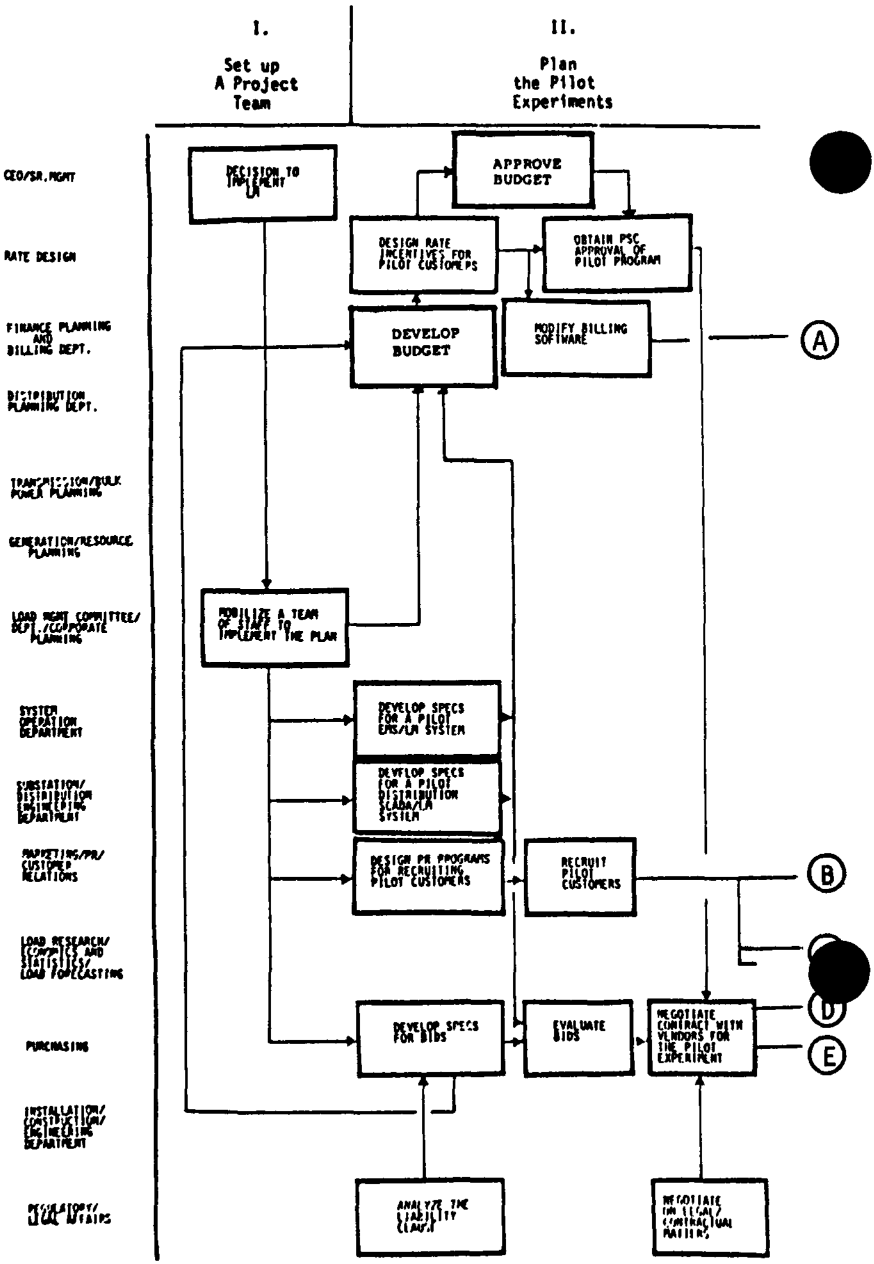


Figure 2 (continued)

III.

Conduct
The Pilot Experiment
& Analyze Results

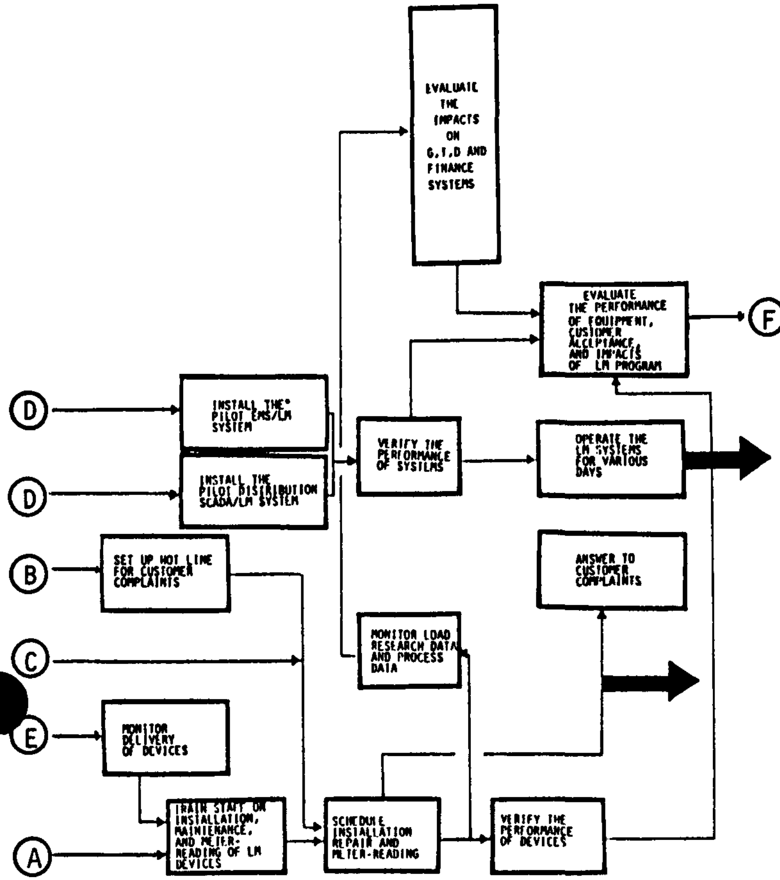


Figure 2 (continued)

IV.

Conduct Full-Scale Implementation

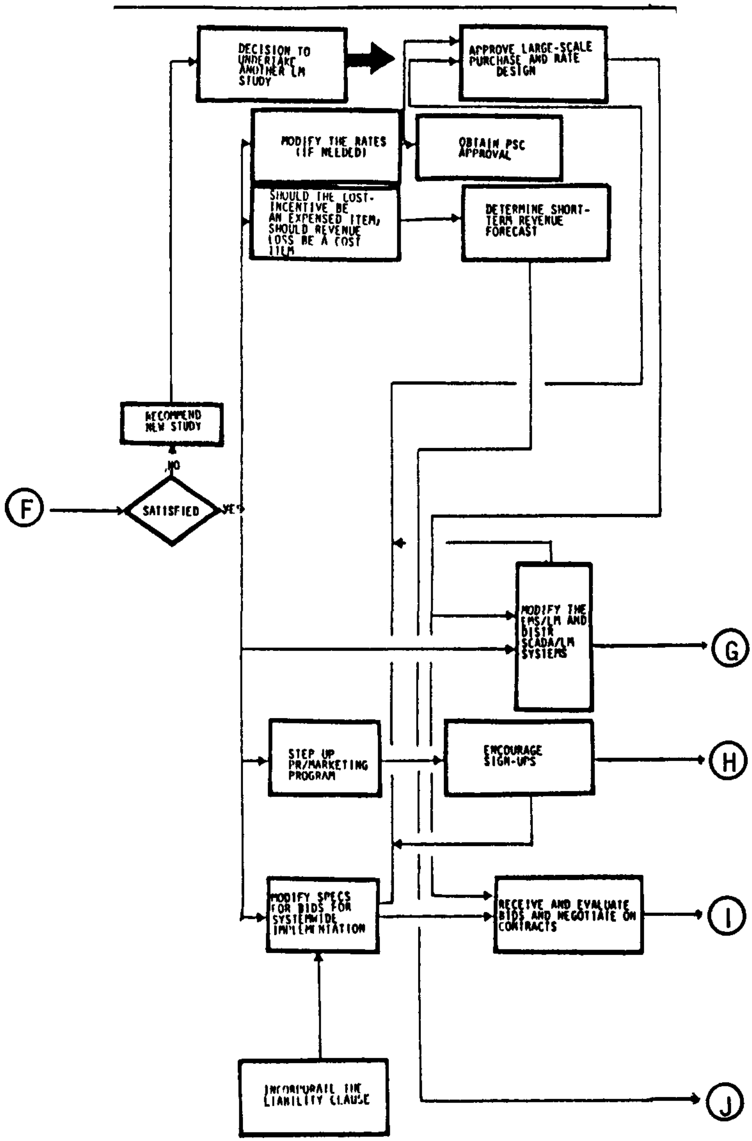
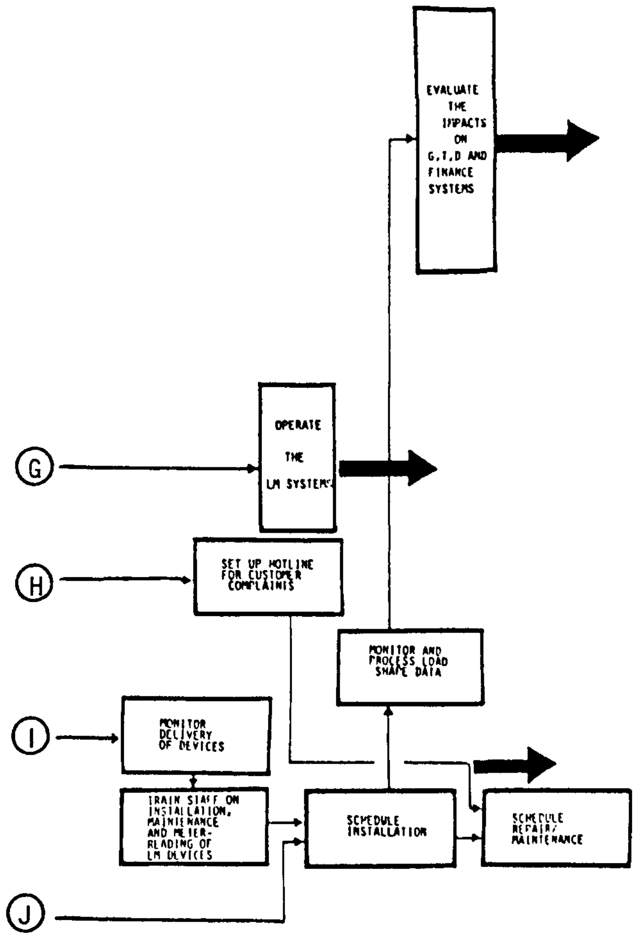


Figure 2 (continued)

V.

Operate
& Monitor
The System



implementation. The plan would range from the development of a project team to the establishment of a maintenance and monitoring system to assure the performance of the many load-control devices. Basically, this plan details the mechanism for engaging the activities in Figure 2.

3.2 Need To Schedule The Implementation Process

Utilities that are ready to implement load control realize that a large expenditure is at stake. Proper scheduling will save tremendous expenses for them.

The fact that varied number of activities and functional groups are involved in implementing load control further accentuates the need for proper scheduling of the activities. Delays of one activity by a functional group, if that activity lies on the critical path of the schedule, will become the bottleneck for the entire project. These delays could easily translate into lost opportunities in realizing savings in fuel costs, energy purchases or power bills. Therefore, there is a need to schedule these activities.

3.3 Uniqueness Of Each Utility

Every utility has its own procedure, policy, and philosophy of "getting things done". Given the differences in corporate goals for load control, system load shapes, generation resources and customer mixes, each utility would select different load-control strategies. As a result, the implementation process would be unique for each utility. It is important to recognize the uniqueness of each utility when implementing load control.

3.4 Time-Phased Approach

Usually a utility implements load control in some time-phased sequence. The staff begins with a screening analysis of the different technologies, then follows with more detailed cost-benefit analyses and equipment testing. Pilot experiments are often conducted next, and if results are indeed favorable, the staff begins to solicit customer participation. Seldom is the initial response so overwhelming that a large percent of the customers join the program immediately.

It should be noted that for manny utilities, the pilot experiments play a pivotal role to system-wide implementation. Usually during the pilot stage, each of the load-control programs is developed and tested individually on its own merits with no regard for coordination. If a utility simply expands the scale of these pilot programs for system-wide implementation and ignores the coordination aspect, the utility may have a number of disjointed load-control programs operating against one another. Therefore, it is important to recognize the importance of the pilot experiments, and that full scale installations are not necessarily expanded pilot programs.

3.5 Organizational Structure

A successful implementation depends heavily on the organizational make-up that is responsbile for the process. As shown in the activity chart in Figure 2, load management cuts across traditional departmental boundaries within a company. The utility management has to percolate the sense of commitment down to each department within the company. An efficient organization that minimizes provincialism and promotes recognition and cooperation would help the implementation. But, regardless of the organization structure, a utility should clearly convey the management's directive, and assign staff on a full-time basis to implement the load-control program.

3.6 Lack Of Data On Implementation Activities

Because of the limited experience in implementing load control, many utilities are concerned about the lack of sufficient data to properly schedule their implementation processes. Utilities could benefit greatly if the industry compiles the data on load-control implementation experience. This compiled data base could serve as a rich information source to help utilities implement load-control programs. Some data is available from U.S. DOE and EPRI demonstrations; still other data may be borrowed or "transferred" from another utility. Several projects are underway at EPRI to provide the tools to make data from utilities transferable between one another and possibly mitigate the need for conducting pilot programs in every case.

4. SPECIFIC ISSUES OF IMPLEMENTING LOAD CONTROL

The following issues relate to specific activities in the activity chart of Figure 2.

4.1 Selecting Load-Control Equipment

While the majority of intended load-shape changes using direct load control can be achieved with a one-way communicating system, utilities could employ a two-way system and incorporate a variety of functions. For instance, not only could a two-way communications system be used for controlling the end-use appliances, but also for distribution-automation functions such as switching distribution feeders and capacitor banks, tampering detection, automatic meter reading, and outage mapping.

As a result, many utilities need to decide whether they should invest in systems that only meet the immediate need of load control, or in systems that can be easily enhanced to execute some distribution-automation functions in the future.[5]

To properly reflect the potential for these functions, they need to consider the following factors in an economic value analysis: the list of functional requirements for load-control and future distribution-automation functions; the rate of technology advancement in equipment hardware; the economic value of each equipment configuration; the financial impacts of having such multi-purpose hardware; the possibility of standardizing procedures for installation, repair and maintenance of the load-control devices; and the possibility of standardizing the communication protocol. Therefore, selecting the proper load-control system becomes a complex issue.

4.2 Developing Functional Specifications For Hardware Interfaces

In implementing load control, utilities have to determine the proper interface among the energy management systems (EMS), distribution supervisory control (SCADA), and load-control systems.[4] The interface involves two dimensions: hardware and software. On the hardware side, in the case of generating utilities, the energy management system's central processing units (CPUs) have to be enhanced to accommodate the functions of a central load-control master. Underutilized CPUs may not need enhancements. On the other hand, energy management system computers that have already reached full capacity may need to add hardware (e.g., memory core) or another computer to accommodate the additional data processing requirements related to load control.

If the EMS is used for transmitting load-control commands to the end-use devices, additional communication channels may be needed. The SCADA remote terminal units (RTUs) may also have to be modified to include additional logic for controlling the various address groups of end-use appliances in each of the operating areas.

The interface with the distribution SCADA system arises if a load-control strategy were to be used for alleviating any expected overload of specific substations. Status and analog data need to be transmitted to the load-control master, which requires an additional communication link between the distribution SCADA and the load-control system.

If a two-way communication system is used also for distibution-automation functions, the distribution SCADA systems at the substations may have to serve as distributed data processors. Additional data channels with faster data rate may have to be added to the distribution SCADA systems.

3 Coordinating With The EMS And Distribution SCADA Systems

When load control is integrated into the power system operations, it should coordinate with the dispatch functions of the EMS and the distribution SCADA systems. This coordination has to be incorporated into the software interface, which includes two categories: system software, and application software.

On the system-software side, additional requirement is placed on the man-machine interface (MMI) software and communication protocols. In most utilities, only a limited number of hours of load control is available so as to minimize customer inconvenience.[6] Therefore, there is a need to keep a running log of the load-control history and update the end-use load shapes as the weather changes. More data need to be processed to serve more functions. More graphic displays are called up for the CRTs. As a result, the system software has to have more data-processing capabilities.

On the application-software side, the interface among the energy management system, load-control master, and the distribution SCADA systems lies in the coordinated scheduling of load control and the central power system dispatch. [4,7] Such interface varies with different utilities, since each utility uses load control for a different purpose. As a result, each utility's system dispatch functions are modified differently to accommodate load control.

A distribution cooperative, billed on a demand rate with a ratchet provision from the power supplier, may invoke its load-control program during system peaks.[2] On the other hand, a generating utility with good baseload generating units may decide to save fuel-burn by shifting more energy use to off-peak periods.[3] In another situation, it may be cheaper to invoke the load control than to purchase interchange energy from neighboring utilities.

Consequently, the power system control center (SCC) operator needs to decide which load-control program to invoke everyday, when to start, when to stop, how long per hour off, and how much the company can still use the remaining allowable hours of control originally contracted with customers.[9] Thus the SCC operator has to schedule the use of load control as a "limited resource" in a manner conceptually similar to the scheduling of hydro storage plants. He wants to schedule load control when load relief is most needed without causing undue inconvenience to customers.

The SCC operator's decision depends on weather, the expected diversified load of end-use sectors, the expected energy payback curves for various candidate control strategies, the status of generating unit availability, the system's incremental generating cost, and the cost of purchased energy. These parameters are dynamic, which make the scheduling problem quite complex.

The scheduling of load control involves close coordination with a number of power system dispatch functions.[7] Those functions include maintenance scheduling, nuclear-refueling scheduling, hydro-thermal scheduling, unit commitment, automatic generation control (AGC) and economic dispatch, interchange scheduling, inadvertent interchange, load forecasting, and pumped-storage hydro operations. The SCC operator has to be especially cautious to properly coordinate the operations of load control and pumped storage, since both try to levelize the daily load shape. Consequently, the EMS application software for these dispatch functions may require modifications to accommodate load control.

If a utility also uses load control in conjunction with distribution system functions, the operator needs to integrate the distribution system status data into the decision for load control.[4,8] For example, if the analog data from the substation RTUs suggest a pending outage at a feeder, the SCC operator, in conjunction with the distribution system dispatchers, can elect to control the end-use load served by another feeder. This switching action allows the latter feeder to also serve the customers at the feeder that has the imminent outage. The SCC operator and distribution dispatchers need to make sure that the energy payback due to load control does not overload the substation transformers. Therefore, a close coordination exists between the scheduling of load control and the operations of both the central dispatch and the distribution network.

4.4 Maintaining Goodwill With Customers

The success of any load-control program is contingent upon customer acceptance. It is imperative for the utility to be highly responsibe to any customer's complaints, concerns, or questions during the pilot stage. Responsiveness is also important during the system-wide implementation stage. A utility cannot afford any negative publicity associated with the load-management program.

The need for maintaining goodwill with customers depends on whether the load-control program is voluntary or not. If it is voluntary, obviously utilities have to give high priority to maintaining the customer goodwill. The public is usually sensitive to negative publicity. The news media generally report "bad" news. Therefore, any adverse reactions from customers could be easily exaggerated to mask the many good points of a load-control program.

If the load-control program is mandatory, maintaining customer goodwill is also important. Since the program is mandatory, not all customer's attitudes will be totally sanguine. If the utility puts enough emphasis on nurturing and maintaining a good customer relationship, then there will be a smaller chance of customer sabotage and tampering of the load-control equipment. Therefore, whether mandatory or voluntary, load-control programs require good customer relationship to ensure success.

A successful implementation of load control depends upon an effective campaign to market to and educate the customers. The public should be fully aware of the pros and cons, objectives, incentives, and procedure of the load-control program. Informing the public at the outset alleviates any apprehension the customer may have about what the utility intends to accomplish.

Effective public relations (PR) and education campaigns lay the groundwork for a bilateral supplier-client relationship. Incorporating load control into the utility operations indicates the utility's transition from a supplier of electricity to an "energy-service" establishment. The customers want to be informed and consulted. As a result, utilities need to monitor the customer's acceptance of various load-control programs, using personal approaches as much as possible.

4.5 Developing Quality Assurance/Quality Check Programs For End-Use Control Devices

Because the end-use load-control equipment reliability is of significant concern, costs associated with malfunctioning units must be factored into all cost-benefit calculations. A good quality-assurance program to detect device malfunctions can help utilities ralize the maximum attainable savings from the load-control system.

Actually, to detect device failures turns out to be a difficult task. There are a variety of failure modes associated with the load-control devices. The failure could be the malfunction of the relay switch itself. It could also be the communication medium or the individual end-use appliance. Various schemes can be designed to detect these malfunctions. However, unless a two-way communication system is used, the information obtained is usually not real-time, and the failure may have gone unnoticed for a long time. Therefore, there is a need to effectively monitor the status of the control device, the communication link, and possibly the end-use appliances a timely basis.

4.6 Developing Optimal Schedule For Installation, Maintenance And Repair

It is important to cost-effectively schedule the available manpower for installing, maintaining and repairing the many end-use devices. These tasks are labor intensive. They involve making appointments with various customers, who may not always be at home to admit the technicians into their premises. Trying to coordinate the window of manpower and device availability with that of customer availability, at the lowest operating cost, becomes a challenging scheduling problem.

The concern for financial impact in scheduling staff for installation is relevant if the utility considers controlling the loads of large commercial or industrial customers. Most of these customers constitute a significant portion of the energy sale. Controlling excessive numbers of these customers may reduce the revenue stream to create a short-term cash flow problem. Thus, the scheduling of these load-control installations could be closely tied to the desired revenue stream.

4.7 Monitoring Dynamic Deviations

When a planner designs a load-control program, he would set certain goals using the available data on end-use load shapes and customer acceptance. As the program begins to unfold, the utility needs to closely monitor the end-use load shape and the rate of customer sign-ups, and then adjust the program accordingly.

This need for continual monitoring and adjusting the load-control programs persists despite a good forecasti analysis in the initial planning stage. No forecasting model has yet been able to accurately predict the future because of the uncertainties in economic conditions, regulatory climates and customer behavior. This phenomenon is especially prevalent in load control, because load control basically involves two aspects of human behavior: shift the customer's energy-usage pattern to affect the load diversity, and encourage customer acceptance. A better understanding, and thus forecast, of the human response to marketing efforts and load control will help reduce the need for closely monitoring the impacts of load control. But this need for monitoring will always persist, and correspondingly the need for modifying the mix of load-management programs.

5. CONCLUSIONS

This paper highlighted an activity chart that showed the precedence relations among the many activities and responsibilities of different functional groups to implement load control. The paper also discussed a number of imporant issues involved when implementing load control. These issues fell into two categories: general and specific. They showed the complexity involved when utilities try to implement load control.

Resolving these issues will take time and experience from the industry. Moreover, some of these issues can best be resolved through the use of some analytical formulations.[10] More research will be needed to effect a complete integrated implementation methodology. A compilation of utility implementation experiences will also be an invaluable data base toward resolving these issues.

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SAMPLE DESIGNS FOR LOAD RESEARCH

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INTRODUCTION

The objectives of load research are to estimate from measurements obtained from a sample of customers, the typical load profile of customer classes. Therefore, load research studies involve sample design, sample selection, load measurement, data reduction, and estimation from the sample data. Given the cost of load research measurements, sample sizes are generally dictated by cost limitations. Thus, load research experiments typically place considerable emphasis on efficient sampling procedures to derive the greatest possible inferential power from the sample data. Once collected, load research data are used for a wide variety of applications in the electric utility industry.

This paper provides a critical overview of current load research sample design, suggestions for improving load research sample design, and a description of a test protocol for evaluating alternatives. In the next section we have focused our overview of current methods to those aspects which are most amenable to change and promise the most gain. Suggestions for improving load research sample design contained in the third section derive both from our critical review and from current statistical research in sample design. Load research is a practical issue in which utilities invest considerable resources. Thus, while alternative methods may be statistically promising, empirical evidence is required. In the final section of this paper we describe a test protocol for the evaluation of load research methods.

CURRENT METHODS

Exhibit 1 provides an overview of some selected load research sample designs. These designs were selected to represent the diversity of current methods and to show common methods. Exhibit 1 also provides a key to our discussions in this section.

Sample Design

In most of the load research sample design reports reviewed to date, the sample design begins with a statement of anticipated precision of estimates from the sample. The estimates for which these statements are made are typically estimates of total or average population kilowatt hour consumption. The key fact of interest here is that kilowatt hour consumption is not the variable of interest in a load research study.

In a load research study the variables of interest are hourly demand values which may or may not be closely related to kilowatt hour consumption. When a utility undertakes a load research study for the first time ever and has no prior experience or prior load research data available, it is a reasonable pragmatic decision to use anticipated precision of estimated kilowatt hour consumption as an approximate guide to the precision of hourly load values which will result from the study. However, after a utility has had some experience with load research activities, they will generally have available to them prior load research data providing a series of hourly demand values for the sampled customers in the prior study. From these data it is possible to obtain estimates of the variability of hourly demand values, which are in fact the true key estimates in load research studies.

An improved procedure, then, would be to use prior load research results to estimate the variability of selected hourly demand values and use the results of the analysis in designing the sample for the current study and in making advance speculation of the precision of these key estimates. While this procedure is statistically valid and many utility companies do have prior load research data available, we find in the literature virtually no reported instances of utilities making use of prior load research data for the design of current load research samples. This is quite surprising

EXHIBIT 1: CHARACTERISTICS OF SELECTED LOAD RESEARCH SAMPLE DESIGNS

Population	Strata Selection		Sample Allocation	Sample Size Variables
	Variables	Method		
Residential(1)	kWh	Rate schedule breakpoints	Neyman(6)	kW-previous load research
Residential(1)	kWh	Dalenius and Hodges(5)	Neyman(6)	kWh
Residential(2)	Water and/or space heating	Billing records	Brewer(7)	kWh
Residential(3)	kWh	Not given	Cochran Ratio(8)	Not given
Residential(3)	kWh	Not given	Not given	Not given
Residential(4)	kWh	Dalenius and Hodges(5)	Neyman(6)	kWh
Small General Service(2)	kW/kWh	Dalenius and Hodges(5)	Neyman(6)	Not given
Small General Service(3)	kWh	Dalenius and Hodges(5)	Neyman(6)	Available recorders
General Service(2)	Space heating	Not given	Not given	Not given
General Service(3)	kWh	Not given	Neyman(6)	Not given
Commercial(4)	kWh	Dalenius and Hodges(5)	Neyman(6)	kWh
Primary(4)	kW	Rate steps	Neyman(6)	kW

(1) These two load research studies are two of six reported in Load Research Manual, Volume 2: Fundamentals of Implementing Load Research Procedures, Argonne National Laboratory, November, 1980. They were selected to represent differences in methods.

(2) These load research studies were selected from twelve studies reported in Report of the Load Research Committee, 1980-1981, Association of Edison Illuminating Companies.

EXHIBIT 1: CHARACTERISTICS OF SELECTED LOAD RESEARCH SAMPLE DESIGNS (Continued)

(3) These load research studies were selected from 12 studies reported in Report of the Load Research Committee, 1979-1980, Association of Edison Illuminating Companies.

(4) The Detroit Edison Company, PURPA Filing, November 1, 1980.

(5) For an explanation of the Dalenius Hodges method, see Load Research Manual Volume 2, Ibid., p. 144-146.

(6) For an explanation of Neyman allocation, see Load Research Manual, Volume 2, Ibid., p. 144.

(7) W. H. Brewer, "What Size Sample?" Applied Statistics in Load Research, Volume III, Association of Edison Illuminating Companies, July 1979, p. 208.

(8) Although this reference was not explicit, we infer that the authors were referring to W.G. Cochran, Sampling Techniques (Second Edition) Wiley & Sons, Inc., 1963, p 167. This, however, does not explain exactly how to do their calculation as additional information on within-stratum variance is required. They may have used kWh.

and, in our opinion, is a significant opportunity for improving the understanding and precision of load research sample designs.

Sample Size

As mentioned previously, sample size is normally determined by cost. There is little of an evaluative nature that can be stated about this. It is simply a fact of life in load research. However, while there is potentially little opportunity to trade off the sample size against precision in load research, it is important to realize that acceptable precision can be gained for the sample size available and whenever this is not the case it may not pay to do the experiments at all. Given the importance of the parameters computed using load research data, it is probably safe to say that estimates with poor reliability could be potentially more damaging than no estimates whatsoever or estimates based on expert judgment rather than on statistical results of low reliability. The key conclusion here is that while sample size is normally constrained by cost, the precision of key estimates is critical in evaluating the overall merit of expending dollars on load research activities.

Sample Allocation

Once stratum boundaries or strata have been selected, the total number of sample units, normally determined on the basis of cost considerations, must be allocated among the strata. The allocation procedure controls the sample size in each stratum and essentially controls the precision of estimates from the stratum. A given stratified sample with a given sample size can produce significantly greater or lesser precise estimates, depending on the appropriateness of the allocation procedure used. In load research practice reviewed to date, most utilities either have used some form of judgmental allocation procedure or have used an allocation procedure referred to as Neyman Optimal Allocation (see Exhibit 1). The Neyman Optimal Allocation provides an estimate with approximately minimum variance for a fixed sample size assuming equivalent costs of data collection in all strata.

Sample Selection and Verification

As noted previously, it is our experience that many utilities design load research samples to provide a certain level of anticipated precision on estimates of total kilowatt hour consumption. We have found instances in the literature where it is recommended that once a sample design is reached and a sample is selected according to the chosen design, the utility then use the selected sample to construct an estimate of total or average kilowatt hour consumption from the sample data. This estimate is then compared with the known population value. If the estimate is within some specified limits of precision, the sample is used for the load research experiment, but if the sample estimate is not within such limits, the sample is discarded and a new sample is drawn. This procedure is repeated until a sample is obtained which provides good correspondence with the known population values. There are two points which must be raised relative to this practice.

First, this practice is referred to in statistics as restricted randomization. That is, the sampling involves selecting not a random sample, but a restricted random sample where the restriction is placed on the correspondence between the sample estimate of total kilowatt hours and the known population value. Sampling variance computations, however, are based on the distribution of all possible estimates which could result from the random sampling. When restricted randomization is used, these equations are no longer valid because not all possible outcomes are allowed. Restricted randomization, in fact, leads to estimates which more precise than indicated by standard sampling variances. It is important that those implementing this procedure recognize what is being done from a statistical standpoint.

A second, and potentially more important point is that the criteria used to discard a sample is based on the correspondence between the sample estimate of the total population kilowatt hours and the true value available in advance of selecting the sample. As we stated earlier, the key estimate of interest in load research is not total kilowatt hour consumption, but is any one of several hourly demand values. It is not clear that rejecting samples which provide poor estimates of kilowatt hour consumption will lead one to the best estimates of hourly loads.

IMPROVING LOAD RESEARCH SAMPLE DESIGN

There are two areas in which we would suggest that there is potential to improve load research sample design. The first area is in enhancing the application of current methods and the second is in application of new statistical procedures.

Enhancement of Current Procedure

Stratified sampling is frequently used in load research to increase the statistical precision of the estimates. Most load research applications are concerned with enhancing the precision of certain estimates of hourly demand which can be used in developing diversified demand customer profiles or computing a number of the parameters. In order to develop a stratification scheme which enhances the precision of one or more hourly load estimates, the stratification scheme ought to eliminate some of the population variance in the hourly load estimate of interest. The best way to do this would be to stratify by hourly load itself.

Unfortunately, the frame for selecting load research samples is generally the customer billing file of the utility company and hourly load data is not typically available in the frame so that it is impossible to use it as a stratification variable. A good second choice is stratification by some other variable which is both available for all members in the frame and is closely correlated to the variable which is being estimated. In practice, most utility companies in selecting load research samples have used the annual or monthly kilowatt hour consumption as a stratification variable. They have selected stratified samples to provide a precise estimate of total kilowatt hour consumption. This is justified by the underlying assumption, supported by limited empirical work, that the correlation between kilowatt demand and kilowatt consumption is sufficiently strong that stratification procedures which improve the precision of estimated kilowatt hour will also improve the precision of estimated hourly loads.

Alternative Sample Designs

In the last several years, survey design research has concentrated on the development of improvements that go beyond the classical stratified sampling methods. The focus of this work has been on improvements in inferential precision without a corresponding increase in sample size. Underlying much of this research is a basic difference in the population model. Finite population models lead to probability-based sampling methods for finite population inferences. Super population models lead to model-dependent sampling methods for predictive inference. The basic difference is the basis for inference. Probability-based sampling methods depend on the randomization in the choice of sample units for inference. Model-dependent sampling methods rely wholly on the model for inference. Recently, some work as been done on model-based sampling methods which attempt to gain the best while avoiding the worst in the other two methods.

Probability-based sampling is the typical method in current use for load research (see Exhibit 1). The value of the load profile for a customer class is thought of as the total over all loads in the group. Load groups are defined by stratification. Within a stratum, sample units are chosen at random with a given probability of selection. These probabilities of selection may depend on a quantitative variable, such as total demand. Inference from the sampled units to the entire group depends on these probabilities. If a regression (ratio) estimator is used, the weight given each observation depends only on its probability of selection. Confidence intervals for the true group value are then derived using the sample selection mechanism as the source of variation.

Model-dependent sampling contrasts probability-based sampling in that the load profile is thought of as a realization of some sample from a super population. Again load groups are defined by stratification. However, the choice of sample units within the load group is defined by the model. The model specifies that instantaneous demand is proportional to total demand, plus an error component. Model-dependent design specifies the sampling of loads, where inclusion in the sample is determined by the total demand. No randomization is used to select sample units. Inference from the sample to the load group depends entirely on the model. The weight given each observation depends on the variance expected under the assumed model.

Probability-based sampling gives design unbiased estimates, but for a fixed level of precision the sample size is often large. Model-dependent sampling uses the model to select the most efficient sample. However, if the model is incorrect, the resulting estimates can be biased. Total error results from both sample error and bias. Thus, if the model is not known to be correct, bias may wipe out the apparent gain in precision.

Model-based sample design is a relatively new survey concept. The idea is to use a model to gain precision while preserving the robustness of probability-based design to model specification. Essentially the model-based approach uses probability-based sampling and robust model-based estimators. Some work has been done on model-based sampling. However, its applicability to load research requires further evaluation.

TEST OF PROGRAM FOR EVALUATING LOAD RESEARCH SAMPLE DESIGNS

The Electric Power Research Institute has recently initiated a study to evaluate current and innovative procedures in load research sample design. In this study a test population will be defined and then alternate load research sample designs will be executed and evaluated based on how well they estimate the parameters of the test population.

Test Population Data Set

In this study, a test data set will be developed and will be used as a test population. The data set will be derived from load research data available from cooperating utility companies. For each account in the test data set two types of information will be available. One, the information which is normally available to the utility company prior to selecting a load research sample, that is such variables as rate class, monthly kilowatt hour sales, monthly peak demand, and if needed, billing method, geographic location, etc. Also for each customer, the hourly loads from a load research study will be available. For this test population, then, it will be possible to compute all the population values of parameters which would normally be estimated from load research activities. This test population can then be used as a tool in evaluating alternate load research sample design procedures.

Test Protocol

Under the test protocol, alternate sample designs will be evaluated. Following the sample selection plan consistent with each design, the samples will be selected from the test population and sample data on hourly loads will be extracted from the test population data file. This will replicate the data which would be collected in the measurement or metering phase. Using this data, error statistics will be computed for each sample design. The error statistics will include mean squared error, empirical bias, average absolute error, maximum absolute error, error at specific times, empirical load factor, confidence interval for the time of peak load, and a scatterplot of empirical errors against population values. On the basis of these error statistics, the alternate sample designs can be compared and evaluated and the results of the study will be made available to utility industry practitioners undertaking load research programs.

CONSERVATION AND LOAD MANAGEMENT: AN ALTERNATIVE TO NEW GENERATION

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ABSTRACT

Carolina Power & Light Company recently cancelled plans for $3.6 billion of new generation and implemented a Conservation and Load Management Program to reduce peak load 1750 megawatts by 1995. This paper discusses the study conducted to develop the $600 million Conservation and Load Management Program and provides an overview of the strategy to accomplish it.

The Company was faced with the need to change its strategic plan for providing customers with reliable and adequate electric service in the 1990's because of an uncertain regulatory environment and unprecedented construction cost escalations. It was no longer feasible to meet the future demand for electricity with traditional sources. A Corporate Policy Committee directed the efforts of outside consultants and 75 employees serving on 15 task forces in a comprehensive six-month study during 1981. Based on this work, the Company implemented an aggressive and diversified conservation and load management strategy which will enable achievement of the benchmark goal of a 16 percent reduction in 1995 peak demand.

The strategy includes 37 programs targeted at a Residential goal of 630 MW, a Commercial goal of 250 MW, and an Industrial goal of 870 MW and a corporate commitment that supports comprehensive planning, research, and marketing efforts.

Conservation and load management is a viable alternative for Carolina Power & Light Company to the construction of new generating units and will help ensure that our customers have a dependable and adequate supply of electric service in the 1990's at a reasonable cost.

INTRODUCTION

In planning for future customer needs for electric service, utilities are evaluating other than the traditional solution of constructing new base load generating plants. While the situation Carolina Power & Light Company faces may be similar to other utilities, there are distinctions that uniquely impact its strategic planning. To fully understand the rationale for CP&L's decision to cancel planned generating units and implement an aggressive Conservation and Load Management Strategy, it is important to have some perspective of the Company and its customers.

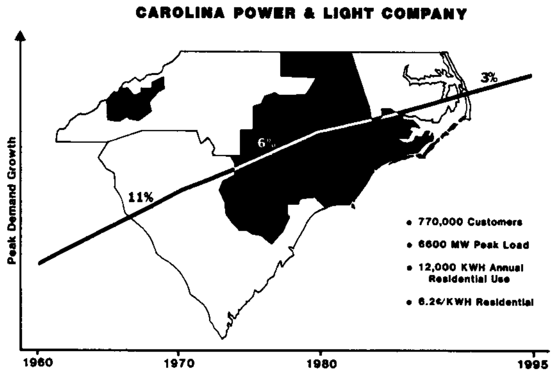


Figure 1

Carolina Power & Light Company provides electric service to approximately 770,000 retail customers in a 30,000 square mile area that includes about half of North Carolina and one-fourth of South Carolina.

An average residential customer used approximately 11,700 kilowatt-hours during 1982 at a price of 6.2 cents. Total revenues for 1982 were $1.5 billion. Summer and winter peak loads are essentially equal at a 6,600 megawatt level. Annual growth in peak demand has changed from a compounded rate of 11 percent during the 1960's to six percent during the 1970's, and is forecast to grow at slightly less than three percent over the next decade. See Figure 1.

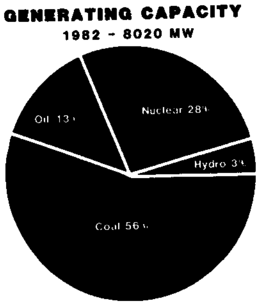


Figure 2

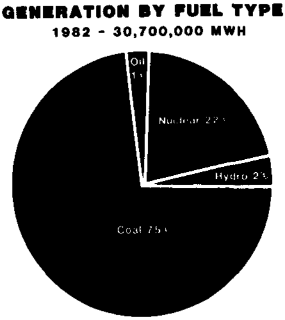
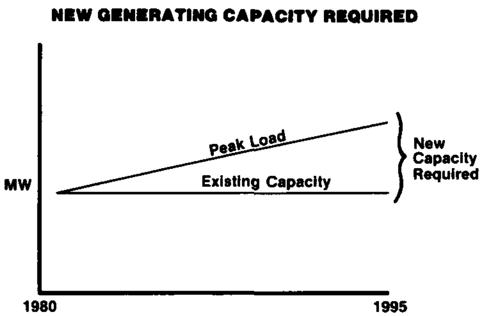


Figure 3

Present generating capacity is 8,020 megawatts with a balance of coal, nuclear, and peaking units as shown in Figure 2. The 1,000 megawatts of oil-fired combustion turbines were installed in the 1960's during rapid growth periods and are used only for peaking purposes. Ninety-seven percent of the 30,700,000 megawatt hours produced during 1982 were generated by coal and nuclear plants resulting in relatively low electric prices compared with other East Coast utilities. See Figure 3.

As the demand for electricity has grown, the traditional approach for CP&L and throughout the industry has been to add new base load generating capacity. See Figure 4. Even with a much lower peak load forecast, it will be necessary for the Company to construct base load generating units between 1983 and 1992 at a cost of nearly $6 billion.



Figure

The cost of new generating capacity has risen dramatically since the mid-1970's, placing a significant financial burden on stockholders and ultimately customers to meet the demand for electricity. For example, the Company added four generating units during the 1970's as shown in Figure 5 at an average cost of $366 per kilowatt. Roxboro 3, a 700 MW coal-fired unit was completed in 1983 at a cost of $166/kW. The two 790 MW Brunswick nuclear units were completed in 1975 and 1977 at costs of $522/kW and $435/kW. The last unit added, Roxboro 4, is a 700 MW coal-fired unit, which was completed in 1980 at a cost of $315/kW.

EXISTING GENERATING UNIT COSTS

UNIT	TYPE	YEAR	$/KW
Roxboro 3	Coal	1973	166
Brunswick 2	Nuclear	1975	522
Brunswick 1	Nuclear	1977	435
Roxboro 4	Coal	1980	315

Figure 5

FUTURE GENERATING UNIT COSTS

UNIT	TYPE	YEAR	$/KW
Mayo 1	Coal	1983	696
Harris 1	Nuclear	1986	2674
Harris 2	Nuclear	1990	2252
Mayo 2	Coal	1992	1213

Figure 6

For comparison, Figure 6 shows the estimated cost of four generating units presently under construction. The 720 MW Mayo units are coal-fired and will cost $696/kW and $1,213/kW. The 900 MW Harris nuclear units will cost $2,674/kW and $2,252/kW. Combined, these four units will cost approximately $1,800/kW, nearly five times the cost of the generating units constructed during the 1970's. This construction program will require the Company to raise in excess of $2 billion over the next three years, which is staggering by historical standards.

So, what are the alternatives to continuing to increase capacity to keep pace with the growing demand for electricity?

STRATEGY PLANNING

During 1981, the Company conducted an intensive six month study of the potential for conservation and load management for reducing peak load. Under the direction of a corporate Conservation and Load Management Policy Committee, the study was completed in December and concluded that a strategy made up of 37 programs to reduce peak load 1750 MW or 16 percent by 1995 was the most reasonable and cost-effective course to pursue. The Strategy, which includes expansion of existing programs and the addition of many new ones, more than doubles the Company's commitment to conservation and load management.

As a result, plans for two nuclear units previously scheduled for completion in the mid-1990's were cancelled.

As shown in Figure 7, the 15-year program includes all three retail customer classes - Residential, Commercial, and Industrial and represents a significant technical and marketing challenge.

CONSERVATION AND LOAD MANAGEMENT GOALS

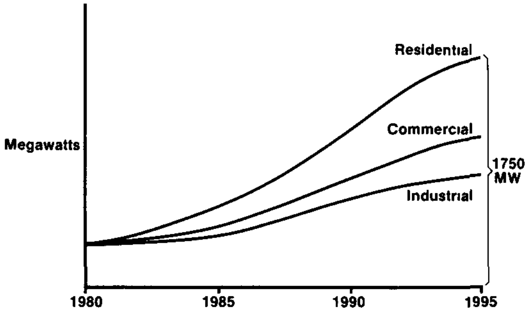


Figure 7

The 1750 MW goal is both advantageous and achievable.

There are four primary advantages. First, this program represents an affordable way for CP&L to provide adequate, reliable, and reasonably priced electricity in the 1990's as it permits a greatly reduced construction program. Second, it helps maintain reasonable reserve margins, which would fall to unacceptable levels without it. Third, as the program builds momentum, it will allow the Company to continue to minimize use of expensive oil-fired peaking units. Fourth, while initial operation impact assessments will require further refinement, they indicate that adequate service reliability will be achieved.

There are five major reasons why the Company is confident that this ambitious goal is achievable. First, we are starting from a solid position and can capitalize on past experience, including the demonstrated market acceptance of some of the most important programs that make up our 1750 MW goal. Over the past several years, CP&L has conducted technical and market research and piloted several residential load management programs successfully. Second, the necessary technology is available. Third, implementation has begun early enough to build our capabilities, to learn, and to make necessary corrections. Fourth, the necessary resources have been committed to achieve the goal. Fifth, a comprehensive marketing program is being developed to raise customers' awareness and gain their commitment to and participation in conservation and load management programs.

In planning the Conservation and Load Management Strategy, the Corporate Policy Committee realized that significant input would be required. Therefore, 15 task forces involving 75 employees were established and outside consultants employed to complement our in-house expertise. The planning study involved three steps as shown in Figure 8.

Each customer sector was analyzed to identify potential opportunities for load reduction. Ideas for programs were developed from Company experience, other utilities' experience, and market research.

Figure 8

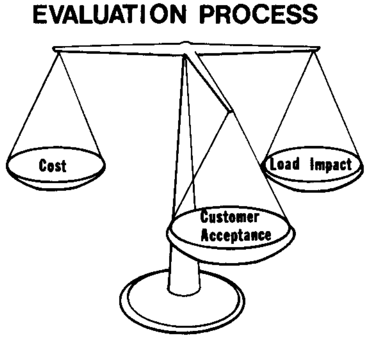


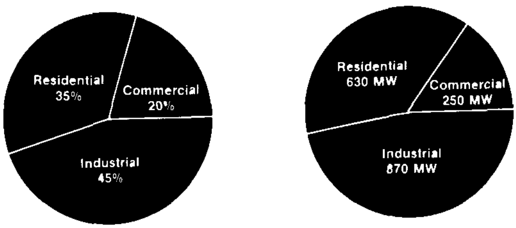
Figure 9

Once feasible ideas were identified, they were evaluated on the bases of load impacts, costs, and customer acceptance. It requires a balance of all three to ensure a high likelihood of success in the market place, as shown in Figure 9.

Finally, the best programs were analyzed as a group to determine the overall impact on system load and energy reductions, impact on system operations, technical feasibility, and regulatory support.

The result of the planning study was a diversified set of 37 programs balanced among our three retail customer sectors and calling for load reduction in each that is proportionate to its projected 1995 peak load. See Figure 10. This balance means that all customers will share equally in this peak load reduction effort and the corresponding benefits. The Conservation and Load Management Strategy is also designed to rely on six types of programs: conservation, cogeneration, time-of-use rates, renewable resource, curtailable rates, and control of residential appliances. This balance among six types ensures that a shortfall in one type of program will not unduly jeopardize the entire strategy.

BALANCED



Peak Load Contribution

Peak Load Reduction

Figure 10

RESIDENTIAL PROGRAMS

To determine potential peak load reduction in the Residential sector, present levels of energy efficiency were examined and reasonable improvements assessed. We found that residential demand could be significantly reduced by improving home insulation and installing high efficiency heating and cooling equipment. Knowing that a very high percentage of our residential customers have electric water heating, we also concentrated on ideas to shift that load to off-peak periods.

In the assessment of Residential load reduction, we examined devices, equipment, rates, and incentive plans designed to improve efficiency or shift usage off peak. Special attention was given to designing programs that would be affordable and acceptable to the customer.

RESIDENTIAL

EFFICIENT STRUCTURES	EFFICIENT APPLIANCES	APPLIANCE CONTROL	CONSUMER BEHAVIOR
• Audits	• Heat Pump	• Air Conditioner Control	• Time of Use Rates
• Low Interest Loans	• Air Conditioner	• Water Heater Control	• Improved Billing Information
• Common Sense	• Solar Water Heater	• Strip Heat on Heat Pumps	• Community Energy Watch
• Passive Solar	• Other Major Appliances		

Figure 11

From this analysis, a set of 14 programs was adopted based on a strategy of extensive and direct contact with customers to reach a goal of 630 MW load reduction in 1995. The programs are divided into four categories - Efficient Structures, Efficient Appliances, Appliance Control, and Consumer Behavior. See Figure 11. The residential programs are in various stages of readiness for implementation. Some have already been introduced systemwide, while others are being fine-tuned.

Our overall strategy includes a customer information program emphasing the need for conservation and load management and its benefits. Distribution of the 14 programs will be made through the decision makers and those influencing the ultimate use of electricity.

COMMERCIAL PROGRAMS

Even though the Company has been promoting conservation activities for several years, only a small effort has been directed to this group of customers. Much needs to be learned about their energy use habits and characteristics. Within the Commercial sector, three types of customers account for more than 70 percent of total energy sales: Trade, Services, and Government. Conservation and load management program implementation will initially be directed at these major groups.

In developing the programs and the overall strategy for this sector, we have built on Company expertise and the experience of other utilities. Eleven specific programs were identified that will result in a 1995 peak load reduction of 250 MW. See Figure 12.

COMMERCIAL

STRUCTURES	CURTAILABLE	OTHER
• Audits	• Cooperatives	• Time-of-Use Rates
• Lighting	• Emergency Generators	• Thermal Storage
• New Buildings		• Contract Demand Reduction
• Company Buildings		• Agricultural Load Reduction
• Chain Operations		

Figure 12

The Commercial sector strategy targets the thermal integrity of structures and end-use efficiencies, potential curtailable loads, and the use of rate designs to achieve load shifts to off-peak periods. Like the residential strategy, these programs key on customer contact. It is essential that the Company acquire a better understanding of customer-side economics and end-use data for effective marketing of these programs. Thus, implementation will be deliberate and less rapid than in the Residential sector.

INDUSTRIAL PROGRAMS

Within the Industrial sector, three major industries account for 55 percent of the total demand and 66 percent of the energy sales: Textile, Chemical, and Paper Manufacturing.

In developing the Industrial sector strategy and programs, we used ideas from many sources within the Company, researched other utility experience, and conducted more than 40 large customer in-person interviews. Twelve programs were developed that are projected to deliver a 1995 peak load reduction of 870 MW as shown in Figure 13.

INDUSTRIAL

Figure 13

ASSISTANCE	POWER PRODUCTION	CURTAILABLE	OTHER
• Audits	• Cogeneration	• Process Loads	• Time-of-Use Rates
• Education	• Small Hydro	• Cooperatives	• Thermal Storage
• New Plants		• Emergency Generators	
• Efficient Heating & Cooling		• Plant Rescheduling	

Left unmanaged, projections indicate that our industrial load would more than double by 1995. However, with these programs, the load still will show growth, but at a somewhat reduced rate. Implementation of these programs has begun with building our resources and expertise in cogeneration, audits, and technical assistance to provide a resource for customers. To achieve the 870 MW goal, areas of greatest potential will be targeted first. It is expected that the smaller customers will follow the leadership of the larger industries. Our strategy includes flexibility in negotiations and a sharing of the total benefits of load reductions.

IMPLEMENTATION

The Company has adopted a three phase implementation process: Research and Development, Pilot Programs, and then Full-Scale Implementation. In the first phase, laboratory and/or field tests are conducted to determine load reduction, technical feasibibility, potential customer acceptance, and program costs. In the second phase, the program ideas are piloted in a limited area to determine the best marketing approach and work out the necessary procedures. Third, we implement full-scale by expanding the program in a controlled manner to the remainder of our service area.

We recognize that successful implementation of this Conservation and Load Management Strategy will require a substantial commitment of resources. Therefore, in March 1982, the Company formed a new department with a mission to plan, implement, and monitor cost-effective programs. See Figures 14 and 15.

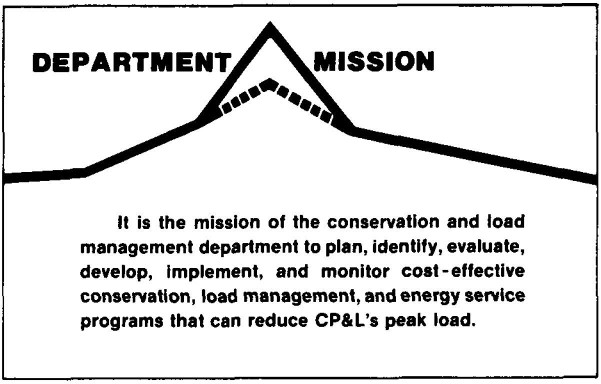


Figure 14

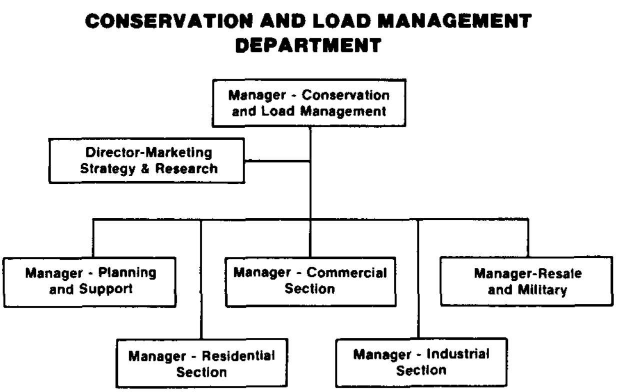


Figure 15

The Department is functionally organized by customer sectors to ensure accountability for the 1750 MW goal. The Planning & Support Section serves all four customer sectors by providing overall planning and program evaluation, and by conducting technical research. The Marketing Strategy and Research team guides the development of an overall marketing strategy. The staffing level for the department is presently 71 with much of the work conducted along the matrix management concept that interfaces with field operations which has primary responsibility for customer contact.

COSTS

Carolina Power & Light Company intensified and formalized its conservation and load management efforts due to the high cost of new generating units and its belief that future customer needs would be better met through such a program. The cost of this program, excluding $165 million in periodic customer incentives, translates to $250/kW compared to $2,000/kW for new generation in the 1990's.

SUMMARY

In summary, Carolina Power & Light Company's Conservation and Load Mangement Strategy is advantageous for several reasons. It represents an affordable way for the Company to provide electricity in the 1990's. The lower costs of the strategy as compared to the cost of new generating units will result in more favorable prices for our customers.

The program should allow the Company to maintain an acceptable level of service reliability and help us continue low-level use of expensive oil-fired peak capacity. This program, designed as a cooperative effort between the Company and its customers, should permit sound economic growth in Carolina Power & Light Company's service area with an adequate, reliable, and reasonably priced supply of electricity.

CONTRIBUTIONS OF ROBOTICS TO INDUSTRIAL PRODUCTIVITY IMPROVEMENT

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ABSTRACT

In efforts to increase productivity, reduce waste and improve quality, companies in the United States and overseas have begun to increase the use of robots in manufacturing plants. The automotive industry has led the transition in the U.S. using 40 percent of the over 7,000 industrial robots in our country.

This paper presents a compilation and analysis of productivity data reported for a variety of robot installations. Although the reported productivity gains for robots are very impressive, more rigorous documentation of productivity improvements is required by industry for future analyses of robot systems and manufacturing plants.

INTRODUCTION

In the past few years there has been a marked increase in the national awareness of robotics. The public adulation of R2D2 and C3PO of the movie "Star Wars" has been followed by extensive press coverage of the introduction of robots into industry. Behind the glow of the national limelight there is indeed a phenomenon taking place which will greatly influence the way products are manufactured. Significant changes in productivity and energy usage patterns will accompany this trend toward the use of robotics.

The main reason for the introduction of robots into industry is that the economics of manufacturing is changing so that the use of robots is becoming profitable. The cost of the microcomputers used in robots has dropped dramatically, while the microcomputers have become smaller in size. In the meantime, the cost of labor has increased as wages have risen over the years in response to inflationary pressures.

Another push toward the use of robots has come from foreign competition, especially Japanese products. Part of the reputation for quality in Japanese automobiles and electronics is attributable to the use of robots. American manufacturers are now introducing robots into their production lines, not only to cut costs but to improve quality and consistency in operations such as spot welding and inspection.

One frequent question that is posed in discussions of factory automation is "What is a robot?" This was addressed in 1979 by the Robot Institute of America (RIA), a national trade association of robotics manufacturers, distributors and users with the following results: "A robot is a reprogrammable, multi-functional manipulator designed to move materials, parts, tools or specialized devices through variable programmed motions in the performance of a variety of tasks." The point is that robots are flexible, they will consistently perform a sequence of mechanical motions over and over again, and they can be reprogrammed to perform several different tasks with a minimal amount of retooling.

There is an impetus toward robots because they are often the most economical way to produce medium size runs of parts. For very large volumes of parts, where millions of identical pieces are cranked out year after year, hard automation with special tooling is the answer, rather than robotics. On the other hand, quantities of one or two of a kind are best handled by manual fabrication. In intermediate size lots, however, robots offer flexibility, such as for products which need individual configurations for various markets. The robot can merely be reprogrammed in going from one run to the next, instead of scrapping tooling.

Because of the factors described above, robots will play an increasing role in the coming years. The penetration of industry by robots is important to manufacturers, labor, electric utilities, and legislators. Science Management Corporation has analyzed the effects of robots on utility electrical loads and has examined the potential uses of robots in hazardous environments. The study which is reported in this paper is an examination of the effects of robots on productivity.

APPLICATIONS OF ROBOTS

Robots are the ideal solution for many factory automation problems. With current capabilities, robots are usually justified for batch operations ranging from 200 to 20,000 parts per year. Smaller jobs are usually best handled manually or by dedicated numerically controlled machines. Larger jobs are handled more cost effectively by fixed automation. However, with the increasing capabilities of robots, the useful range is sure to expand.

The inital introduction of robots into the work force has included the following four general areas:

- o Hazardous or uncomfortable working conditions (e.g., process furnaces, die casting, spray painting, hot forging, asbestos, mercury)
- o Repetitive tasks (e.g., packaging, palletizing)
- o Difficult handling (e.g., delicate instruments, awkward and heavy workpiece manipulation)
- o Multishift operation resulting in faster payback (e.g., injection molding, spot welding)

Each of these categories suggests several specific applications. Today's industrial robots have been applied to a variety of such tasks, including:

- o Materials handling
- o Machine loading
- o Spot and arc welding
- o Spray painting
- o Machining
- o Assembly
- o Inspection

Of these applications, the first three are the most common. The other applications will become more prevalent as advances continue in sensor technology and computer control (51).

PRODUCTIVITY EFFECTS OF ROBOTS

A broad-based definition of productivity for an organization is presented by Sumanth (52):

> Productivity is the measure of how well resources are brought together in organizations and utilized for accomplishing a set of results.

More specifically, Sumanth discusses three types of productivity measurements which were orginally defined by Kendrick and Creamer: partial productivity, total productivity and total factor productivity. Surveys have revealed that, of the three, partial productivity measures are most commonly used by industry. Partial productivity is defined as the ratio of gross or net output to one class of input, such as the number of parts per man-hour. This is the measure used in this paper. In terms of this definition, we have analyzed the percentage increase in productivity resulting from the use of robots in each application. In this paper, we will present a comparison of the percentage increase for various types of applications.

The data on productivity increases for various applications is shown in Table 1. Note the very large spread in productivity increases reported -- ranging from 13% to 1300%. As can be noted from the list of references, the results were mainly reported in robotics journals and in manufacturers' literature over the past [illegible] years. The sources of data may have resulted in some optimistic b[illegible] in the productivity increases reported, since robot manufacturers tend to cite their best results, as do authors preparing technical papers. On the other hand, because of competitive factors, manufacturers are not disclosing some of the data on successful implementation of robots. Because of the nature of the data displayed in Table 1, it offers some indications of productivity improvements in industry, but it cannot be considered as exhaustive. The limitations of the data constrained this study to simple techniques, namely averaging the productivity increase percentages for various applications and reporting the results, which are also shown in Table 1. The available data on the applications were insufficiently detailed to calculate other productivity indices, such as dollars of product value per manhour or "total productivity" in terms of capital and labor. Nevertheless, the productivity data exhibited allow us to make some useful observations.

TABLE 1

COMPARISON OF PRODUCTIVITY INCREASES

APPLICATION	NUMBER OF CASES	RANGE OF PRODUCTIVITY INCREASES	AVERAGE INCREASE
Inspection	3	33% to 1300%	544%
Shot Peening	1	300%	300%
Machining	2	200% to 300%	250%
Chemical Cleaning	2	100% to 400%	250%
Machine Loading	10	13% to 776%	235%
Palletizing	4	57% to 400%	214%
Deburring	1	200%	200%
Forging	6	30% to 290%	166%
Welding	13	24% to 400%	162%
Riveting	1	100%	100%
Casting	11	16% to 175%	93%
Painting	1	32%	32%
Total	55	13% to 1300%	193%

NOTE: Data extracted from references 1-50.

Table 1 lists the applications in order of percentage increase in productivity. Because of the small sample sizes of the various applications and the large spread of productivity increase values, the order shown represents only a rough indication of which applications give the greatest productivity increases. Note that the largest average increase reported is for inspection applications. This is not surprising, since 100% inspection of parts is very labor intensive. The next applications in the list are shot peening, machining and chemical cleaning. These are applications where the repeatability achieved by using robots provides high quality at a faster production rate. Machine loading is next on the list; often one heavy duty robot can lift a load into place which would otherwise require two or more people. Further down the table, we see that welding is the application most cited in the literature. This is because many of the early applications involved spot welding. Spot welding is an unpleasant job and people tend to miss welds. Note that painting is at the bottom of the list in terms of percentage improvement in productivity. This reflects the fact that spray painting robots are justified in terms of quality improvement, paint savings, and reduction of exposure to paint fumes, rather than on the basis of productivity improvement. The overall average increase in productivity for the 55 cases shown in 193%.

ENERGY EFFECTS OF THE USE OF ROBOTS

The use of robots may cause significant increases or decreases in the use of energy within a given manufacturing plant. Robots use electricity, and, therefore, electrical loads might be expected to increase during the time they are operating. The electrical load is spread over a 24-hour period if the robots work all three shifts. Robots do not require heating or lighting for their comfort, and some types of energy usage could, therefore, be expected to decrease. We examined these various factors in another study for EPRI. This is the subject of another paper presented at this conference.

TRENDS IN THE USE OF ROBOTS

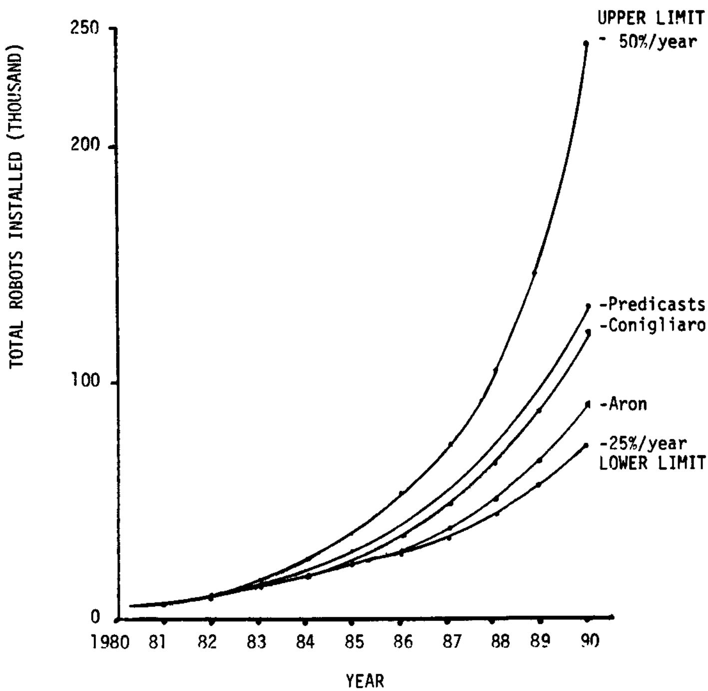
Most analysts who have projected the growth of the robot industry in the United States have assumed exponential curves as shown in Figure 1. Probably the most widely quoted estimate is the one developed by Laura Conigliaro of Prudential-Bache (53), which has a 35.4% per year growth rate. Predicasts (54) predicts a slightly higher growth rate and Aron (55) predicts a slightly lower one. Science Management Corporation selected an upper bound estimate of 50% and a lower bound estimate of 25% which are respectively above and below the other three curves. We chose these limits to provide sufficient margin around the generally accepted projections. These upper and lower bound estimates form the basis for projecting usage of electricity by robots when viewed in the light of trends in robot development.

Most analysts have concluded that assembly robots are the wave of the future. In our interview with Joseph Engelberger, founder of Unimation, he voiced the same opinion. Assembly applications seem especially promising because of the large number of highly paid workers doing repetitive assembly throughout industry. Advances in vision and touch sensor development for robots can quickly lead to economic justification of assembly applications. Likewise, more sophisticated robots will be able to take over many inspection applications. As new robot applications develop, some earlier robot applications will see their markets saturated. This is especiall true for spot welding, which has already had a signific penetration by robots. Arc welding, on the other hand, sho continue to grow for many years. As robot designs become more sophisticated, there will be increased use of lightweight materials and more energy efficient drive systems. More small electric robots will be developed to handle the surge in assembly applications.

FIGURE 1

FORECASTS OF GROWTH

OF U.S. ROBOTS INSTALLED



OBSTACLES TO ROBOTICS

The most obvious obstacle to increased use of robots is the resistance of some unions to increased automation. A large number of minimal skilled laborers can be replaced by a small number of robots. Retraining of some of these people for new positions, requiring more quantitative or analytical skills, will be difficult because of the low level of trainability (literacy, age and motivational factors) among a large percentage of this sector of the work force. However, some unions, such as the United Auto Workers, have viewed robots as a means of saving the industry, thus saving jobs. Their efforts have been directed to training and other guarantees. Also, in jobs with high accident and health risks (e.g., uranium mining, asbestos factories) the resistance to change is often mitigated (51).

Resistance from management often exceeds resistance from labor. Management's concerns include the short-term impact of a new installation on profitability, requirements to learn about a new technology (i.e., resistance to change) and the work required to justify large capital expenditures. Thus, successful implementation of robots requires commitment from top management down to the factory floor.

Another obstacle to the most efficient use of robots is the anthropomorphization of the manufacturing process. Most manufacturing processes have been designed to facilitate operation by a human. However, human capabilities, orientations and methods may not be the most effective way of performing an assembly task, for example. Therefore, creative efforts by engineers will be required to review manufacturing methods, and then to develop robots to take advantage of the most efficient methods, rather than constrain robot designs by human limitations.

CONCLUSIONS

The increased use of robots in industry will have important implications for improvement in productivity. This study revealed that productivity data for robots are scarce and not well defined. More rigorous definition of productivity and documentation of results will assist in evaluating the true productivity impact of robot systems. Additional data are needed to correlate the productivity improvement from the robot system to that of the overall facility.

ACKNOWLEDGEMENTS

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THE TRUE POTENTIAL OF DIRECT DIGITAL CONTROLS

William J. Curran
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EVERYONE IS TALKING ABOUT "DDC"

As applied to HVAC equipment and other building systems, Direct Digital Controls has been talked about, promoted and supported to an ever increasing degree over the past few years. The extent to which DDC has been implemented, however, is very minimal.

Quite often the main system components such as OSA and RA dampers, main chilled and hot water control valves and sometimes fan inlet vanes are the prime candidates for DDC. The terminal units, however, are still being controlled through the use of conventional thermostats which limit the potential of a truc DDC system.

WHAT'S THE JUSTIFICATION FOR COMPUTERIZED CONTROL SYSTEMS?

Over the past 10 years computerized building control systems have gone through various modes of justification. First, they were justified as simply a replacement of hardwired manual control panels. Ease of building operation was the main concern. System features included basic start/stop functions, along with the monitoring of many of the building parameters. Remote reset capabilities also grew as it provided the system operator with a means of adjusting not only the main system parameters but also those of the individual zones. These systems often had over 1000 points.

When the justification changed from building control to energy management, energy savings became the sole justification for the control of mechanical systems and as a result, the number of monitoring points were greatly reduced.

At the current time it is not common to see the I/O summary for a 300,000 square foot building limited to less than 250 total points. Optimal Start, Duty Cycling and Demand Control can all operate within these restraints so additional monitoring points can not be justified on an energy saving basis.

With the typical installed cost of an EMCS budgeted at between $750 and $1,000 per point, this 250 point system will run in the neighborhood of $220,000. As the application of this system is aimed primarily at energy management, a complete Automatic Temperature Control (ATC) system is also required in addition to the EMCS. The ATC system could run approximately $200,000 making the combined system cost approach a half million.

WHAT HAPPENED TO THE 1000 POINT SYSTEMS?

Ten years ago the trend in the automation industry was to monitor the building and building systems for the purpose of improving overall performance and reducing maintenance costs. Energy management was not the prime concern and systems could be justified based on operational benefits.

Of course the cost of Systems at $1000 per point would mean an investment of $1 million for the automation system and when added to the $250,000 ATC cost, this additional $750,000 has become very hard to justify irregardless of the operational benefits it affords.

SO WHAT'S DDC ACTUALLY GOING TO DO FOR YOU?

- It controls more accurately so it wastes less energy.
- It has less moving parts so it requires less maintenance.
- It doesn't drift out of calibration so it needs less service.
- Its simplicity can remove the traditional ATC mystique.

SO WHY ARE WE STILL USING ALL THOSE THERMOSTATS?

There seems to be total agreement throughout the industry that DDC is the way to go, so what is really happening? Let's look again at our typical 300,000 square foot building. It probably has 4 large Variable Air Volume (VAV) fan systems and 150 VAV boxes. Each fan system has 3 control loops; one for the OSA dampers, one to control the fan's CFM and a third to control the supply air temperature.

Three PID control loops per system times 4 systems for a total of 12 control loops out of the 162 required to operate the entire building.

If DDC is so good, then why are we using it on only 7% of the building? What's happening to the other 93% of the building's control requirements? They are being handled with old fashioned pneumatic thermostats. The ones with single or dual setpoints and maybe even locking covers. You know, those covers designed to prevent indiscriminate tampering. The ones that everyone has a key to.

DDC BENEFITS THE CONTROL OF THE ZONES TOO!

If the control requirement of the individual zones was not a consideration, the traditional controls companies would not have spent the recent time and money to upgrade the old thermostats with deadband controls and locking covers.

With DDC applied to the zones, the control center takes full responsibility for the zone conditions and provides:

1. Remote Setpoint Control

2. True Deadband Control

3. Complete Performance Monitoring

4. Computer Aided Troubleshooting

With DDC applied to the zones, varying setpoints can be automatically downloaded to each zone which not only saves energy, but also helps to maintain total system balance. It prevents over cooling and over heating and contributes to a more liveable environment.

With DDC applied to the zones, the ability to vary the space temperature setpoints in accordance with building loads and occupancy schedules provides energy savings in excess of those available through even the most advanced thermostats.

With DDC applied to the zones, the true ongoing performance can be viewed as every controlled component can be continuously monitored by the computer. If a reheat valve sticks open, this operational and energy deficiency is easily detected. And, as the central computer knows the actual heating and cooling load for every zone, it can further optimize performance through more accurate applications of supply air temperature and CFM reset.

With DDC applied to the zones, the various components of the HVAC system may be exercised on an independent basis to aid in the isolation of defective system components. For example, if the temperature of one zone drifts above the normal limits, the system operator may command the full opening and closing of the VAV box independently of the operation of the reheat valve. By then observing the effect on the space temperature, the working component of the terminal unit may be isolated from the non-working one. In the event that the reheat valve is stuck open, a temporary change to the hot water supply temperature control algorithm could bring the zone back into control until the valve repair is made.

NOW, WHAT ABOUT THE COST?

With the ever decreasing cost of micro-electronics equipment, stand-alone microprocessor based control units can be installed at less than [illegible] per point plus the cost of wiring. As these units are normally much smaller and located closer to the sensors, the wiring costs are greatly reduced. Less than $100 per point is often the case. Thus, the cost per point can be as low as $150 compared to the 750 to 1000 dollar costs discussed above.

Now, looking again at our typical 300,000 square foot building, each of the 150 VAV boxes would be monitored through the use of one space temperature sensor and two (2) analog output points for the control of the VAV box and reheat coil. The system could also monitor the position of both controlled components in the form of analog input points, making the total number of points per zone equal to 5.

With 150 zones, each with 5 points and assuming that the fan systems could be monitored and controlled with 16 points each, the total monitoring system would include approximately 814 points. At an installed price of $122,100 for the field and with a cost of even $200,000 for the central computer and software, we now have the ability to provide a system far superior to the separate EMCS/ATC configuration for $322,100. This is roughly $100,000 less than the system discussed previously and also provides increased monitoring through over 800 valuable field points.

THE PERSONAL COMPUTER AS AN ENERGY MANAGEMENT SYSTEM

Daniel P. Cronin
President
Business and Industrial Computer Co.

I. SYSTEM HISTORY

The company is a producer of a full line digital computer based data acquisition and control system. The concept grew out of a need for computer assisted testing and a general purpose facilities controller to perform such functions as power demand control, time of day control, HVAC control, etc.

Existing systems that performed these tasks were expensive (based on $50,000 computers), single tasked, and packaged so as to restrict user modification and development. It would be necessary, therefore, to buy multiple computers, each for a given task. The data acquisition systems also had the problem of being either expensive (IBM Series 1) but capable of generating reports and storing data for use on the mainframe, or inexpensive but stored data on adding machine tape. The former restricted the system development by requiring the vendor to do all modifications and needing The Data Processing department to do any data manipulation by the mainframe. Both of these required significant justification and cost and so restricted the use of "what if" investigations and the development of reports to be used for only a short time or on an experimental basis.

The applications being considered were:

1. Monitor process equipment being considered for purchase to compare efficiencies.

2. Monitor process equipment that could perform the same task in order to determine the optimum equipment.

3. Monitor large energy users to be sure they are operating under control and at an exceptable efficiency.

4. Monitor typical process equipment to develop energy use standards for each product type or group. This data is used in conjunction with the production totals to generate an expected energy use. This is compared to actual energy consumption to determine if the process is under control.

5. To seperate the consumption of departments to allow energy costs to be charged directly to them to motivate better control.

6. To control HVAC equipment according to time, temperature, enthalpy, etc.

7. To turn off unnecessary electrical equipment during peak load periods to reduce power costs.

8. Conduct studies to determine the potential for energy savings projects.

All of these tasks had the characteristic of not requiring high frequency attention. This meant that from a technical stand point one computer would be fast enough to do all of them simultaneously.

What was needed was a general purpose data acquisition and control system that would:

1.Read an analog signal
   a.Temperatures
   b.Recorder outputs from general instruments
   c.Transducers

2.Read any pulse signal
   a.Fluid meter integrators
   b.Production count

3.Store data on signal or by time.
   a.Releived the need for personnel to "hang around" waiting for a production cycle to end.
   b.Provided intermediate data

4. Store data so that it could be tabulated, manipulated and graphed with a minimum of error, time and effort.

5. Provide remote relay and proportional control.
   a. Load management
   b. Time of day control
   c. Enthalpy control
   d. Process control in response to acquired information.
   e. Warning light for operator intervention to provide explanatory fault code.

6. Provide documentation and access to allow the non-professional user to develop his own custom applications.

The data acquisition functions of this system would provide an increase in efficiency in the engineering staff because it would allow the operation of an experiment without the constant attention of technical staff. It would allow the gathering of data from process cycles that run for over the 8 hours that staff people are generally available. It would allow the gathering of sufficient data to provide a statistical population more quickly since it operates continuosly. It would allow faster, more complete and better quality reports by reducing the amount of data handling in its manipulation and display.

The control functions would allow optimization of process and facility equipment as well as perform such standard tasks as power demand control.

II SYSTEM CONCEPT

The system is designed around the Apple personal computer. This allows complete control and development capabilites since it was designed and documentented for the use of the general public. The Apple has an electronic spread sheet and graphics package which accepts the dat directly from our data acquisition and control system. This feature allows the data to be turned every imaginable way with a few simple keystrokes and then allows direct printing of tables and graphs.

External hardware was developed t0:

1. Provide a capcity of over 1500 points.
2. Reads:
   a. Analog signals
   b. Pulse counts (totalizer/integrator)
   c. On/off status
3. Provides:
   a. On/off control
   b. Proportinal control

III APPROXIMATE COSTS

Computer	\$2-3 K
Wire	\$1./ft
Temp/Analog	\$150./point
Count Rate	
fast	\$450./point
slow	\$ 15./point
On/Off	\$ 15./point
Data Entry	\$200./point

SYSTEM DESCRIPTION

I HARDWARE

The system consists of four basic pieces of hardware. The first is an Apple II computer. The second is our emulator card which connects to the back of the Apple computer. The third is our data card which goes at a monitoring site. The fourth is a control card which goes at a control site.

Attached to the data card by a ribbon cable jumper could be: a standard industrial digital panel meter which can count, read a temperature or read the strip chart output of almost any instrument, or a terminal strip which will read 16 on/off signals (or slow counts) or a thumbwheel set for data entry. The panel meters operate independently from the Apple for simple installation and check out.

The control card would connect to a relay rack and could open or close individual relays on command. The control card could also be used to enter a binary number into a digital to analog converter for proportional control.

The data and control cards plug into a card cage which connects to the emulator card via a 20 conductor cable according to a simple pin assignment.

The system provides a diagnostic program meant to allow the system to be diagnosed and maintained by the user. It freezes the 20 conductor cable and displays the status of each line. A simple volt meter is used to determine if the status is correct and repair is by the replacement of a plug in component.

II - SOFTWARE

The system allows two ways to operate the system.

A. Direct call up of data by P0KING the address of the point to be read (stamped on the data card), the number of digits to be read (1-4), and a 1 if it is a multichannel panel meter into 3 memory locations. Then simply CALL the system driver, and PEEK the data directly from memory.

To control a relay the control card address, the relay number on that card and a 1 for on or 0 for off are POKED into memory and the driver is called to execute the command.

B. The alternative is to use the system control and operating program. It executes all program lines begining at lines 6000 (ending by 6999), 8000 (ending by 8999), 10000, etc. through 34000 every 30 seconds. These locations are used for applictation portions of the program. A user simply begins his program lines at one of these unused line numbers and ends with: GOTO 950.

The system also executes the program lines begining at lines 7000, 9000, 11000 etc. through 35000 in sequence, one every 2 minutes. These lines are used to display information related to the "control" program lines at 6000 (whose data is displayed by lines begining at 7000), 8000 (whose lines are displayed by lines begining at 9000), etc. This allows each application sub-program to have 2 minutes of uninterupted screen time for display of information. This "display" sub-program must be ended with: RETURN.

Finally, the system provides four subroutine which the application portions can call to retrieve data from the instruments, control points on the control cards, store data in Visicalc format on diskette and decode the number from the data card into 16 on/off signals. These subroutines are called by a simple GOSUB XXXX where XXXX is the line number which begins the desired subroutine (except the storage routine which is called with a GOTO XXXX).

SYSTEM OPERATING PROGRAM TECHNICAL SUMMARY

Get data subroutine:

Accessed by: GOSUB 1500
Set up:Load array AD(i,j) where i=1 to 10 and j= 0 to 2
AD(i,0)=Address of data card (stamped on card) to be read.
AD(i,1)=Number of digits to be read (1-4)
AD(i,2)=1 if the card is connected to a multi-channel panel meter, 0 if not.
Result-The AD array will return with the AD(i,0) member equal to the reading on the data card whose address was contained in AD(i,0) when the subroutine was called.

Store data on diskette subroutine

Accessed by: GOTO 1200
Set Up: Load array ST(i), where i=1 to 15
F$="FILENAME" i.e. F$ is a string varialble you set equal to the name of the file you wish the data to be stored under.

Get status bits

Accessed by:GOSUB 1700
Set up:Set the variable SB equal to the reading of the data card with the on/off adapter card attached.(SB=READING:GOSUB 1700)
Result-array B(i) will return with the high status bits 1 and low status bits 0. i.e. if status bit 1 (terminal 1 on the on/off adapter) is high (contact closure to DC ground) then B(1)=1.

Control Subroutine

Accessed by:GOSUB 2000
Set up:Load array CC(i,j) where i= 1 to 10 and j=0 to 2

CC(i,0)=Address of target control card
CC(i,1)=Relay attached to control card (1-8)
CC(i,2)=If 1, turn relay ON; if 0, turn relay OFF

EXAMPLE OF A 'WRITE YOUR OWN' APPLICATION SUB-PROGRAM

This program will:

1.Read an instrument or thumbwheel setting from the data card with address number 7.

2.Turn relay #1, on the control card with address number 25, ON if the reading equals 100 and OFF if the reading equals 150.

3.Store data for later use in Visicalc

4.Display the information on the screen.

PROGRAM:

```
6000 AD(1,0)=7:AD(1,1)=4:AD(1,2)=0
6010 GOSUB 1500
6015 RD=AD(1,0)
6020 IF AD(1,0)=100 AND S=0 THEN GOTO 6100
6030 IF AD(1,0)=150 AND S=1 THEN GOTO 6150
6040 GOTO 930
6100 CC(1,0)=25:CC(1,1)=1:CC(1,2)=1
6110 GOSUB 2000
6115 S=1
6120 GOTO 6200
6150 CC(1,0)=25:CC(1,1)=1:CC(1,2)=0
6160 GOSUB 2000
6170 S=0
6200 ST(1)=MT
6210 ST(2)=D
6220 ST(3)=H
6230 ST(4)=M
6240 ST(5)=RD
6250 F$=FILENAME
6260 GOTO 1200
7000 REM***DISPLAY SUBROUTINE FOR FIRST APPLICATION
SUB-PROGRAM
7010 HOME:PRINT"INSTRUMENT READING="RD
7020 RETURN
```

END OF PROGRAM

BACKGROUND

Each data and control card has a unique 'address' which is written on the card. An array is a table of information with x rows and y columns. A piece of information is designated by the array name and the row number and column number where it is located i.e. AD(4,1) is a piece of data in table AD in row 4 and column 1. The operating program uses 3 arrays or tables. Array AD has 10 rows (1 -10) and 3 columns (0-2). Column 0 holds the address of the data card to be read, column 1 holds the number of digits to be read (1-4) and column 2 determines if the data card is attached to a 6 channel temperature or analog meter if it is a 1 and 0 if it is not. The array allows the reading of 10 data cards at a time (each row holds the information for 1 data card). The data is retrieved by calling the appropriate subroutine (GOSUB 1500). The data returns in column 0 and at the row that contained the address of the data card it was retreived from.

The control array is 10 rows and 3 columns. Each row holds the information for one relay. Column 0 holds the address of the control card to be called, column 1 holds the number of the relay to be controled (1-8) and column 2 is 0 if it is to be turned off and 1 if it is to be turned on. Control is executed by calling the appropriate subroutine (GOSUB 2000).

The storage array (ST) is 20 rows and 1 column. Each row contains a number that is stored for entry into Visicalc. The data will come up in Visicalc as a single row 20 columns wide. Each succesive storage will APPEND the new data as the next row in Visicalc. The storage is executed by transfering program control to the appropriate line number (GOTO 1200).

The month, day, hour, and minute are available to the sub-program from variables MT, D, H, M respectively. The application program section uses the variables RD, for the reading from data card 7, and S for the status of the relay (1=on , 0= off). The relay status prevents the computer from continuously reactivating the relay if it is already on and the conditions remain the same. Not using this will make the relay ficker on/off.

THE PROGRAM STEPS

AD(1,0)=7 Load data card address (can be 1 to 255) into data retrieval array in row 1 and column 0.

AD(1,1)=4 Tell the program that there are 4 digits on the panel meter by loading the number of digits to be read into row 1 and column 1 of the AD array.

AD(1,2)=0 Tell the program that the data is not comming from a multichannel meter like the 6 channel thermocouple meter which requires a delay between readings to change channels (a 1 would indicate that it was).

GOSUB 1700 Execute data retrieval subroutine

AD(1,0)=RD Save the reading for display purposes

IF AD(1,0)=100 AND S=1 THEN GOTO 4100 If the reading is 100 then go to portion of program that turns the target relay on.

IF AD(1,0)=150 THEN GOTO 4150 If the reading equals 150 then go to portion of program that turns the target relay off.

GOTO 930 If the reading is not 100 or 150 then return to operating program.

CC(1,0)=25 Load the target control card address (can be 1 to 255) into control array row 1 and column 0.

CC(1,1)=1 Load the target relay (can be 1 to 8) on control card 25 into control array row 1 and column 1.

CC(1,2)=1 Set array to turn the relay on (0= off).

Gosub 2500 Execute control.

Goto 4200 Store data for later use in Visicalc.

CC(1,0)=25:CC(1,1)=1:CC(1,2)=0 Same as above but turn relay off.

ST(1)=M:ST(2)=D etc. Set the month day, hour and minute for storage on diskette as the first 4 columns in visicalc.

ST(5)=RD set the reading from data card 7 for diskette storage as the 5th column in Visiscalc.

GOTO 1200 Execute data storage under the name assigned to the variable F$. If F$ exists on the diskette then the new data will APPEND to the end of the file. The computer will then return to the operating program.

HOME:PRINT... Clear screen and print information

RETURN Return to operating program.

THE ENERGY MANAGEMENT AND CONTROL SYSTEM SELECTION PROCESS: THE CRITICAL COMPONENTS

Wayne E. Clark / William S. Fleming
W.S. Fleming and Associates, Inc.

Energy conservation through energy management has been, and remains, one of the most viable "energy resources" available to all sectors of the energy consuming building community. Energy conservation not only means free participation by the new and retrofit sectors of this community in an effort to save our "natural resources", or better utilize the resources we have, but the high cost of the energy we require to maintain our business activities precipitates energy management to minimize energy consumption. By minimizing the energy consumption and still maintaining the posture required for our business activities, we can save "money" and therefore survive in our respective market areas.

The major question we all ask ourselves now is "what can be done" or "what opportunities are available to me to minimize the energy requirements for our respective business?"

There are energy saving opportunities for every business where energy savings and associated operating cost savings with beneficial financial advantages that can be achieved.

Process to Follow Prior to Consideration of an EMCS System

First, to achieve energy conservation results, a sound energy management plan must be developed and organized. To be effective, the program must have a reasonable target and timetable, adequate technical information and resources for implementation, a firm commitment on the part of management, and a sound consistent "plan of action".

To achieve a "plan of action" that can be implemented, the primary task that must be performed is the identification of energy conserving opportunities specific to your facility and its product, process and/or HVAC systems. I cannot emphasize enough the importance of performing an "energy audit" that will establish the relative energy performance of your respective operations, facilities and systems to identify the sources of excess energy consumption. You cannot "reduce" or "manage" your energy consumption if you do not first know where they are and what alternatives are available to reduce or eliminate them.

The energy audit begins by performing an analysis of your building's energy history and present consumption. The energy use profile derived provides important information that is used in determining the component contributions by individual process, environmental and envelope systems comprising your total facility.

The energy audit then proceeds with a detailed survey of all the HVAC system(s), lighting, envelope, occupancy schedule and facility use patterns. This survey yields detailed technical information identifying all possible energy conserving actions.

The specific energy conserving actions or conservation projects can be divided into three general categories:

1) Operation and maintenance procedures that provide immediate no-cost, low-cost energy saving opportunities;
2) Modification of existing equipment and systems that generally requires additional technical evaluation and preliminary design;
3) Innovation(s) in the design and operation of new equipment and systems that can be interfaced.

Now, you have identified all possible energy conserving actions and projects that can feasibly be implemented.

The technical evaluation and preliminary design requirements for each project, that are not classified as an operation and maintenance procedure (Item 1 above), will identify the specific components and interface requirements that quantify capital requirements necessary to implement the retrofit. The specific design for each retrofit will also provide detailed information required for the development of equipment specifications.

An economic evaluation can now be performed for each energy conservation project. Quantification of the energy reducing potential for each project, relative cost of energy, and total capital requirements to implement each retrofit project will yeild cost-payback results that will prioritize each project in terms of payback year(s).

You have now; 1) identified all energy conserving actions; 2) technically evaluated the retrofit feasibility to include preliminary design and quantified the energy saving potential;

3) identified the budgetary capital costs for implementation and; 4) economically evaluated and prioritized every retrofit option.

The allocation of resources or "capital" for all retrofit options, identified by the energy audit should be strongly considered and/or provided. However, it must be within the economic criteria established and financial capabilities of your company. Management will provide the adequate funding if; 1) they understand that they are investing ey and not spending it; 2) confident that the amount of savings jected is correct and; 3) they realize that energy costs will continue to escalate. An investment in energy conservation now will increase his buildings future value.

Consideration of an EMCS as an Energy Conservation Alternative

An Energy Management and Control System (EMCS) is one energy conservation alternative that can provide a means to control, reduce and perhaps eliminate energy waste within your business activities.

A common mistake that is made however, is the purchase of an EMCS before an energy audit and evaluation is performed. Often simplified forms are provided by the vendors, for you to complete, that quantifies the energy consumption by fuel type. This information is then evaluated using various assumptions.

Some of the general assumptions used by EMCS suppliers that have a major impact on the quantification of energy saved are:

- Scheduling of HVAC equipment
- Duty cycling
- Power demand control
- HVAC control
- Optimization of heating and cooling
- Lighting
- Nighttime temperature reduction
- Daytime temperature reduction

These types of general assumptions, are often used by vendors, to generate an economic rate of return and payback period for the EMCS investment.

Before any consideration to purchase an EMCS is made, the type of control, the controlled equipment, the systems to be controlled, the control interface requirements, the energy reduction techniques and ential quantities of energy must be specifically established. A t-benefit analysis can then be performed and prioritized for other energy conservation retrofits and even EMCS options.

A specific example of the common mistakes that are made without identifying energy conservation alternatives before purchasing an EMCS happened to an upstate New York regional office headquarter's facility. A well established EMCS vendor successfully approached the management of this firm and they elected to install a large EMCS at an initial cost of $125,000. The savings projected by the EMCS vendor, that included all of the previously mentioned general assumptions, was approximately $45,000 annually. Obviously the savings projected an extremely attractive, simple payback period of 2.78 years. The vendor supplied all of the general installation specifications and an outline of the equipment to be supplied. When the contract documents were finalized, the vendor then went to the superintendent of buildings and grounds to specifically obtain necessary installation information required by the vendor. The very first question posed by the EMCS supplier to the superintendent was, "You now have the energy management system, what do you want to control?"

To summarize the results of this action, the vendor did include various control interface equipment required to accomplish; 1) the equipment control necessary to achieve the predicted savings and 2) adequately control the systems required by the superintendent. The final installed cost of the EMCS was $175,000 and the actual first year savings was $28,000. The resultant simple payback period was extended to 6.25 years.

Obviously, had a "plan of action" been pursued, the EMCS would have from the start been fully defined and perhaps may have even been foregone for other energy conservation retrofits.

An energy management and control system can be an effective energy conservation option when all opportunities for control equipment and systems have been carefully analyzed. The specific EMCS functions and capabilities can be specified to meet the needs of a building owner, and correspondingly the EMCS available on the market today can be evaluated to assure that current and future needs of the building and its operations have been provided.

Cost Effective Design

The same procedure in developing a cost-effective design for other energy conservation retrofits should be followed when the decision to implement an EMCS is made. The existing equipment control system should remain in control. The energy management and control system should only interface with the existing control network and provide the capability to maximize the control sequence, as a result of predetermined parameters and resultant software programs.

Professional help, such as the consulting engineer, can offer unbiased technical expertise as well as experience to the owner during the design and specification phase. Consistent with the results of the energy audit together with the decision to install an EMCS as an energy conservation alternative, a cost-effective design should be developed prior to requesting proposals from EMCS suppliers.

The design should be specific and define the hardware required for the local control loop interface. The local control loops operating in present facilities have been employed very successfully for years. The hardware specified to fit each application should utilize a standard line of energy controls and optimize existing control hardware in other control loop applications if replacement or upgrading of existing controls is required to accommodate the EMCS interface.

W.S. Fleming and Associates, Inc. (WSFA) was employed by an upstate New York hospital to develop a cost-effective control interface design and specifications to implement selected energy retrofits (recommended as a result of an energy audit performed by WSFA).

The selected retrofits included hot deck reset, enthalpy controlled economizers, cold deck reset, and chilled water reset. A thorough review and analysis was performed of the existing control network and components. The anlaysis revealed that the majority of pneumatic controls could be incorporated in lieu of the retrofit requirements. New receiver-controllers were required to perform the control sequence, however future consideration (as revealed by the energy audit) for an EMCS was indicated by the client which permitted not only a cost effective design of the existing control network but optimized the control functions for future EMCS interface. A total of six HVAC systems were selected to receive the aforementioned retrofits. All six HVAC systems required new receiver-controllers, however for an additional $35 per controller, the capability to be remotely reset by an EMCS was provided. The savings generated during the design phase saved the client $1,890 in controller costs. By utilizing the existing control components, in other control loop applications, an additional $3,500 was saved.

The control companies did not like this approach because they claimed they were responsible for control system engineering. In fact, when the specifications were disseminated for control equipment and related hardware, two control companies declined to provide bids.

Cost effective designs can be achieved and resultant savings accomplished when an effort is pursued to apply identified control techniques to HVAC system operation consistent with the control desired.

The cost effective design is not only limited to hardware and control components. The EMCS optimization functions that are required to accomplish the specific control of equipment and systems should be identified in the energy audit. The specifications developed for the control components and hardware should include the software specifications required. The EMCS should have the capability of providing for all control required, but must also have provisions that allow parameters to be changed when necessary. This will allow the operator to "fine tune" his operation, optimize the control potential and control his facility and operation to maximize the savings potential; while meeting his own particular control needs.

Means of Evaluating Proposals by EMCS Suppliers

There are a multitude of EMCS suppliers in the market today that range from; residential EMCS to Facilities Management Systems which include energy management and control system capabilities with the ability to handle control of the environment, protection of assets and properties, access control and personnel management.

If a person follows what we believe is the correct procedure, and identifies the energy conservation alternatives, evaluates the economic advantages, developes a preliminary design and identifies the optimization functions and hardware components required, that person is ready to request and evaluate proposals. The best means to evaluate proposals submitted by EMCS suppliers is through the development of specifications from which the proposals have to comply. All of the information required to develop specifications will be assembled. The specifications should be disseminated to various EMCS suppliers and when the proposals are submitted a technical evaluation;

1) can be performed to assure compliance with the specifications;
2) assure adequate capabilities meet the buildings future needs and;
3) analyze competitive cost comparisons.

If this procedure is followed, building management and/or professional operating engineers can eliminate a vast majority of EMCS suppliers who; cannot meet the requirements you have specified, cannot compete due to the complexity of their system, or provide excess "fringe" equipment that does not effect the optimization functions you require.

When the evaluation of all proposals have been completed, the EMCS purchaser, staff and/or engineering firm should request a list of clients from the EMCS suppliers that currently have an EMCS operating. You should not select an EMCS on first cost alone. Individual information can be obtained from building owners who have had experience operating various EMCS's.

A final decision to purchase a specific EMCS can now be made. All proposals have been evaluated, compliance assured relative to the specification requirements, and the success of the EMCS by actual users, has been determined.

Implementation

The implementation or installation phase is critical to the successful operation and ultimate control of your EMCS. Knowledgeable and competent personnel should be assigned to "monitor" the installation activities of the contractor(s). The personnel selected should be; 1) familiar with the facility and system; 2) experienced in the present control network and; 3) have full understanding of the overall project scope that will provide assurance that all interfacing components and techniques are incorporated during the installation.

Documentation for the "as built" EMCS including interface components provided by the EMCS suppliers should be validated. Init start-up and future problems will require specific reference to the "as built" documentation.

An extremely critical task that must be performed during the EMCS installation phase is control calibration. The new control components which are installed have to be calibrated to assure proper operation. The existing components are often overlooked, however, they too must be calibrated and/or checked. To make the best use of computerized energy management, you must start with efficient, well maintained, operating controls.

Judgements Made and Decision Results

As previously discussed, WSFA has been involved in numerous projects involving EMCS projects. Involvement has varied from energy audits, design and specification development, construction management, system programming to providing professional services to clients who are experiencing dissatisfaction with their EMCS.

The overall judgements made and the decision results are briefly described in the following examples:

Example 1
An upstate New York hospital contracted WSFA to perform energy audit services of their HVAC systems, which resulted in the implementation of retrofit options with a payback of 1.5 years or less. WSFA provided design and implementation coordination services, and analyzed the resultant energy reductions achieved.

The installed cost of all retrofits (including professional consulting fees) was $35,000. The actual total savings achieved for the first seven months (based on specifically measured data) was $60,000. The HVAC system retrofits did not include an EMCS. However, the design for the retrofit options included future interfacing control capability for an EMCS. In the energy audit, an EMCS was identified as an energy conservation alternative with the potential of generating $44,000 in savings annually. The resultant payback for an EMCS was projected at 5.3 years at a projected installation cost of $236,000.

The energy audit of the hospital identified numerous opportunities for energy conservation. As a result, the hospital implemented options and generated immediate savings for retrofits other than an EMCS. However, an EMCS is a viable energy conservation alternative and if the decision to implement an EMCS is made in the future, all the "critical components" have been identified that will insure a compatible system installation and operation.

Example 2
An upstate New York office complex purchased an EMCS to reduce their energy consumption and control their HVAC operation. An energy audit was performed by WSFA. However, the client declined to have developed a cost effective design and specifications for the HVAC control and interface requirements. The decision to overlook this "critical component" resulted in installation delays, misunderstanding of the total control capability and increased installation costs. Financial accountability resulting from actual energy reduction through the use of the EMCS projected an increase in payback years shedding a "dim" view from management for future energy conservation investments.

Example 3
Another upstate New York based medical hospital and college facility contracted WSFA to perform an energy audit of the facilities and HVAC systems. The results of the energy audit identified a multitude of energy conservation projects including specific HVAC and lighting control opportunities that warranted the investigation of an

EMCS. WSFA developed preliminary design and specifications for an EMCS consistent with the specific operational control required.

The requests for proposal and specifications were disseminated for responsive bids to be submitted by the EMCS suppliers. The proposals were reviewed and the EMCS was purchased. WSFA provided implementation coordination services during installation and the EMCS installation was completed and operational, on time.

The EMCS is fully operational and meeting the control requirements necessary to control the facility environment and maximize the energy savings potential. The installed cost was $200,000 and the EMCS is fast generating savings at approximately $80,000 per year and is expected to meet or exceed the projected 2.5 year payback.

Conclusions

Again, the critical components vital to an Energy Management and Control System selection process are:

1) Development of an energy management plan
2) Identify energy saving opportunities by performing an energy audit
3) Provide technical evaluation and preliminary design requirements
4) Perform an economic evaluation for each energy conservation project.

If an EMCS is considered as a viable energy conservation alternative, before purchasing:

1) Develop a cost effective design
2) Produce EMCS specifications
3) Evaluate proposals
4) Select the most effective EMCS
5) Install and operate EMCS according to design specifications and energy management procedures.

A UNIQUE ELECTRIC POWER MANAGEMENT SYSTEM
OF
YOU CAN'T MANAGE WHAT YOU CAN'T MEASURE

E. Eugene Mason
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Hampton, Virginia

INTRODUCTION

The National Aeronautics and Space Administration in 1976 established a goal of reducing its Centers' energy consumption 50% by 1985, using 1973 as a base year. The Langley Research Center, located in Hampton, Virginia, is the oldest of the NASA centers and found in 1973 that 80% of its energy usage was in electric power (196 million kilowatt hours). It was readily apparent that, in order to meet the 50% challenge, drastic reductions in electric power would have to be realized. Firmly convinced that "you can't manage what you can't measure", the Center embarked on a reduction program that featured metering as its principal management tool.

BACKGROUND

The Langley Research Center was formed in 1917 as the Langley Memorial Aeronautical Laboratory. It was at Langley that the nation's manned spaceflight program originated and, even though it still maintains an active space research program, its main research is in the field of aeronautics.

The Center consists of over 150 facilities, including laboratories, administration buildings, support facilities, and 10 major wind tunnels. It is divided, operationally, into seven directorates (Administration, Electronics, Engineering, Projects, Space, Structures and Aeronautics) and has approximately 3000 employees and 1500 support contractor personnel. Most of the facilities are relatively modern but some are over 50 years old.

At the start of the program, the only meters installed were those that monitored the power to drive the major wind tunnels. In 1973 the tunnels used 70 million KWH of the Center's total of 196 million KWH. As emphasis was plac on finding ways of reducing consumption with little or no impact on Langley's research mission, it followed that conservation measures should concentrate on areas not directly affecting research. As a result, a decision was made to include all of the Center's facilities in the metering system.

THE SYSTEM

The metering plan called for the installation of an additional 235 meters for a total of 250. As it would be very time-consuming to read that many meters on a frequent basis, a watt transducer was installed with each meter (Figures 1 and 2). The transducer transmits a 0 to 1 milliamp signal, via dedicated telephone lines, to a centrally located Base Station. There the signal passes through a

Figure 1. Watt Transducer

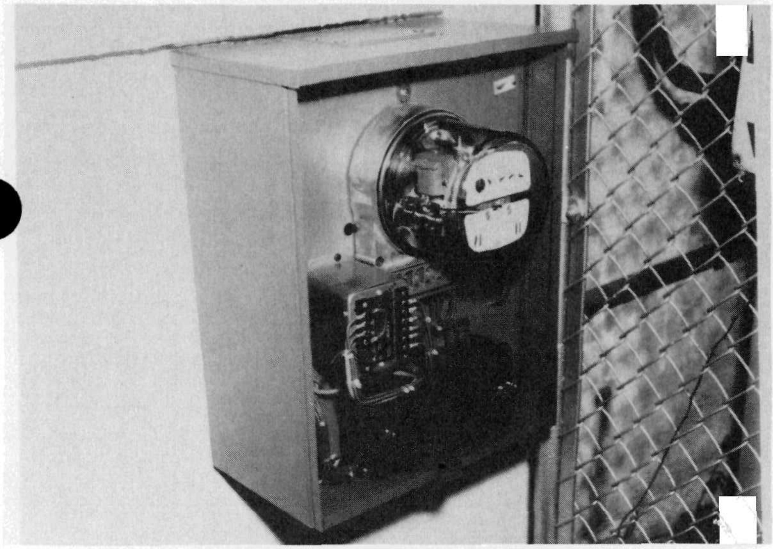

Figure 2. Transducer Installed in Meter Cabinet

signal conditioning card containing a precision resistor. Each meter is scanned every 5 minutes and the voltage drop across the resistor, which is proportional to the wattage at that time, is read by a digital volt meter. The voltage data is converted into engineering units and stored on a computer hard disk. Two computers are used in the system; one is dedicated solely for acquisition of the signals, the second, which may also access the hard disk, is used for the retrieval of the data. The hard disk can store 8 days of 5 minute data before it begins to write over itself. An averaging program converts the 5 minute data into hourly and daily averages and stores these data on another removable disk. Each removable disk can hold 60 days of averaged data.

Each of the facilities at Langley is assigned to one of the seven directorates. Using the power data, annual electric power budgets are prepared for each facility and allocations are made on a monthly basis. A plot of the power consumption of each facility is made each month and forwarded to each of the directorates for review. Summary reports are also prepared and presented to senior management each quarter. As the data are stored on disks, the only printed matter is that which is necessary for reports and then, only on demand. A schematic of the system is given in Figure 3 and the computer equipment located in the Base Station is shown in Figure 4.

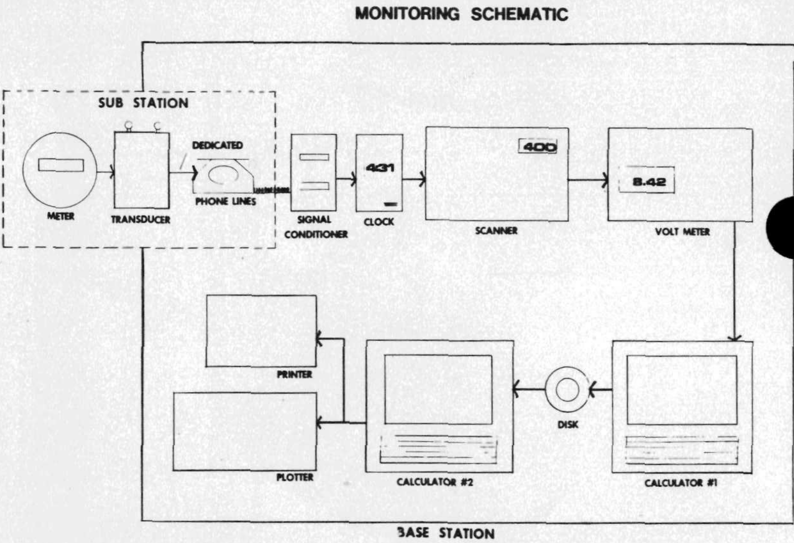

Figure 3. System Schematic

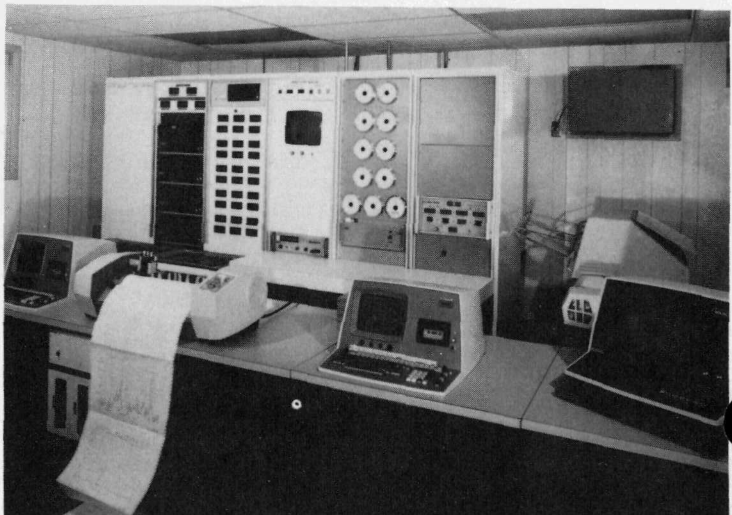

Figure 4. Base Station Computers

DISCUSSION AND EXAMPLES OF RESULTS

Installation of the metering system began in 1976. As building power had to be interrupted during the installation, most of the work was done on weekends and, as a result, the last meters were not installed until mid 1978. There are currently 264 meters in the system with meters being added or removed as operations or new construction require. There are provisions for a growth to a total of [illegible]0 power meters. In addition there are 100 meter channels reserved for steam, environmental and noise monitoring sensors with 35 of those channels now in use.

As the data for each meter are stored separately, it is possible to recall the data in a number of different forms. For example, in the large wind tunnels, power usage can be categorized as to that required for lights, air conditioning, main tunnel drives and tunnel ancillary equipment. These may be plotted separately or as a sum. The power used by a given division or even a directorate can be determined by adding up all of the meters associated with each facility. The data may be presented in any of ten different plot forms or in a number of printed formats. The plots most used are 24 hour plots of 5 minute data, weekend plots of 5 minute data, weekly plots of hourly averages and cumulative plots of monthly actuals. For historical purposes 15 plots of selected power and environmental parameters are plotted daily. Each month a plot for each facility is prepared and forwarded to the responsible directorate manager. Additionally, in a typical year more than 2000 requests for data may be received from facility coordinators as they strive to operate their building in the most efficient manner.

Electric power budgets based on the metering system have been in effect for 5 years. While most of the monitoring effort now is concerned with keeping facility managers informed on continuing conformance with their power allocations, the system is still used to identify and isolate problem areas. As a case in point, the heating plant in 1980 replaced an existing compressor with a new Ingersoll Rand to provide 350 psi air for research purposes. A meter was installed with the new compressor and a plot (Figure 5) of the heating plant meters revealed that the compressor was running almost continuously at 140 KW. As there was very little requirement for air on weekends, a comprehensive search found a large leak in a broken pipe in an underground tunnel. After the leak was repaired, the compressor ran not at 140 KW but at 40-50 KW (Figure 6). The net result was a reduction of approximately 1 million kilowatts in the heating plant power consumption with savings estimated at $45,000. Recently it was determined that it was more economical to shut the compressor down and draw the air from the Center's 5000 pound bottle field.

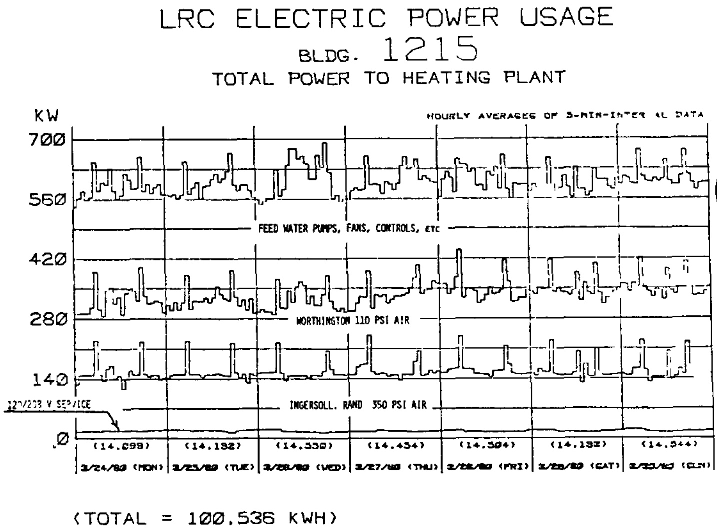

Figure 5. Total Power to Heating Plant

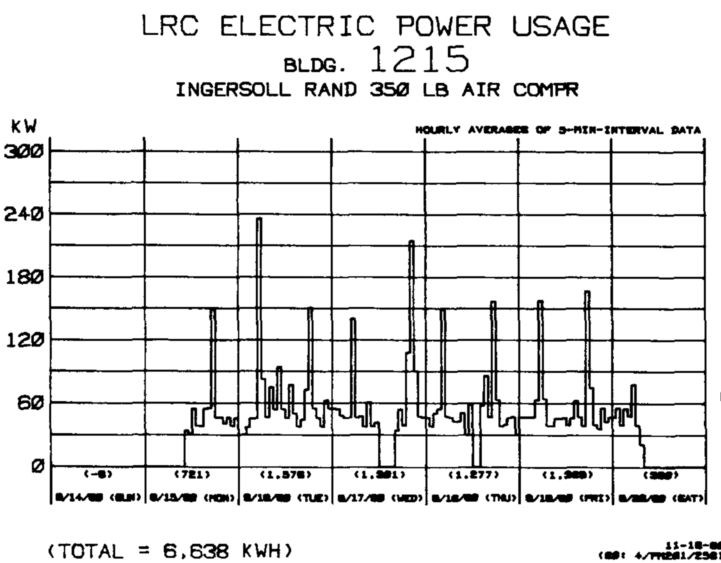

Figure 6. Compressor Power After Leak Was Repaired

Plots which are run periodically as a check on each facility have revealed significant changes in power profiles because of inoperative air conditioning timers, equipment left running continuously, lights left on and problems with air conditioning equipment. As an example, a routine plot of the library showed an unusual cycling pattern (Figure 7). The cycling, caused by two malfunctioning sensors could have lead to compressor burnout. When replaced the compressor returned to normal operations as shown in Figure 8.

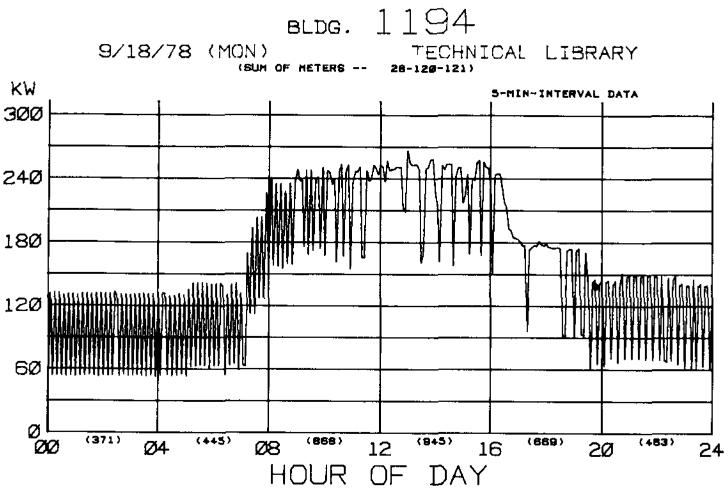

Figure 7. Short Cycling of Air Conditioning Compressor

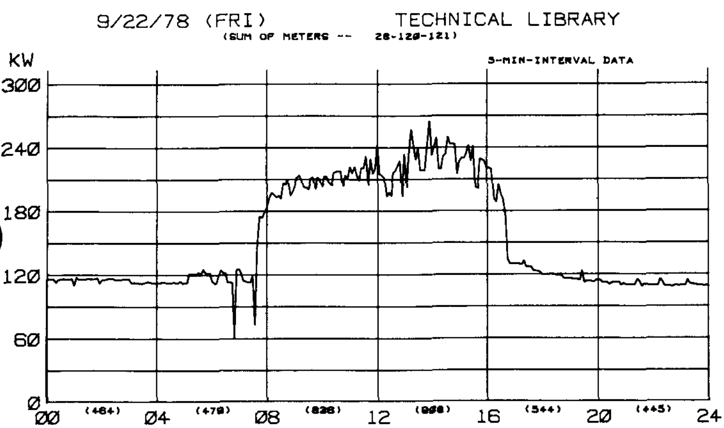

Figure 8. Return to Normal Compressor Operation

Energy conservation at Langley is a continuing program. Since 1973 energy usage has been reduced by 42%. Electric power usage, in spite of new facilities that require 10 million KWH annually, has dropped from 196 million KWH to 137 million KWH. Further reductions in electric power will focus on power used at night and on weekends, for any reductions there should have a minimum impact on research. Previous efforts to reduce weekend power resulted in significant savings. For example, in 1979, in response to a mandate to cut energy by 5% for the year, Langley concentrated on cutting weekend power in selected facilities. The metering system was used to do building electric power audits whereby all power would be shut off to a building and then equipment normally left on was brought back on line one piece at a time. This allowed the facility manager to review the power required for a given function and determine whether there was a less power consuming alternative. In 1978 the Center used a total of 20.5 million KWH over 52 weekends. As graphically depicted in Figure 9, weekend power dropped 3.5 million KWH with a corresponding savings of $150,000.

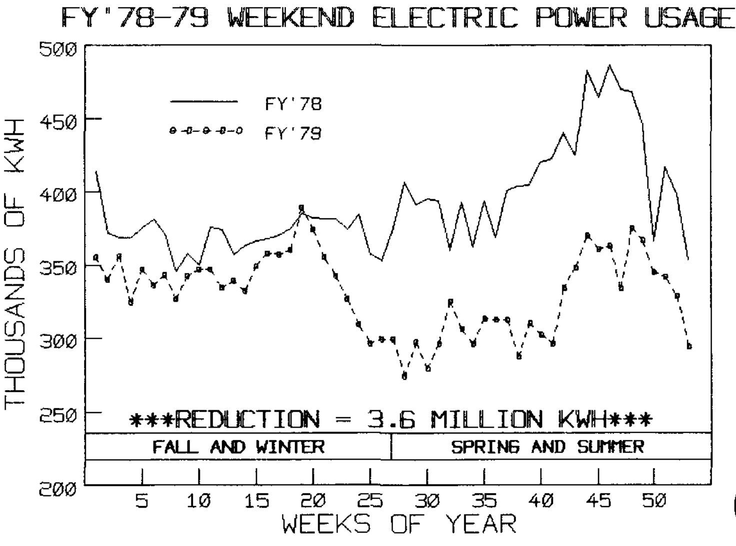

Figure 9. Weekend Electric Power Usage

The question is often raised, "what's the payback time on a meter?" This should not be a factor in deciding on a metering system, for meters are management tools that enable intelligent decisions to be made. If one, however, wished to apply that question to two of Langley's meters the answer would be "less than one day." In August of 1978 a weekend plot revealed that the Center's total power

(Meter #1) increased dramatically between 8 a.m. Saturday morning and 6 p.m. Sunday afternoon (Figure 10). A plot of Langley Air Force Base (Meter #76) also supplied through NASA, showed a drop to zero for the corresponding time period (Figure 11). Investigations revealed that the meter had been inadvertently disconnected during repairs. As the amount of power involved was over 400,000 KWH, a cost of $18,000 was avoided by the Center.

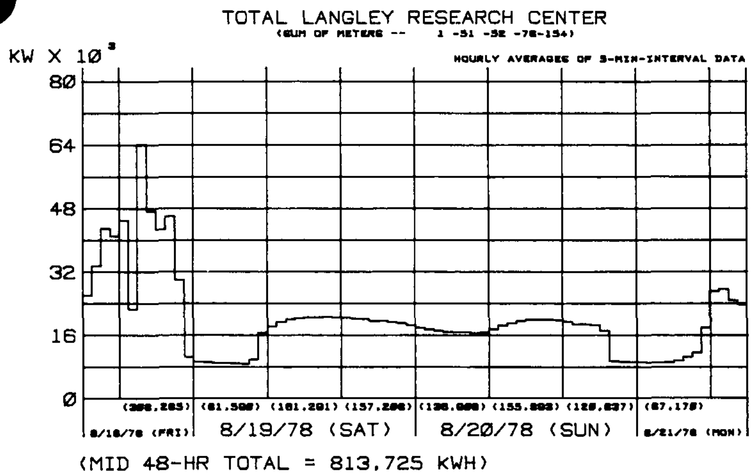

Figure 10. NASA Langley Weekend Plot

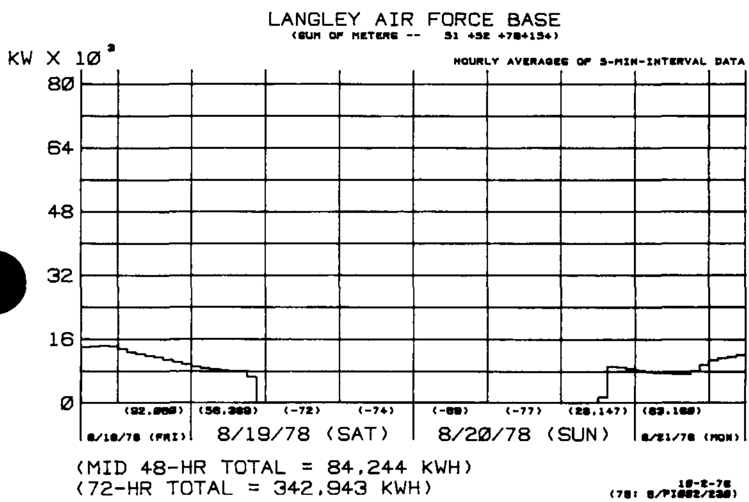

Figure 11. Langley Air Force Base Weekend Plot

CONCLUSIONS

Since its inception in 1977, the Base Station Metering System has proven to be an invaluable tool in the management of the Center's energy conservation program. In addition to the obvious dollar savings the system has brought, it provides numerous other benefits. Its versatility allows the base station to track the data in various ways by directorate, division, individual facility or by meter. It allows the development of energy profiles and serves as a means of identifying energy conservation initiatives and evaluating any reduction methods initiated. Finally, it enables concentration of energy management efforts with a minimum effect on Langley's research mission.

With the continuing rise in energy costs, the Base Station's role in curtailing energy usage remains a vital function in Langley's operational planning. In addition to those savings noted in the report, the cumulative cost avoidance for electric power since 1973 exceeds 15 million dollars as shown in Figure 12.

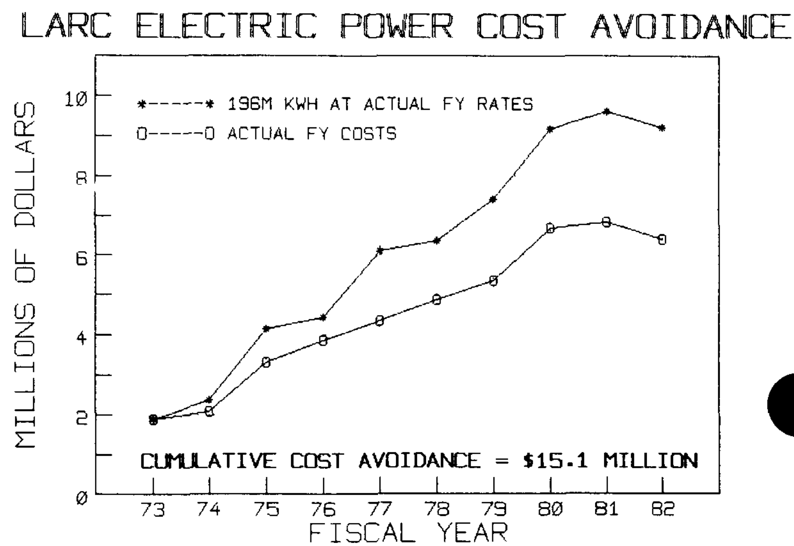

Figure 12. Cumulative Cost Savings

ENERGY CONTROL SYSTEMS SPECIFICATION

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1.0 °INTRODUCTION

The objective of an energy control system, and/or equipment is to cost effecitvely reduce energy consumption.

Defining those energy control strategies which are cost effective requires an in-depth energy savings analysis, and that analysis is the first and necessary step in an energy conservation program.

1.1 °Energy Savings Analysis

For fairly small facilities, and simple operations, a desk-top analysis is usually sufficient to define energy saving projects. In general, a computer simulation is necessary to define the energy waste and, therefore, the energy saving projects of more complex facilities. The approach to energy analysis is first to simulate the actual energy consumption of the facility. The simulated consumption should equal the actual utility bills within ± 10%. The next step is to try energy saving projects or strategies within the computer simulation and arrive at a plan for reducing energy consumption and demand. The following figure illustrates this simple concept.

Computer Simulated Energy Consumption	=	Actual Utility Bills within ± 10%

°Then develop energy savings projects by computer simulation.

An example of an energy analysis effort is summarized by the next figure.

Location: Massachusetts
Building Size: 200,000 FT^2

		ANNUAL CONSUMPTION		
	SYSTEM	ELECTRIC KWH x 10^3	GAS MCF	TOTAL BTU x 10^9
Existing Facility		17,226	35,559	94.35
On/Off Control	1	14,889	35,571	86.39
HVAC Control	2	13,826	13,280	60.47
Mech. Room Control	3	11,977	13,280	54.16
Production Control	4	11,502	9,835	49.09

This building's HVAC control system had a considerable amount of reheat and also did not take advantage of fresh air cooling; therefore the savings for HVAC control were considerable. Mechanical room control included the use of a cooling tower to cool the buildings during the fall and spring months. Production control was basically turning equipment off more effectively, as was System 1, on/off control of lights and motors.

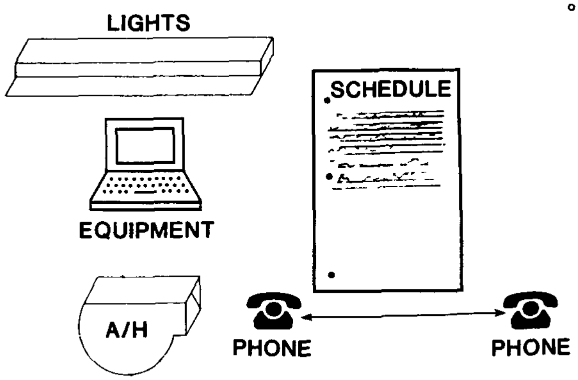
2.0 °BUILDING WITH PACKAGED AIR CONDITIONING UNITS

An energy control system for buildings utilizing roof top or split air conditioning systems is considerably different than that required for a central HVAC system. The following will define energy control system options, starting with very simple systems and increasing in performance with each step.

2.1 °Manual Control

The most obvious system for energy control is to turn equipment off manually when not needed. For large facilities this usually means that a schedule is developed and kept up-to-date so that the person responsible for the task can perform efficiently. A memo or phone call usually defines the schedule or procedures for the person responsible for the turn-off schedule.

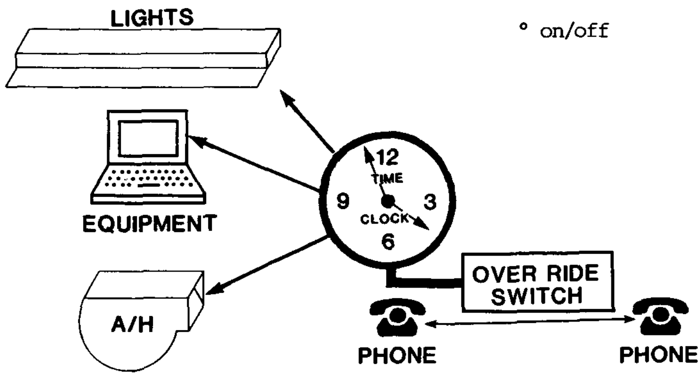
° on/off



The advantage of this approach is that it is inexpensive to install; however, it does not perform many control strategies. Typically, the procedure gradually degenerates to the point that many hours of potential off-time are lost.

2.2 °Time Clock

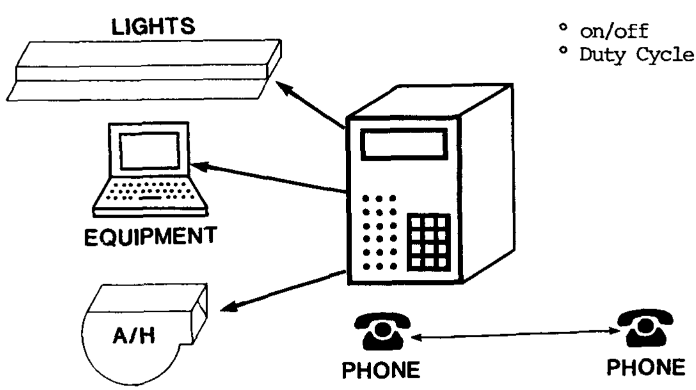
A time clock is the next most obvious method of energy control.



The approach can be effective in some applications, but note that it is essentially the same as manual control. For operations not having a repeatable work schedule, the system can be very troublesome, requiring the need for override. The time clock is usually set for on times which potentially do not conflict with anyone, therefore, the system can be very inefficient. Another major disadvantage is the lack of demand control.

2.3 °"Simple" Energy Control Box

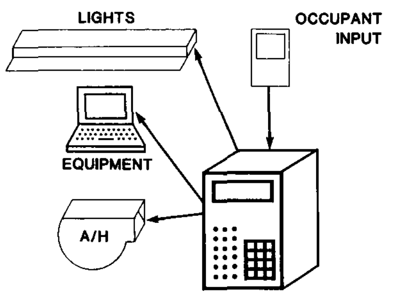
The simplist energy control box performs the same function as a time clock plus duty cycling of equipment based on time.



Duty cycling of air conditioning equipment based on time is a method of demand control; however, control of space temperature can be lost in some applications. Note once again that the scheduling of on/off time is essentially the same as manual control or time clock control.

2.4 °"Digital Input" Controller

The addition of digital input logic allows for the possibility occupants input of on/off schedules. For example, when the occupant turns on the lights, the lights will automatically turn off some time later and also turn off air conditioning and equipment in the space. A blinking of the lights can warn the occupant of impending turn-off, allowing additional input of time by the occupant.

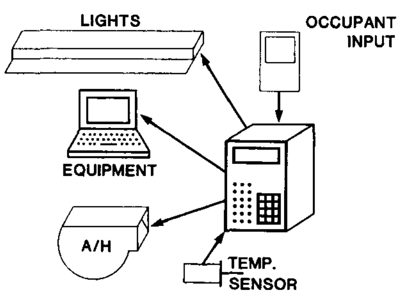


- ° on/off
- °Duty Cycle

This type system is particularly advantageous in office buildings, schools, manufacturing and other operations where strict time-of-day control is troublesome and potentially inefficient.

2.5 °"Analog Input" Control

The addition of analog input to the controller provides significant performance improvements.

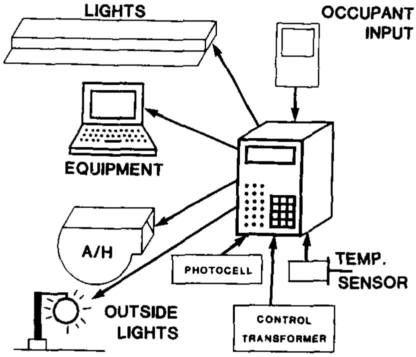


- ° on/off
- ° temperature compensated duty cycle
- ° temperature set-back, set-up
- ° optimum morning start

The purpose of duty cycling is to assure that all air handlers are not on when less can meet the space loads. Temperature compensations assure that the space does not become uncomfortable. Analog also provides after hours temperature control and optimum morning start-up to minimize demand kilowatts (KW).

2.6 °"Sensor Input" Control

The next step in control sophistication is demand control based on a set KW limit and also the incorporation of sensor inputs to control loads, for example, outside lights.

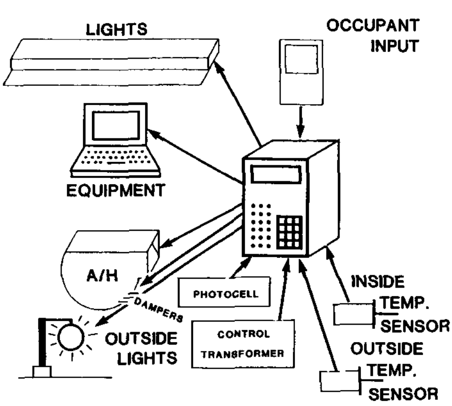


- ° on/off
- ° temperature compensated duty cycle
- °temperature set-back, set-up
- ° optimum morning start
- ° demand control
- ° outside lights

Demand control requires that something must be turned off when KW reaches a certain upper limit. Defining what to turn off is typically very difficult, and in many cases, has been abandoned after a test period. Nevertheless, it can be an effective control feature in some applications.

2.7 °"HVAC Optimization"

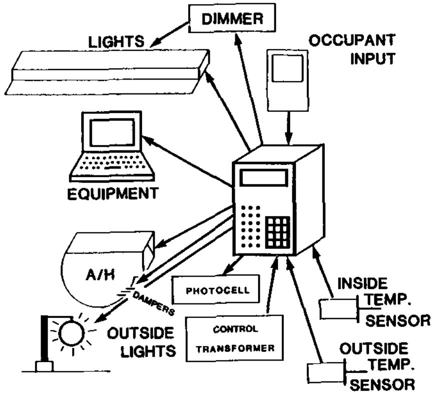
A controller capable of optimizing HVAC control can provide very large energy savings and, in most cases, cost effective energy savings. Features of control include temperature dead band, use of outside air cooling, eliminating the possibility of heating and cooling occurring at the same time, using lights for heating when appropriate, sensing outside doors open, and other features for specific applications. The following figure illustrates the system.



- on/off
- temperature compensated duty cycle
- temperature set-back, set-up
- optimum morning start
- demand control
- outside air cooling
- eliminate reheat
- sensor inputs

2.8 °<u>"Demand Optimization"</u>

Demand optimization is defined as proportional control of demand. For example, the lights can be dimmed and/or the space temperature can slightly go out of set point. Equipment control is also a possibility. The following figure illustrates the concept.



- on/off
- temperature compensated duty cycle
- temperature set-back, set-up
- optimum morning start
- demand control
- outside air cooling
- eliminate reheat
- sensor inputs
- demand optimization

This level of control requires a fairly sophisticated controll[er] with ease of programming as is necessary to facilitate many control strategies.

2.9 °<u>"System Expandability"</u>

Installing a controller which is upwardly expandable is very important to the long-term cost effectiveness of an energy conservation program. Many energy conservation products on the market are not presently cost effective, but very likely will be in the near future. Products and ideas to consider in the selection of an energy controller include the following:

°Variable spped control of motors
°Roof spray
°Evaporative cooling of the facility
°AC coil evaporative cooling
°Signals from local utility company
°Ceiling fan control

The author recommends that a controller be selected which is presently capable of controlling these types of products and ideas.

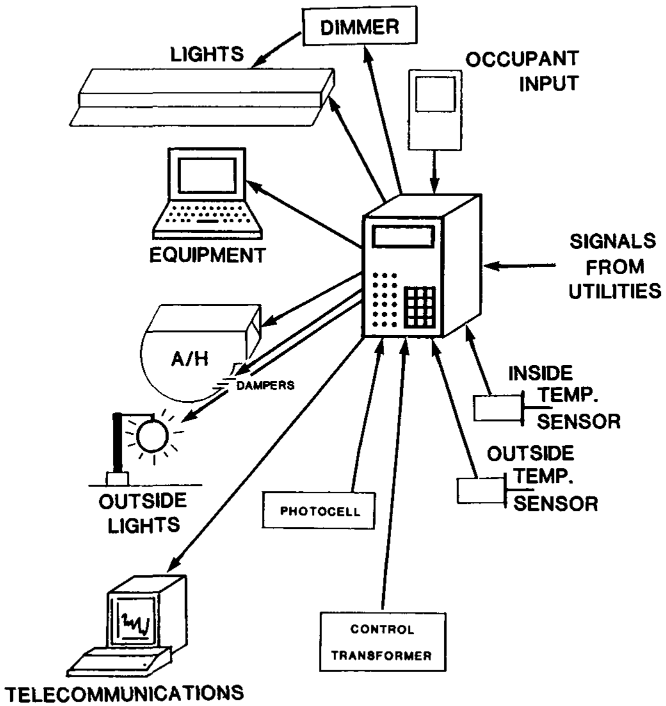
2.10 °Telecommunications

In many applications telecommunications can be a necessary feature of a successful energy conservation program. Knowing when a system is not performing properly is the most important reason for telecommunications. The abilities to reprogram the system and analyze its performance are also key features.

Selecting a controller which is capable of telecommunications is very important to the long term success of an energy conservation program.

2.11 °Conclusion

The following figure illustrates the potential scope of a total energy management system. The opportunities for energy savings are apparent when compared to a time clock or "simple" energy control box. Understanding these potentials for saving energy costs and the evaluation of their cost effectiveness is a technical problem which can only be effectively addressed by those with considerable experience in the field.



- on/off
- temperature compensated duty cycle
- temperature set-back, set-up
- optimum morning start
- demand control
- outside air cooling
- eliminate reheat
- sensor inputs
- demand optimization
- telecommunications
- expandable controller
- speed control
- roof spray
- evaporative cooling
- utility control
- etc.

3.0 CENTRAL HEATING/COOLING SYSTEMS

Central heating/cooling systems are defined as system which centrally produce and pump hot or cold fluids to the point of use for space conditioning. For example, a large DX system may pump conditioned air around the facility via large fans. A more common example is a system which pumps chill water, hot water or steam to points of use through the facility.

3.1 °Levels of Control

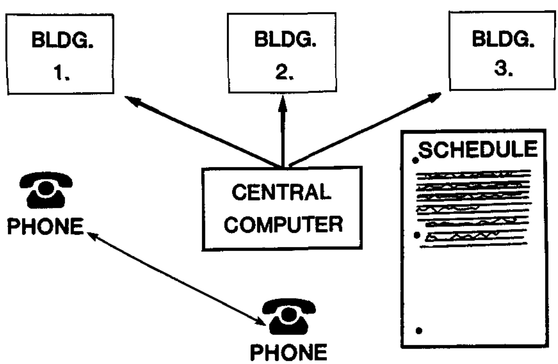
An energy control system for centrally cooled/heated facilities can be defined by seven (7) levels of control:

Level (1) On/off Control
Level (2) Demand Control
Level (3) HVAC Control
Level (4) Production Control
Level (5) Mechanical Room Control
Level (6) Site, monitor and control station
Level (7) Telecommunications

Each of these levels of control can usually stand alone or in any combination with the exception of Levels 6 and 7.

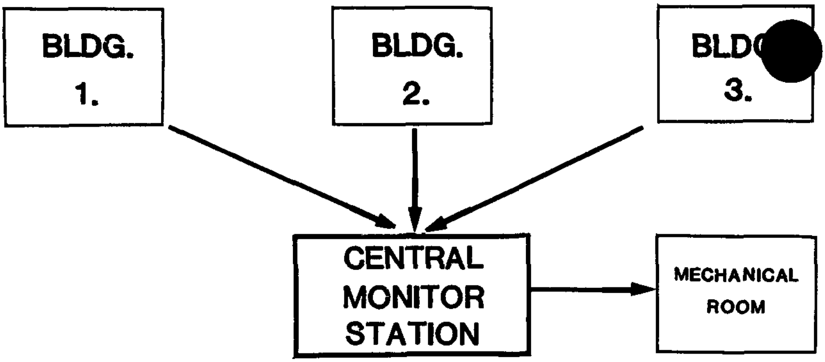
3.2 °Central Computer

As with packaged HVAC systems, as defined above, manual control and time clock control are the most obvious methods of on/off control, and the discussion above generally applies here. The figure below illustrates an approach to on/off control which has been installed in many facilities. The control concept is really not much more than a time clock with Level (6) monitoring. The problems of scheduling on/off times are essentially the same as a manual system in that a computer operator inputs the on/off schedule based on input from the occupants. The occupant providing those inputs either by phone or memo.



3.3 °Decentralized Control

Decentralized control is based on the concept of small stand alone controllers operating totally independent of a central computer. If a central computer is incorporated (Level 6), it is only for purposes of monitoring.

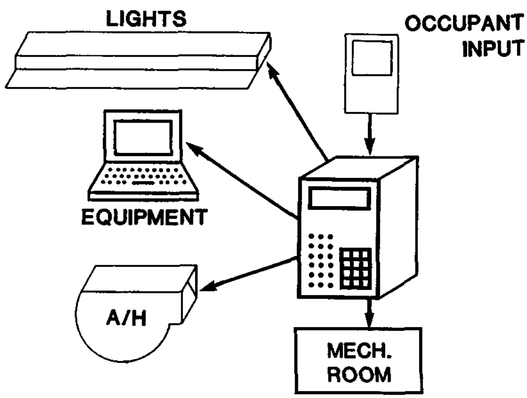


The stand alone controller can be a rather simple device for on/off control or a controller capable of HVAC control, mechanical room equipment control and even process control. The control power and flexability offered by this approach is considered by some to be a major advantage for decentralized control.

3.4 °Level 1 and 2 - On/off and Demand Control

The figure below illustrates total site on/off and demand control. The ability to control the mechanical room based on requirements across the site is a major feature of this approach.

° on/off control
° demand control



Each building controller is a stand-alone on/off controller acting independently from all other building controllers. If further we assume the building occupants' input to the building controller, the number of hours of service desired, then we have a more efficient system for on/off and demand control.

3.5 °Level 3 - HVAC Control

Five choices exist for HVAC controls -

°Pneumatics
°Reset Pneumatics
°Modulated Pneumatics
°Close Loop Control - Pneumatic Actuators
°Close Loop Control - Electric Actuators

The following will briefly discuss each choice in order of control capabilities. The control strategies to be considered are:

°Space temperature deadband control; for example, cool at 76 degrees F, heat at 70 degrees F.
°Use outside air for cooling
°Variable air volume control
°Fan on/off control based on temperature, time or other input
°Eliminate reheat
°Control dehumidification
°Space pressure control
°Provide space requirements to the central utility plant
°Alarm when energy is being wasted

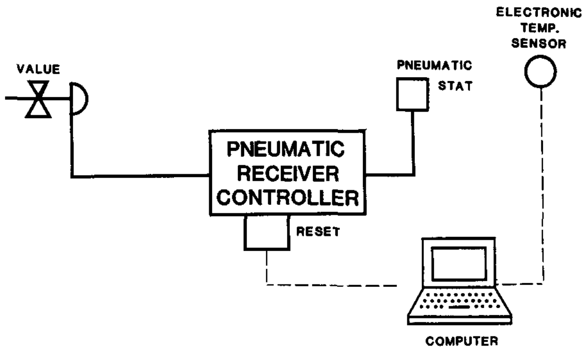
3.51 °Pneumatic Controls

Pneumatic controls offer a wide range of control capabilities, but a recently published study (ASHRAE Journal Nov./1982) has shown pneumatic controls may be very inefficient because of the difficulty of maintaining calibration. The author has personal experience which substantiates the ASHRAE article. Therefore, it is probably true that pneumatic controls cannot be depended on for complex control strategies, as suggested by the list above.

3.52 °Reset Pneumatics

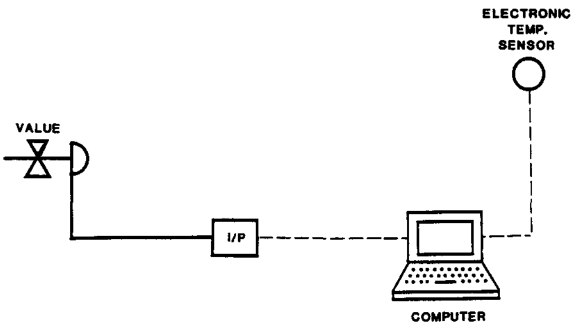
Resetting pneumatic controls by the incorporation of computer [illegible]itoring has been implemented in many facilities. The difficulty with the approach is that it does not do away with the basic calibration problem with pneumatic controls. Therefore, very often the anticipated improvement in energy savings does not occur.

A typical example is illustrated on the following page. Two temperature sensors are in the space, one pneumatic which originally controlled the valve and a second with an electric sensor which resets the pneumatic controller.



3.53 °Modulated Pneumatics

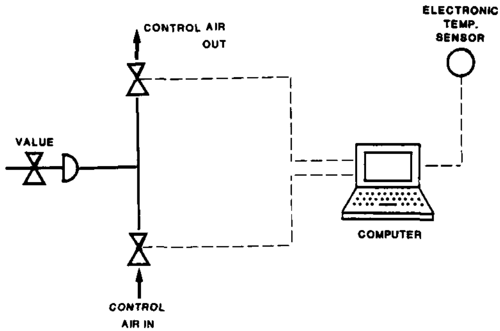
Modulated pneumatics appears to be an improvement in HVAC controls. The concept is based on trapping control air on the valve and allowing a very small amount of control air to exit or enter the valve air chamber. The computer puts out digital signals to the air solinoid valves which control the pressure on the valve and also its' position.



The advantage of this approach is that electronic controls can be "snapped on" the existing pneumatic system.

3.54 °Close Loop Control - Pneumatic Actuators

Cl-se loop control is a move toward process control techniques.



An electronic temperature sensor in the space provides close loop control of the valve.

The I/P transducer changes the electrical control signal from the controller to a pnuematic signal to the valve. Controllers are available which provide (PID) proportional, integral and derivative control. The following "figure 1" illustrates an airhandler control which provides the feature of minimizing energy consumption consistent with meeting the space requirements.

3.55 °Close Loop Control - Electric Actuation

The next step is to eliminate the pneumatics and use electric actuators. Recent developments and improvements in electric actuators is the inevitable system for efficient energy control in new buildings.

3.6 °Level 4 - Production Control

Control of production processes cannot be excluded from an energy control system. First of all, the process should be efficiently controlled. Second, if the process requires energy from the mechanical room, then the efficient operation of the mechanical room is dependent on controlling the process. The selection of an energy control system is very often driven by the production control considerations.

3.7 °Level 5 - Mechanical Room Control

The efficient control of the mechanical room is a key element of the Energy Control System. Many options exist depending on the particular system; however, in general, the control of a mechanical room is based on two principles:

HVAC CONTROL

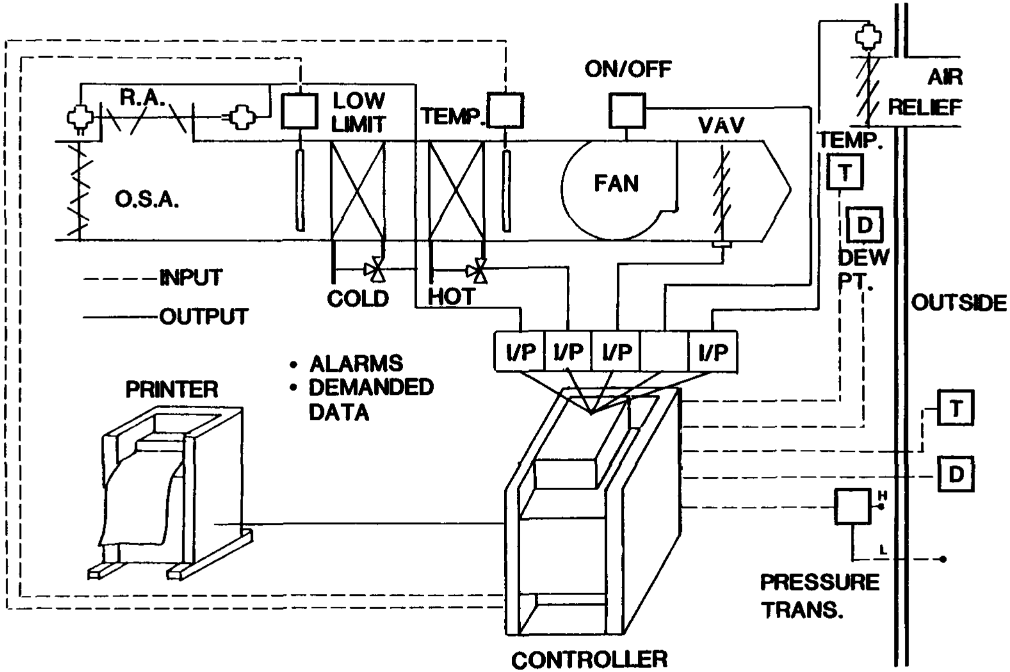


FIGURE 1

°Operate the plant based on requirements in the buildings.
°Operate at peak efficiency taking advantage of the outside environment and the characteristics of the equipment being controlled.

Generally, this simply means that feedback is required from the buildings so that actions can be taken to raise chill water supply temperature, lower boiler water supply temperature, lower cooling tower water temperature and turn equipment off when not needed. The following "figure 2" illustrates such a system.

The task can become more complicated with evaporative cooling, heat pumps, electric generators and other techniques. This makes the argument for selecting a controller which is expandable.

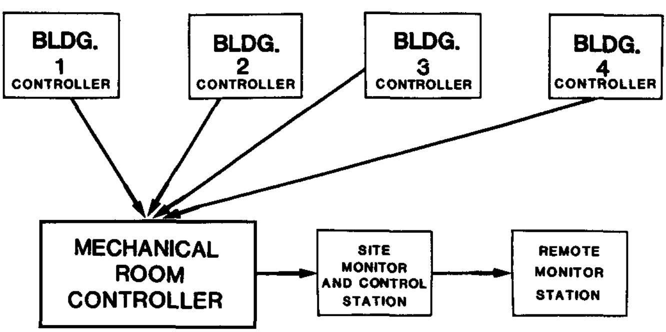
3.8 <u>°Level 6 - Site Monitor and Control Station</u>

A site monitor and control station are usually a necessary feature of an energy control system. The primary function of the station is to monitor the operation of the controller across the site.

Usually, the building controller can be reprogramed from the station, but real time control by the station is not generally a good idea because the complete site is lost if the station fails. Management reports are an important function of the station.

3.9 <u>°Level 7 - Telecommunications</u>

Telecommunications can be a very valuable feature to a corporation or management company responsible for the energy costs of several sites. The technology is readily available and relatively inexpensive to incorporate. The figure below illustrates these concepts.



MECHANICAL ROOM CONTROL

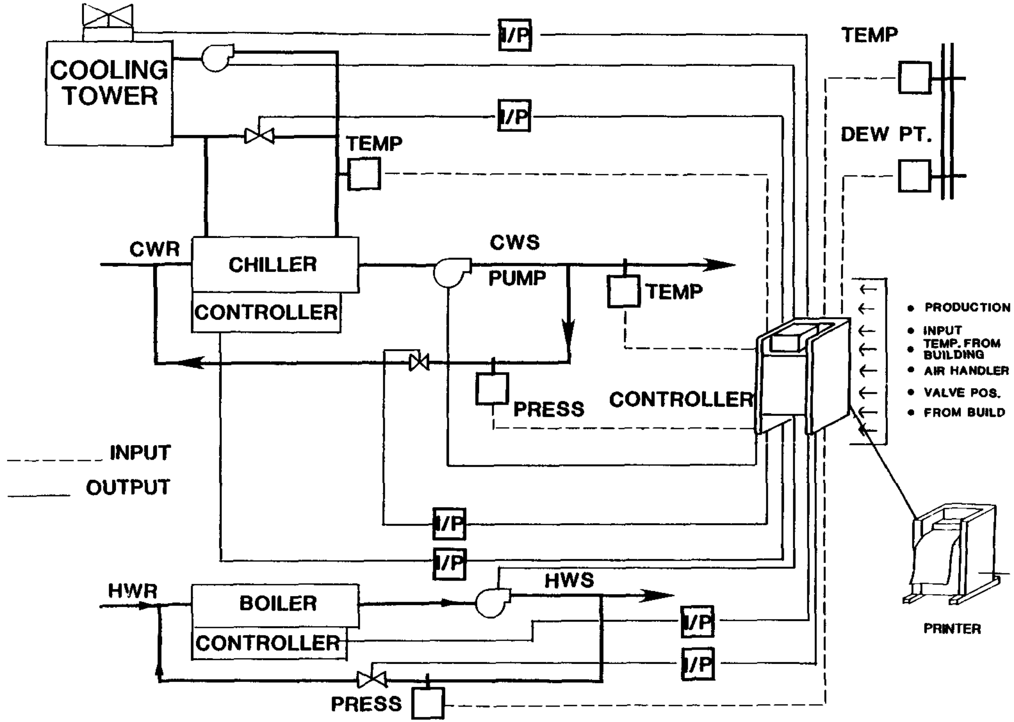


FIGURE 2

Conclusions

The following figure illustrates the decisions to be made in selecting an energy control system for a central cooling/heating facility.

Decision A →	Decision B →	Decision C →	Decision D
1. Manual or 2. Computer Control	Levels of control to be incorporated 1. On/off 2. Demand 3. HVAC 4. Production 5. Mech. Room 6. Site station 7. Telecommunications	1. Central computer vs. 2. Decentralized control	HVAC controls 1. Pneumatic 2. Reset pneumatic 3. Modulated pneumatic 4. Close Loop - pneumatic 5. Close Loop - electric

The discussion above has been very brief, but hopefully provides a guide for those considering an Energy Control System.

CONSIDERATIONS FOR CENTRALIZED EMS SYSTEM CONTROL

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I. INTRODUCTION

As many large companies add energy management systems to their facilities, a strong need exists to determine if the conservation techniques are effective and are providing savings. In many companies this is accomplished by examining utility bills, a procedure involving manual computation and analysis yielding results that may be three months out of date. For large retail chains, the paperwork becomes overwhelming. One solution to this problem is to automate the gathering and analysis of data from remote systems.

Planning for a centralized EMS control system should take into account many factors. Each remote site must have some form of communications link to the central site. The communications system at the central site must be sized to prevent backlogging at the central computer. Careful consideration must also be given to the division of intelligence between remote systems and the central site, since intelligence at a remote unit can substantially reduce the communications burden and simplify the analysis of data at the central site.

This paper contains a description of a large central computer control system designed to communicate with energy management equipment from a variety of vendors installed in facilities ranging from small stores to multi-building complexes. Discussions of problems encountered in this approach to central control and the solutions devised to overcome many of these problems are also discussed. The major focus is a logical structure for the implementation of a sophisticated central control system.

II. PROBLEMS AND SOLUTIONS

The design of a centralized computer system is determined by the type of equipment and control strategies being used for energy management control and the types of analysis, reporting, and interaction required by the control center's operators and managers. The major problems encountered with designing a single computer system to handle this complex task and, where applicable, the solutions to those problems are described below:

A. Non-communications Controllers
Any energy management system without communications capability, whether local or remote, prohibits monitoring or altering the operation of the EMS unit from a central computer. Depending on the design of the EMS unit and the data required at the central site, an outboard microprocessor-based communications device may be used. We will refer to this device and others like it as a "Black Box". A Black Box typically provides demand, consumption, and temperature data to the central unit. The Black Box could also provide intelligent alarming capabilities (high or low temperature, high demand, etc.).

B. Simple Energy Management Controllers
These units perform basic time-of-day scheduling and duty cycling; some units also provide for demand limiting (load shedding) and typically can control 8 to 16 loads. Data available from these units may be limited to current demand and consumption (no historical data). This limitation means that the central computer must interrogate the unit frequently to develop an accurate profile of the energy consumption patterns of a facility. Again, a Black Box may be used to provide additional information. A Black Box may be attached between the EMS unit and its communications cable, allowing the Black Box to interrogate the EMS unit on a periodic basis, say hourly, and accummulate data on an hourly, daily, or other basis. The accummulated data can then be retrieved by the central computer less frequently than would be permissable without

the Black Box.

C. "Dumb CRT" Communications

The two basic types of communications protocol are the "Dumb CRT" protocol and the "Block Structured" protocol. A "Dumb CRT" protocol involves the use of a CRT or terminal as the communications device with the EMS unit. This protocol requires that the EMS unit format its output in a manner readable by the operator at the terminal. No error checking can be performed on the data transmitted because the EMS unit assumes the terminal device has no intelligence.

A "Block Structured" protocol makes use of a computer as the communications device. Data is transmitted in blocks in the EMS unit's internal format, and error check codes are appended to each block. Some form of "handshaking" is used between the EMS unit and the central computer to verify that each block was received correctly. EMS units that support only a "Dumb CRT" protocol are not adequate for centralized monitoring and control. Such units complicate communications with the computer, and the lack of transmission error checking jeopardizes the reliability of the data.

D. Duty Cycling

This strategy is used to prevent all loads in a group from being on at a given time. Each load in the group has an ON-TIME, and OFF-TIME, and a START-TIME. By making the ON-TIME and OFF-TIME the same for each load and staggering the START-TIME, one or more loads are guaranteed to be OFF at any time. Not all energy management systems require or check for staggered START-TIME. It is possible through errors in programming an EMS unit that all loads may be ON at once.

The best way to prevent incorrectly configured duty cycles is to provide program validity checking and simulation at the central location. Potential conflicts within a duty cycle or between duty cycles may then be identified and corrected before a control program is downloaded to an EMS unit.

E. Ladder Logic

Most programmable controllers (PC's) use ladder logic for representing the internal programming and external interface for the unit. Unfortunately, ladder logic diagrams do not provide a clear picture of the control strategy for a facility, nor are they safe to modify unless the person making the change is familiar with a unit's entire program. Changing an entry in one portion of the logic may affect other portions of the logic. Several things may be done at the central computer to reduce these problems.

For one thing, initial programming of a PC should be in a form that fits the application rather than the PC. For most energy management applications the first level of programming is for time-of-day schedules and duty cycles. By allowing the operator to enter the information for schedules and duty cycles in a tabular form and then compiling this information into ladder logic, the central computer provides the operator with a simple tool for starting his programming and prevents some of the errors that might be introduced by programming directly in ladder logic.

A far more difficult task for the central computer is to read in PC's programming and convert that back to a tabular form. The most practical alternative is to provide the operator with two levels of programming. The first level would be that described above, a tabular format for defining time schedules, duty cycles, and other basic control information. A compiler would generate standard ladder logic from this tabular information. The second level of programming would allow the operator to program a PC in ladder logic directly. This would allow the operator to add special control logic or to modify the previously generated logic from the first level for special cases.

As was discussed in the section on duty cycles, program validation and simulation prior to downloading are also important aids. In the case of PC's, these aids become even more crucial because of the difficulty in detecting errors or operational problems except through "trial by fire".

III. CENTRAL SYSTEM ORGANIZATION

The hardware used to implement the central control system may be divided into five logically distinct groups: communications, operator interface, data storage, peripheral devices, and auxiliary processing. In a microcomputer-based configuration, each of these groups may consist of one or more microprocessors. We will refer to each group of microprocessors as a service processor. Each service processor controls the equipment attached to it. All of the service processors communicate through an internal communications link to a central service processor, which acts as a "traffic cop". The central service processor controls communications between individual service processors. It also controls access to both online disk storage and offline tape storage (see Figure 1).

The individual service processors perform the functions described below:

A. <u>Communication Service Processor</u>
This processor is responsible for handling communications between the central computer and remote EMS units. Since the protocols vary from vendor to vendor, this processor removes the protocol information from incoming messages and adds the appropriate protocol information to outgoing messages. Several communications may be in progress at any given time, some of them originated by the central computer, with others being the result of incoming calls.

B. <u>Operator Service Processor</u>
The operator service processor provides the interface to the users of the system. Each operator's console contains a keyboard, an alphanumeric display, and a graphics display. Since each console provides the same functional capabilities, this service processor keeps track of what other tasks are currently being performed on behalf of each console.

C. <u>Peripheral Service Processor</u>
This processor controls the operation of printers, plotters, and other output devices which may be attached to the central computer. As requests are made to generate reports or plots, output is sent to the peripheral service processor for a specific device. The processor queues output for slow devices, allowing the task or processor that generates the output to proceed with other jobs. Additionally, this processor allows for routing of output.

D. <u>Auxiliary Service Processors</u>
Through the use of auxiliary service processors, computation-bound jobs may be offloaded from main processing. An example of a good use of an auxiliary service processor follows:

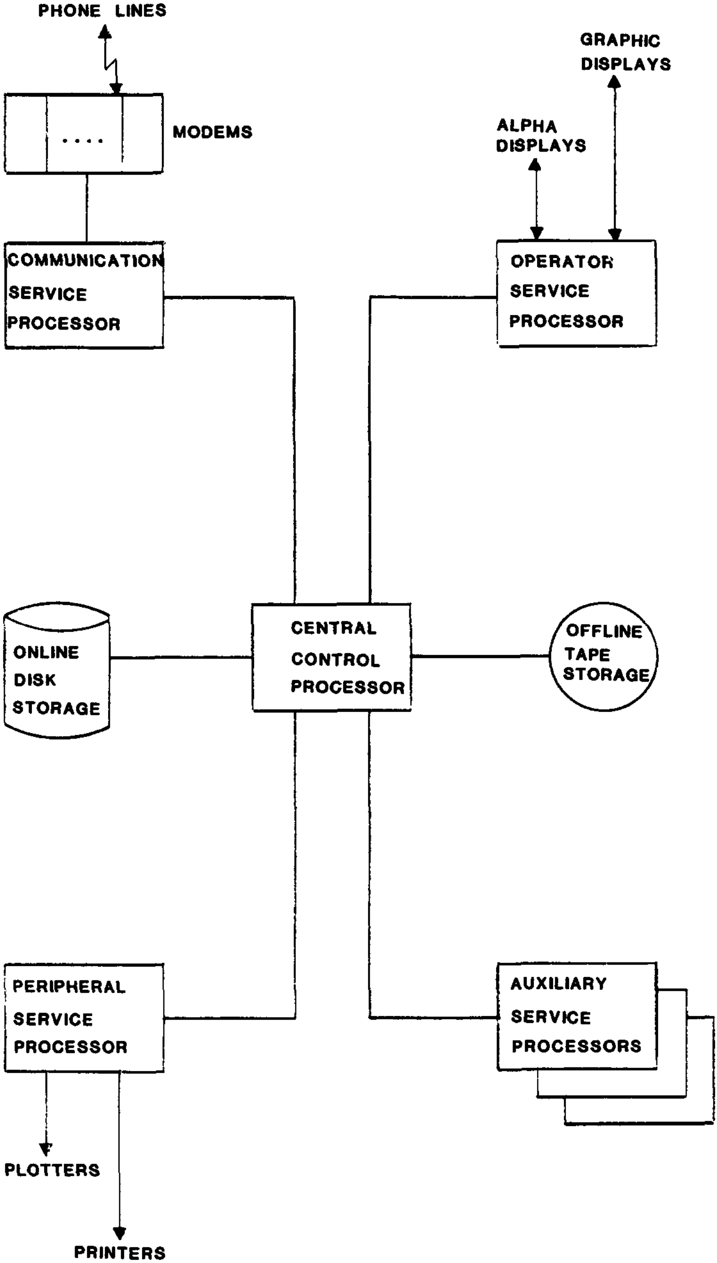

FIGURE 1: CENTRAL SYSTEM CONFIGURATION

A report has been requested by a console operator. The report requires that the mean and standard deviation be computed for the daily demand and consumption of an EMS unit for the past 12 months. Not all of the data required may be present in online data sorage, requiring one or more requests for a temporary load of offline data. Because of the offline data storage, this job may have taken many minutes to complete, during which the requesting console would be available for other requests since the report is being handled by an auxiliary service processor.

The software for the central computer is divided into two major categories: foreground and background. One software component which straddles the categories is the master control module. It is responsible for coordinating all activity within the central computer (see Figure 2). Although a particular software module generally executes in a specific category, the master control module may offload a foreground routine to background operation, as in the example just above.

Although the individual software modules involved in a central computer are too numerous to discuss, there are several functions which are important to the successful operation of a central monitoring and control facility:

A. Alarm Monitoring
The ability to recognize and respond to alarms generated by remote EMS units is a central part of a stratey of energy management by exception. Particularly in a central system responsible for hundreds of remote EMS units, alarm monitoring reduces the possibility of serious problems going unnoticed.

B. Anomaly Detection
Even when alarm monitoring is a part of the central control system, many problems may occur in a facility which do not raise an alarm. Broken fanbelts, clogged coils, worn bearings, and multitude of other maintenance problems can affect the energy savings of a facility. By analyzing the data retrieved from units, facilities with potential maintenance problems may be flagged. Some of the checks which could be performed on data are:

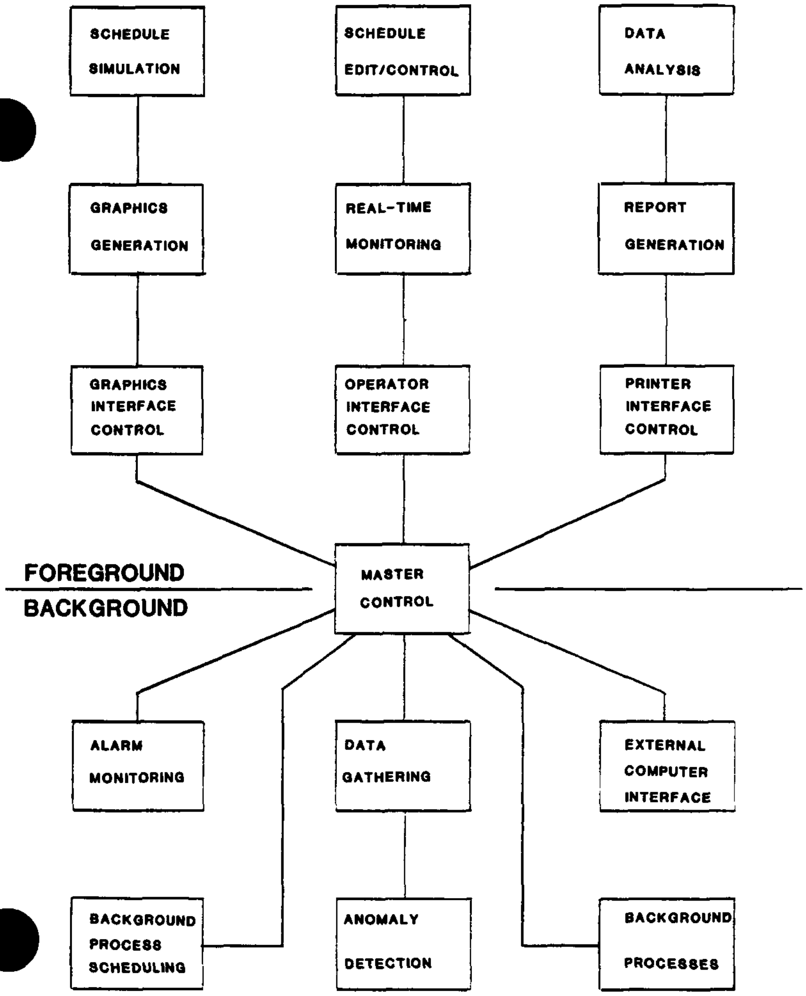

FIGURE 2: FUNCTIONAL SOFTWARE ORGANIZATION

1. A sudden increase in peak demand or consumption, without a significant change in outdoor air temperature.
2. A steady increase over a period of time in peak demand or consumption.
3. A change in average zone temperature, indicating an inability to maintain normal conditions.

C. Program Validity Checking and Load Simulation
As previously mentioned, program validity checking prior to downloading to remote EMS units is extremely important, even if only to reduce embarassment. Energy management programs with either design or typographical errors can create occupant discomfort and may actually increase peak demand and consumption. Basic validity checking is only a first step. To truly appreciate the effects of a particular control strategy, a load simulation should be performed, yielding a demand and consumption profile. Load simulation has a further value in future fine-tuning or strategy changes, which can be performed in the safety of a computer, rather than using the facility as a guinea pig.

The hardware and software organization described above provides the backbone for a central control system with the ability to grow as requirements change. Additional hardware may be attached to the current service processors. New service processors may be added when current processorors become fully loaded or as new functions are defined. As new pieces of EMS equipment are installed in the field, software modules may be added for communication, programming, monitoring, and control. Individual software modules may be enhanced without impacting the operation of the remainder of the system.

In summary, two major points should be kept in mind when planning a central computer system. First, the hardware and software must be modular to allow for expansion and change. Second, the requirements for energy management in facilities should dictate the functions of the central system, not the other way around.

PRACTICAL ASPECTS OF INTERFACING AN EMS TO NEW AND EXISTING FACILITIES

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I. INTRODUCTION

The benefits to be realized from an investment in an Energy Management System have come under close scrutiny in the past year. We hear of great successes and we also hear of some that are not so great. The variable nature of these reports suggest that there are some practical realities that are sometimes overlooked in both the selection and the application of an EMS to the facilities controlled.

The mere fact that there are successful applications is a strong indication that every facility of reasonable size will have an EMS. The decisions thus become, when, what kind, and how it can best be used.

The rapid growth of computer and micro-processor technology has created a tremendous potential in the control of processes such as HVAC and energy management. In fact, the capability of computers to gather data and make decisions now exceeds the ability of the hardware at the control point to carry out those decisions. Our knowledge of how to effectively use an EMS computer is also lagging behind the technology.

The intent of this discussion is to review some of the factors in the selection and application of an EMS that will influence its effective use.

II. SYSTEM CONFIGURATION

In selecting an EMS, the type of equipment, amount of memory, software, display methods, and the system configuration will ultimately be determined by the nature and size of your facility. The choi are many and you will hear some guidelines today t may help in your selection.

The system configuration you select is quite important. In some of the first EMS systems, most of the work of processing data and issuing commands was done by the central or host computer. This created some rather complex timing and communication problems. It also placed all of the eggs in one basket. If the host failed, everything failed! With the availability of suitable micro-processors at a reasonable cost, the trend is toward distributed processing, or placing more of the work near the point of control. Today, it is common to employ several levels of logic processing.

In an ideal situation, the building or controlled system should operate totally independent of the host computer under normal conditions. The host should only become involved when an abnormal condition arises, or when it is necessary to alter the system's operating parameters. This is true "stand-alone" control. The control logic resides in one or more local processors with their own memory which will store instructions and parameters down-loaded from the host.

Another possible configuration, which we will call "semi-stand-alone", requires the host to issue periodic commands such as daily startups and shut-downs and to perform some of the more complex calculations. If for some reason the host command is not received on schedule, then a fall-back or default command resident in the building or local processor would be used. This can be a satisfactory mode of operation, and can reduce the complexity of the fi processor.

The term "stand-alone" has also been used to describe a configuration having a conventional pneumatic or electronic temperature control system which can function with or without connection to an EMS or central computer. On the surface, this sounds like a rather safe and sure approach, and it is attractive when connecting to existing facilities that already have some form of control system. In new construction, however, it is the most expensive approach. It also provides the least control flexibility in both new and existing facilities since must of the control logic resides in controllers that must be adjusted manually with a screwdriver or a dial. There are also many problems in interfacing due to the different types and ranges of the control signals used.

From an energy management standpoint this is the least desirable type of system and offers the lowest return on investment. In some cases, however, there may be a significant benefit in just being able to monitor the real-time status of a system and in knowing the amount of energy being used. This can help to identify inefficiencies that may be brought in line by system changes.

III. INTERFACING PROBLEMS

It was mentioned earlier there are some practical realities that may be often overlooked in the selection and application of an EMS. Heating, ventilation and air conditioning, or HVAC, is usually the principal process controlled by an EMS. Most of the following comments are thus directed to HVAC systems.

A. REALITY #1. ANY EQUIPMENT, DEVICE OR COMPONENT CAN AND WILL FAIL

In considering any EMS, examine the failure modes at all levels. The host computer...peripherals...communications controller...trunk cables and modems...field controllers...sub-processors...control relays...actuators...sensors... etc. Understand what recovery options you will have and evaluate the risk to your particular operation. This analysis will enable you to determine the degree of redundancy required to meet your requirements.

A very simple item that can be easily overlooked is a local switch that can be used to start a fan or pump motor and bypass the automatic controls. Most motor control centers are equipped with hand-off-auto switches which should perform this function. There may, however, be other functions slaved to the normal control relay that will not be activated by the H-O-A switch, such as opening a damper.

The power failure and restart sequence should be examined closely. Will all motors start together when power is retored? Will they start at all unless reset manually?

B. REALITY #2. COMPUTERS ONLY CARRY OUT INSTRUCTIONS

The control logic for any system must still be originated by people. The results obtained will only be as good as your ability to define the instructions. You will probably not be satisfied with the first try. One of the big advantages of a true stand-alone system is the ease in modifying logic statements and fine tuning a systems operation.

C. REALITY #3. THE LACK OF A CONTROL POINT OR SENSOR WILL DEFEAT ANY LOGIC

Being over-conservative when specifying control points and sensors is not the best way to save cost. The physical location of sensors can also greatly effect the success of control logic. Not having control of a damper or having the wrong type of valve will also defeat it.

D. REALITY #4. HVAC SYSTEMS ARE NOT NORMALLY DESIGNED FOR EMS CONTROL

Due to the competitive bidding process we all experience in contracting for facilities, too little emphasis is placed on operating and maintenance cost. Much of the responsibility for this situation is our own fault as energy engineers. We have not done an adequate job of helping to educate facility and mechanical designers nor have we provided enough guidance during the specification phase. We also need to provide our management with cost vs. payback information on more of the techniques that are available.

An excellent case in point is the use of variable speed drives for fan motors. A typical 50 horsepower motor, running 12 hours a day, five days a week, costs about $12,000 per year to operate. In a damper controlled system very little can be shaved from the full load current. With a variable speed drive, the potential savings can pay back the difference in initial cost in less than two years by most estimates, yet they are seldom specified as a requirement due to the higher initial cost.

There are some areas that do not yet have ready hardware solutions. Variable air volume boxes have received a lot of attention lately. They offer a solution to some zone control problems; however, most are not easily connected to an EMS. Certainly the hardware manufacturers will meet the demand when it is recognized. In the meantime, we must continue to use actuators and control devices that were designed for conventional systems.

The interface to package HVAC units is also rather difficult. They come equipped with their own control logic which you often pay for whether you use it or not. The suppliers are also quick to point out that they cannot guarantee the unit if you do not use the built-in controls. This type of unit is also sold in a very competitive market and they are designed to satisfy the average need of any climate. It would seem that the manufacturers would be well advised to offer units for remote computer control and provide the necessary instructions to protect the warranty.

One further comment about the design process. Based on a Requirement Specification, the A&E mechanical designer determines the air flow and water flow, lays out the duct system, and defines the entire system. Then he calls in a controls engineers to make it work. This engineer is usually employed by a company that makes or sells controls. Naturally he is going to use the components that he is most familiar with... the ones his company sells. Yes, there may be an "or equal" note somewhere on the call-outs, but changes seldom occur. If EMS control is not specified and his company doesn't happen to sell EMS systems, the odds are great that future interfacing to an EMS will be complex.

We must find a way to have an unbiased controls engineer work with the mechanical designer in laying out the system.

We must also do a better job of communicating our objectives by means of specifications and standards.

E. REALITY #5. RESISTANCE TO CHANGE IS A SIGNIFICANT FACTOR

This is the last of my practical messages, but no less important than selecting the right EMS system. The people who service and operate HVAC systems are the ones usually expected to resist change the strongest, but engineers can be pretty stubborn and set in our ways too. Regardless of the function, it need not be a lasting problem if it is recognized and dealt with actively. No one will resist a new way if they feel comfortable with it and believe it will make their job easier, and if they have an opportunity to contribute their ideas and are trained adequately.

IV. CONCLUSION

We are being made more aware every day of the increasing part that computers are going to play in our lives. We are all resisting this change to some extent. Instead of being a feature that we optionally add to a building to monitor and control energy, computers will soon become an integral part of our facility designs and will perform a wide spectrum of functions. Our task is to learn to apply them in the most effective manner.

THE BUILDING ENERGY EFFICIENCY PROJECT: A PRIVATE SECTOR RESPONSE TO THE OPPORTUNITIES FOR INCREASED BUILDING ENERGY EFFICIENCY

Charles E. Schaffner
Executive Vice President
Syska & Hennessy, Inc.

John Tato, II
Vice President
Haufler, Inc.

Part I: Project Overview

This paper is the first of three presentations on the Building Energy Efficiency Project of the National Institute of Building Sciences. Its purpose is to acquaint you with the rationale of the project, the scope of work and the approach to its performance, and the current status of the effort.

The nation's 83 million residential units and 4 million non-residential buildings consume one-third of the total energy used by the U.S. at a cost of more than $100 billion per year. At the same time, there is common agreement that at today's prices and with available technology, substantial, cost effective increases in building energy efficiency are possible. Increased investment in energy efficiency improvements can save consumers billions of dollars in reduced energy costs while providing jobs for thousands of workers in the economically depressed building industry.

However, even with the impetus of escalating energy prices, the nation as a whole has been slow in responding to these opportunities. Also, because of specific barriers, progress in certain segments of the market will continue to be slow.

Past public and private sector efforts to respond to this situation have met with only limited success, and new government initiatives in this area are unlikely. The Building Energy Efficiency Project intends to fill this void. In a comprehensive and systematic fashion it is focusing the resources of the building community on improving building energy efficiency through new business opportunities.

Through the National Institute of Building Sciences, the project is proceeding in two phases.

A strategy development period, currently in progress, in which the creativity and expertise of the private building community is being used to identify the economic potential for energy efficiency improvements, to determine the barriers to the achievement of this potential, and to develop the means of eliminating these constraints.

An implementation phase in which specific programs will be undertaken by the building community to increase the market for energy efficiency products and services.

The Building Energy Efficiency Project is distinguished from previous initiatives in that it is --

a product of the building community--not a government program;

oriented to the economic self-interest of building owners and the construction community--not built on regulation;

a practical agenda for action--not another theoretical study of the building energy issue;

based on real and current experience--what works and pays for itself; and

an integration of all energy technologies and building types--not narrowly focused on particular aspects of building energy use.

The overall objective of the program is to encourage the economic use of energy in the nation's existing buildings. At the same time, the program seeks to preserve maximum freedom of choice regarding the levels of energy efficiency to be attained and the means of attaining those levels.

The intention is to complement existing market forces in creating opportunities for increased building energy efficiency. Further, the project will reinforce and encourage other energy programs with similar objectives.

In meeting these goals, the project is relying predominantly on voluntary efforts and is emphasizing cooperation between the public and private sectors cf the building community. Further, only cost effective measures will be pursued.

In order to be broad and balanced, the project has addressed --

the nation's entire stock of existing residential, commercial, institutional and industrial buildings;

the interests of all owners and users of buildings, including tenants; and

all end uses of energy in buildings, except industrial and other processes that are not typically related to building services and functions.

The project will produce --

a comprehensive assessment of the market for building energy efficiency services and products;

programs aimed at increasing the rate and magnitude of investment in building energy efficiency; and

increased investment through implementation of these building community programs.

The strategy development phase of the program consists of the following four tasks:

subdividing the existing building stock into discrete market segments;

targeting the most promising opportunities for increased energy efficiency, ie. those circumstances with high potential for greater efficiency but little action under current market conditions;

developing innovative approaches for realizing the targeted opportunities through detailed assessments of the factors which shape these market segments; and

combining these approaches into programs and projects for action by the building community.

<u>Segmentation</u>: The purposes of this initial task in the strategy development is to:

establish a framework for compiling and analyzing the substantial body of information on building energy use;

highlight the greatest opportunities for near term gains in efficiency; and

provide the basis for building community consensus on an overall strategy for increasing building energy efficiency.

Targeting: This step consists of comparative analyses of the market segments. Its purpose is to determine the focus of subsequent project activities through the identification of the most promising opportunities for increasing building energy efficiency.

The selected method of targeting market segments is based on the following two key elements of the program's mission:

achieving maximum near term reductions in expenditures on energy; and

complementing existing market forces and building energy programs.

With the foregoing points in mind, the targeting step has consisted of compiling basic data on each building type and developing estimates of the potential and likely reductions in energy use that either could or will occur in the next 5 years. The difference or gap between what reductions in energy use could be economically justified and what reductions can be expected to occur under current conditions, is being used to determine which market segments will be the subject of further investigation.

Segment Analysis: In this step, the segments targeted for the development of programs and strategies will be analyzed in detail. These analyses will define each segment in the following terms.

the relevant energy conservation techniques;

the decisionmakers who will determine the extent to which energy efficiency improvements will be made; and

the economic and other factors which both encourage and discourage investments in energy efficiency improvements.

Unlike the segmentation and targeting activities which depended predominantly on secondary sources of information, this task will involve detailed research, interviews, and surveys of product manufacturers, utilities, contractors, designers, building users, and others. Further, the work will be performed by committees of building community experts who possess in-depth knowledge of the subject market segments.

This research and analysis effort will require the most time and the greatest level of effort of all strategy development activities. It will result in a series of analyses or "segment strategies" recommending actions that can be taken to increase energy efficiency within each targeted segment. Recommended actions could include, for example, the following:

research and development or the demonstration of particular energy efficiency technologies;

educational efforts aimed at particular decisionmakers; and

various market development efforts aimed at eliminating barriers to or providing incentives for increased investment in energy efficiency improvements.

Each segment strategy will be described in sufficient detail to identify the specific actions that should be taken and the roles of key participants.

Program Integration: As the final step in the strategy development, this task will integrate the individual segment strategies into a comprehensive program of action for the building community.

The overall program will be derived from grouping the segment strategies according to one or more of the following dimensions.

the technologies involved in the recommended activities;

the decisionmakers affected by the recommended activities; and

the decision factors and barriers at which the actions are aimed.

The character of the activities included in a program will depend upon its orientation. For example, if a program is aimed predominantly at barriers, its activities may focus on information and incentives. In turn, the types of activities included in a program will determine the source of its long term support and what groups should be involved in it on a continuing basis. Finally, the mix of programs that constitute the overall strategy will determine the most appropriate organizational form of the project in its implementation phase.

The ambition of the project is to move as quickly as possible into implementation following strategy development. In fact, to the extent that a consensus is reached on the desirability of initiating specific projects, implementation activities may begin before the overall strategy is completed. In addition, from the outset of the project, activities have been undertaken to facilitate the sharing of information and to promote on-going programs.

The project organization for the strategy development phase has consisted of the following three elements.

The Sponsors Council;

Project Committee; and

Staff and Consultants.

The Sponsors Council is a small group representing the financial supporters of the project. In essence it is the client for the strategy development and performs the following functions.

Evaluating and commenting on the research effort;

Recommending priorities for study;

Participating in developing the segment strategies and integrating them into an overall program; and

Providing recommendations on the program to the Institute.

By virtue of their positions or professional stature, the members of the Sponsors Council have the ability to effectively promote the project within the building community. Further, through training and experience, they possess an overview of building energy issues and the structure of the building community.

Presently, the project has 26 sponsors. Drawn predominantly from the private building community, its supporters include major product manufacturers, trade associations, professional societies, and design firms. Also several Federal agencies have provided financial support.

A project committee of over 135 members has been formed from the Institute's membership, including representatives of the project's financial sponsors. It serves as the basic technical resource to the project and insures that all of the pertinent interests within the building community have the opportunity to participate in the project. It also assures that all deliberations are open and balanced and that any gaps in representation are identified and filled. Finally, the committee reports the progress and results of the work to the Institute. As with all Institute work, final authority for the project resides with the Institute's Board of Directors. Finally, staff and consultants provide administrative support to the activities of the Sponsors Council and the project committee and conduct specific research and analyses in support of the project.

The original budget for the project was $370,000. To date, approximately $100,000 has been raised and additional funds are being sought to complete the strategy development. Eleven months were allotted to complete the initial phase of work. Based on the experience with the segmentation and targeting activities, this estimate has been increased to 16 months.

Part II: Progress To Date

The project is currently at the midpoint of the strategy development, ie. the segmentation and targeting activities have been completed and the detailed segment analyses have begun. Following is a summary of the work that has been performed.

It was initially proposed to segment building energy use by building type, eg. offices and schools, and energy end use, eg. space heating and domestic water heating. This approach suggested the matrix depicted in figure 1. Each combination of building type/end use corresponds to a portion of the total energy used by the existing building stock. As a whole, the 90 cells of the matrix account for all energy used in buildings.

The decision to segment the existing building stock on the basis of building type and energy end use was reached after evaluating several alternative bases for subdividing the stock. Among the factors considered were fuels used, barriers to increased energy efficiency, geography, and applicable energy conservation techniques. Each possibility was evaluated against the following criteria:

the method should make maximum use of existing data;

it should be compatible with the definitions used in other building energy programs thereby fostering mutually beneficial links with these programs; and

the method should account for all building energy use.

Several building types and energy end uses were eliminated from further analysis because they account for very little energy use, are typically beyond the control of the building community, or there is insufficient data to permit their evaluation. Specifically, the following building

BUILDING TYPE/ENERGY END USE MATRIX

FIGURE 1

	Space Heating	Space Cooling	DHW	Lighting	Appliances	Other	
Single Family Detached							29%
Single Family Attached							2%
2-4 Unit							5%
Multifamily							3%
Retail/Service							16%
Office							11%
Education							8%
Health							3%
Public							8%
Lodging							5%
Warehouse							4%
Automotive							1%
Religious							2%
Other Commercial							2%
Mobile Home							2%
	51	14	7	15	10	3	100%

types and energy end uses were eliminated.

Building Types

-- mobile homes
-- warehouses
-- automotive
-- religious
-- other commercial

Energy End Uses

-- appliances
-- other

The remaining matrix of building types and energy end uses accounts for 75 percent of the energy used in existing buildings.

At approximately this point in the work, the report Energy Efficiency of Buildings in Cities, prepared by the Office of Technology Assessment (OTA) of the US Congress, became available. Because this report was current and provided a detailed assessment of the building retrofit market, its relevance to the project was evaluated in depth.

It was concluded that the results of the OTA report could not be substituted for the segmenting and targeting activities of the Building Energy Efficiency Project. However, the segmentation strategy used by OTA varies considerably from the Institute's approach, which suggested the need to reevaluate the decision to segment on the basis of building type and energy end use.

In its study, OTA concludes that the following four factors have the greatest impact on the retrofit potential of existing buildings:

Size;

Wall and roof type;

Mechanical system (HVAC) type; and

building purpose.

For each of the foregoing factors, OTA identifies two or more conditions, as follows:

Size-small and moderate or large;

Wall and roof type-frame or clad walls and masonry;

Mechanical system type --

-- central air system,
-- central water,
-- complex reheat system, and

-- decentralized system;

building purpose--single family or 2-4 units, multi-family and commercial.

Because of the significant differences between the Institute's approach and the one used by OTA, it was concluded that the appropriate next step was to identify as many factors as possible which could influence either (1) potential energy savings[1] or (2) the level of savings that are likely to occur under current market conditions.

This effort resulted in the following list which is presented in two parts. The first consists of "stock" variables which relate to the physical characteristics of a market segment in terms of the buildings which constitute the segment. These factors are more likely to influence potential savings. The second part of the list relates to factors which should affect likely savings and which have therefore been entitled "market" variables.

Stock Variables

-- number of buildings
-- total square footage
-- geographic location
-- size
-- age
-- configuration
-- type of construction
-- energy end uses
-- energy demand profile
-- fuel types
-- mechanical system type

Market Variables

-- owner type
-- owner occupancy
-- professional buildings management
-- lease terms
-- responsibility for energy costs
-- building use
-- business climate
-- programs and incentives
-- barriers
-- investment criteria
-- energy cost

Concurrently with the identification of the stock and market variables, the building types were divided into

---

(1) Potential energy savings are defined as the reduction in current energy use that would result from the installation of all "cost effective" conservation measures.

five categories for evaluation. The rationale was that several individual building types share similar characteristics with respect to key variables and therefore could be grouped together as follows:

Low Density Residential--single family detached and attached units and buildings containing from 2 to 4 dwelling units;

High Density Residential--multi-family residential buildings containing 5 or more units;

Lodging Buildings--hotels, motels and nursing homes;

Institutional Buildings--educational, health care and public service buildings; and

Commercial Buildings--office, retail, and food sales buildings and restaurants.

Further, it was anticipated that questionnaires would be developed to obtain the input of the building community and that the groupings would reduce the number of individual survey instruments and separate mailing lists.

The next task was to evaluate the foregoing "stock" and "market" factors in the context of each building type grouping. The following questions were asked about each factor.

Is data on the factor available?

Does the factor vary significantly within the building type grouping? For example, how much variation is there in investment criteria within the commercial building grouping?

How significant is the factor's impact on either or both potential and likely energy savings?

How significant is the factor's impact on the applicability of specific energy conservation measures?

The ambition of the analysis was to identify the two most significant factors per building type grouping for which data was available. One would be selected because it should have a significant impact on potential savings, while the other would be chosen because of the significance of its impact on likely energy savings.

The evaluation of the factors was performed pursuant to several ground rules. First, if no data was available on a specific issue, it was dropped from further consideration. Also, if the data was limited, the factor's priority was diminished. Third, to the extent possible, each factor was evaluated in isolation although it was fully appreciated that the factors are not mutually exclusive. Finally, the analysis was understood to be highly qualitative.

In summary, the foregoing analysis resulted in the determination that in lieu of further segmentation on the basis of building type, eg. single family detached, low density residential buildings should be subsegmented on the basis of household income and then further subdivided on the basis of the cost of energy. High density residential buildings have been subsegmented on the basis of how the utilities are metered, ie. either master or tenant metered. Of the factors considered, the foregoing are believed to be the most critical in determining likely energy savings.

In the case of the other building groupings, institutional, commercial, and lodging, the specific building types, eg. education, remained the first choice for segmentation. Finally, energy end use was selected in all instances as the other descriptor of the market segments. The results of the analysis are the 60 market segments described in figure 2.

With a segmentation strategy in place, the next step was to define the market segments in terms of key factors and to develop estimates of the potential and likely reductions in energy use. This task was performed by the principal technical consultant to the project: Booz·Allen & Hamilton. For low and high density residential, institutional, commercial and lodging buildings estimates were developed for the number of buildings in each category. Estimates were also prepared of the gross area of each building type and its energy use and cost. Finally, the percentage of energy used for heating, cooling, lighting and domestic water heating was estimated for each building type.

Using published reports and surveys, current association data, and expert judgement, the consultant also estimated the potential energy savings for each market segment. These estimates are expressed in quads per year and reflect the savings that would result if all cost-effective measures were implemented. Cost-effectiveness is defined in terms simple-payback based on an assessment of the investment criteria of each market segment. Similarly, estimates of likely energy savings were prepared. These estimates reflect the savings that are expected to be achieved in the next five years based on current conditions, ie. the impact of current conservation programs and the impetus of the increased cost of energy.

The consultant's estimates are not presented here, but rather will be included in another paper on the

MARKET SEGMENTS

FIGURE 2

Low Density Residential

Higher Income

High Utility Cost

1. Heating
2. Cooling
3. Lighting
4. Hot Water

Low Utility Cost

5. Heating
6. Cooling
7. Lighting
8. Hot Water

Lower Income

High Utility Cost

9. Heating
10. Cooling
11. Lighting
12. Hot Water

Low Utility Cost

13. Heating
14. Cooling
15. Lighting
16. Hot Water

High Density Residential

Master Metered

17. Heating
18. Cooling
19. Lighting
20. Hot Water

Tenant Metered

21. Heating
22. Cooling
23. Lighting
24. Hot Water

Commercial Buildings

Office

25. Heating
26. Cooling
27. Lighting
28. Hot Water

Retail

29. Heating
30. Cooling
31. Lighting
32. Hot Water

Food Sales

33. Heating
34. Cooling
35. Lighting
36. Hot Water

Restaurants

37. Heating
38. Cooling
39. Lighting
40. Hot Water

Lodging Buildings

Hotels/Motels

41. Heating
42. Cooling
43. Lighting
44. Hot Water

Nursing Homes

45. Heating
46. Cooling
47. Lighting
48. Hot Water

Institutional Buildings

Education

49. Heating
50. Cooling
51. Lighting
52. Hot Water

Health Care

53. Heating
54. Cooling
55. Lighting
56. Hot Water

Public Service

57. Heating
58. Cooling
59. Lighting
60. Hot Water

Building Energy Efficiency Project.

In order to provide a check on the consultant's estimates and to build a consensus among the participants in the project, several surveys were developed. These surveys requested the advice and opinions of building community experts on the potential and likely energy savings for each market segment and on the major deterrents to increased energy efficiency. Also, their thoughts on the types of programs that would encourage increased efficiency were solicited.

Six individual questionnaires were developed. Separate surveys were prepared for low density residential, high density residential, commercial, institutional, lodging and school(Kindergarten through 12th grade) buildings. The surveys were sent to approximately 670 building community experts. Following is a partial list of the experts who received one or more of the questionnaires.

The Energy Committee of the AIA

The following ASHRAE Committees

- -- Energy Management
- -- TC9.6, System Energy Utilization
- -- Energy Conservation in Existing Buildings
  - . 100.2, High Rise Residential
  - . 100.3, Commercial
  - . 100.5, Institutional
  - . 100.6, Public Assembly

Contributors to OTA's Report "Energy Efficiency/ Buildings in Cities"

State Directors, Council of Educational Facilities Planners

Approximately 25 percent of the recipients responded to the questionnaire. Fifty percent of the respondents agreed with the consultant's estimates while fewer than 20 percent disagreed. In the event a respondent disagreed, he or she was requested to provide an estimate of the potential or likely savings. Typically, those who disagreed with a particular estimate were split, ie. both higher and lower, in their estimates of the correct value. In the case of survey for schools(K-12) the recipients were not provided with the consultant's estimates. They were simply requested to provide their own estimates. Figure 3 summarizes the results of the survey in comparison to the consultant's estimates.

Overall, the results of the surveys support the consultant's estimates, with the understanding that the purpose of the segmentation and related analysis was to provide the basis for selecting the market segments that would be the focus of the future project activities. It

RESULTS OF THE SURVEY OF SCHOOLS (K-12)

FIGURE 3

	SURVEY	BA&H ESTIMATE
• POTENTIAL REDUCTION IN ENERGY USE (OVERALL)	20%	20%
• POTENTIAL REDUCTION IN ENERGY USE		
-- HEATING	20%	22%
-- COOLING	12%	18%
-- LIGHTING	15%	15%
-- DOMESTIC HOT WATER	19%	25%
• LIKELY REDUCTION IN ENERGY USE (OVERALL)	10%	12%
• LIKELY REDUCTION IN ENERGY USE		
-- HEATING	11%	15%
-- COOLING	7%	8%
-- LIGHTING	9%	10%
-- DOMESTIC HOT WATER	7%	10%
• GAP (DIFFERENCE BETWEEN POTENTIAL AND LIKELY SAVINGS)		
-- OVERALL	10%	8%
-- HEATING	9%	7%
-- COOLING	5%	10%
-- LIGHTING	6%	5%
-- DOMESTIC HOT WATER	12%	15%

must be kept in mind that the estimates of the potential and likely energy savings are not intended to be definitive projections, supported by exhaustive and expensive research. The plan was to commit a modest level of effort in order to determine the most attractive targets of opportunity and at the same time to build a consensus regarding the future direction of the project.

The results of the consultant's analyses are included in the paper "An Action Plan for Increased Investment in Energy Efficiency Services and Improvements." Also included in that paper is a description of the process which is being followed to select the market segments for which specific programs will be developed.

AN OVERVIEW OF THE COMMERCIAL BUILDING ENERGY RETROFIT MARKET IN THE USA

Michael B. Harrel
Director of Marketing
Honeywell Commercial Division

We who are in the business of selling goods and services to conserve energy are well aware of the potential to save millions of dollars in energy costs in existing buildings. The company I work for has been controlling the energy used in buildings since the early 1900's. It wasn't until the oil embargo of 1974 that we discovered that this experience also qualified us as an energy management company. Today there are approximately a thousand Honeywell salesmen in direct contact with building owners, selling a broad range of Energy Management Systems. The smaller systems provide start-stop programming, duty cycling and power demand. The larger systems provide these functions plus enthalpy or economizer control, efficient chiller control and other sophisticated energy management functions. In addition, they include operator's consoles, printers for alarms and energy reports, and sometimes color CRT's to graphically show energy using system details.

As we all know from various national studies, there [illegible] over 2 million existing commercial buildings, with a total floor area of 27 billion square feet that spend 64 billion dollars annually for electricity and fuel. Yet, when we look at our own and the energy conservation industry's existing commercial building sales over the past 8 or 9 years, we have to admit that the results have been mixed. Less than 5% have invested in Energy Management Systems.

On the plus side, many forward looking owners have made energy conservation investments and are more than willing to recommend such investments to their peers.

For example, St. Lawrence University in upstate New York, using start-stop programs, power demand controls, equipment cycling software, streamlined its HVAC system. This resulted in more than $65,000 in energy cost savings in one year, and the system paid for itself in 11½ months.

Rockwell International's Electronic Systems Groups, a 205-acre, 17-building complex in Anaheim, California, spent $2 million a year to run their HVAC systems. By using certain software modules, $250,000 was saved in the year following the installation of a building management system.

If you were to visit these buildings you would also find they have made sizeable investments in other energy-related items such as high efficiency lighting, new chillers and so on. These owners, and many others like them, had good reasons for buying Energy Management equipment. Some of these were:

1. EMS and other energy conservation strategies were seen as good short-term investments, with fast payback in energy savings.

2. The energy crisis was seen as real and continuing in the long term, resulting in higher future costs and a likelihood of short supplies.

3. Conservation was viewed as being in the national interest, as well as being good for the owner's image both inside and outside his organization.

On the minus side, those many, many owners who were offered EMS saving investment opportunities, and who did not buy systems, also had their reasons.

Typical of these were:

1. Lack of capital funds due to tight money, or high interest rates, or for other reasons.

2. Owners did not feel confident that claimed energy savings could actually be achieved.

3. Many owners who can "pass thru" energy cost increases to tennants or customers, thus removing the financial motivation to make energy conservation investments.

4. The present energy glut that makes it appear that the energy crisis is over.

5. The fact that most building owner's main concern are the functions performed in the building, not the building itself. The owners therefore place a higher priority on other business investments, even though energy improvement investments may show a higher rate of return.

Whether the owners to whom Energy Management Systems were offered bought, or did not buy, it is assumed that a responsible sales engineer or consultant had gone through an orderly process of analyzing the owner's building, and proposed viable energy investment opportunities to him. Let's take a quick look at the steps in this process.

. First, survey the building and its HVAC and lighting systems as required.

. An analysis of the energy use history of the building for the last 2 years must be done.

. Calculations of the savings for EMS functions such as equipment scheduling, power demand, zero energy band, economizer cycles, and so forth must be completed.

. Estimates of the cost of EMS hardware including complete installation and check-out must be made.

. And, a proposal must be prepared for the owner to fully describe the system offered, its cost, an estimate of savings expected, and in some cases, a payback schedule.

Looking at this list of activities, it's pretty obvious that the homework preceding an EMS sale is expensive for the vendor. This sales cost, when added to the cost of an EMS could substantially reduce the payback. The added cost burden for distribution and application is more of a problem on smaller buildings; buildings less than 100,000 square feet. Since more than half of the existing buildings fall in this size category, there are additional problems delivering EMS systems to over 1 million smaller existing buildings. A more efficient way must be found to sell and put EMS into use for all these buildings.

I've outlined a few of the problems that, so far, have prevented maximum penetration of the existing building energy retrofit market. Although I talked about only the Building Management Systems or EMS portion of that market, I'm sure that these same hurdles exist for any suppliers who would like to penetrate that market with other products and services.

What solutions can we in the energy-related industries offer to improve our position in the market and make our offerings more attractive to building owners? I certainly don't have any easy answers to that question, but I will offer some suggestions:

Let's tackle the tight money problem first. Some approaches that have worked include:

. Leasing energy conserving equipment.

. Leasing equipment, and remote operation of systems for the owner over leased lines.

. Direct vendor financing with shared savings.

I believe that we vendors, as well as energy consultants and others, should keep abreast of all of these alternatives so that we can help others, unfamiliar with the pros and cons of various arrangements, to decide which is best for them. Much is going on in this arena today, and we can expect more in the future.

Next, how can we enhance the credibility of energy conservation systems? It's been said that in our industry we could sell a lot more systems if EMS was as easy to understand as insulation. But there is such a great variety of "energy cures" available that owners tend to be confused -- and wary. Here's a few ideas that could help this situation in the short term:

1. Better and clearer Public Relations and advertising by members of all segments of the energy conservation industry.

2. More demonstration projects sponsored or co-sponsored by manufacturers that could increase public awareness of energy-savings potential. There have been such projects in the past, but many have often been aimed at our own industry, rather than to the building owners and managers.

3. Industry cooperation with affinity groups, such as BOMA, APPA, AHA, etc., in training efforts, keeping these groups up-to-date as we continue to improve our offerings.

4. Industry cooperation with consulting engineers. There are relatively few engineers who feel confident in applying sophisticated EMS systems on their own.

I also believe that there are long-term actions that could improve the credibility and acceptance of EMS.

Today, there are no norms for a building owner to refer to so that he can compare his building to other buildings of similar use and type. It is technically possible to establish such norms, which would not be binding in any way on the owner, but which could help guide him in detecting how much energy is being wasted.

Another step that would help is adding energy audit capability to all EM systems. It is easy to provide software for a microprocessor to read the electric and fuel meters, and to track every kilowatt hour and BTU coming in on a monthly or daily basis. This "automatic auditor" would provide feedback to the owner on how well his energy conservation investments are working for him.

Speaking just to our segment of the industry, microprocessors, which are the heart and brains of every EMS, need software to operate. Owners, in general, are suspicious of software. Manufacturers should provide standard, modular software that is thoroughly proven and well-documented. Custom software should be reserved for unusual applications.

Finally, EMS vendors might do well to develop accurate and easy to use computer programs for estimating energy savings that could result from common EMS programs, such as equipment scheduling, night set-back, and so on. This program could do much to speed up the "homework" required for an EMS sale to occur. Our experience with an energy-estimating computer program in use since 1976 has been good, and has been particularly useful for the smaller buildings.

In conclusion, I am optomistic about the energy retrofit marketplace over the next five years. Energy costs will continue to rise, and in the case of EMS, the price of the functions provided will come down, in comparison to energy cost, to improve payback. If we take some of the marketing steps mentioned, customer awareness will improve and those 2,000,000 owners will find our energy retrofit apparatus more attractive to buy and to use.

AN ACTION PLAN FOR INCREASED INVESTMENT IN ENERGY EFFICIENCY SERVICES AND IMPROVEMENTS

Joseph G. O'Grady
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PSE&G Research Corporation

John Tato, II
Vice President
Haufler, Inc.

This paper completes the description of the current status of the Building Energy Efficiency Project of the National Institute of Building Sciences. (See the paper "The Building Energy Efficiency Project: A Private Sector Response to the Opportunities for Increased Building Energy Efficiency" presented by Mr. Charles E. Schaffner for an overview of the project's objectives, scope and approach.) Further, this paper provides a consistent comparison of the energy retrofit potential of the many building types which constitute the existing stock of residential and non-residential buildings.

The primary objective of the initial phase of the project has been to provide the basis for selecting the segments of the existing building stock which are both the most promising opportunities for increased energy efficiency and in need of special attention if these opportunities are to be realized.

As explained in Mr. Schaffner's paper the work began by subdividing the building stock into 60 discrete market segments of building types and energy end uses, eg. education/heating. Further, estimates of the basic characteristics of the building stock have been prepared. Also, in order to highlight the market segments that should be the focus of future project activities, the "gap" between potential and likely energy savings for each segment has been estimated. That is, estimates have been developed of the energy savings that would result if all cost-effective measures were implemented. At the same time, estimates have been made of the savings that are likely to occur over the next five years under current market conditions. The differences between these two estimates for each market segment define the gap that will be used to select the building types and energy end uses for which conservation programs will be developed in the next phase of the work.

Figures 1 and 2 and Tables 1 and 2 summarize several key estimates of the characteristics of the building stock. These estimates have been developed by Booz•Allen & Hamilton which has been the principal consultant on the project. They provide data that will be used in conjunction with the gap between potential and likely energy savings to select the market segments that will be the subject of the next phase of work.

In addition to the spread between likely and potential energy savings, several other factors have been considered for use in narrowing the focus of the project. Among the factors considered were the following:

the size of a market segment in terms of energy use and/or expenditures on energy;

a market segment's energy intensity, ie. energy use per square foot;

the concentration of a segment, ie. the average area of the buildings in the segment; and

energy costs as a percentage of the operating costs for a specific building type.

Qualitative criteria, ie. the "receptivity" of a market segment to programs that would increase the level of investment in energy efficiency improvements, were also considered.

Of the foregoing criteria, it was decided that the magnitude of a market segment's energy use and expenditures on energy should be combined with the gap between likely and potential energy savings in evaluating the market segments for further study. The other quantitative criteria were eliminated because they would require additional research or because they were not judged to be significant. Finally, no qualitative criteria of significance were identified.

Based on the foregoing decision, the following two evaluation criteria have been developed:

Existing Residential Buildings—Energy Use and Cost

FIGURE 1

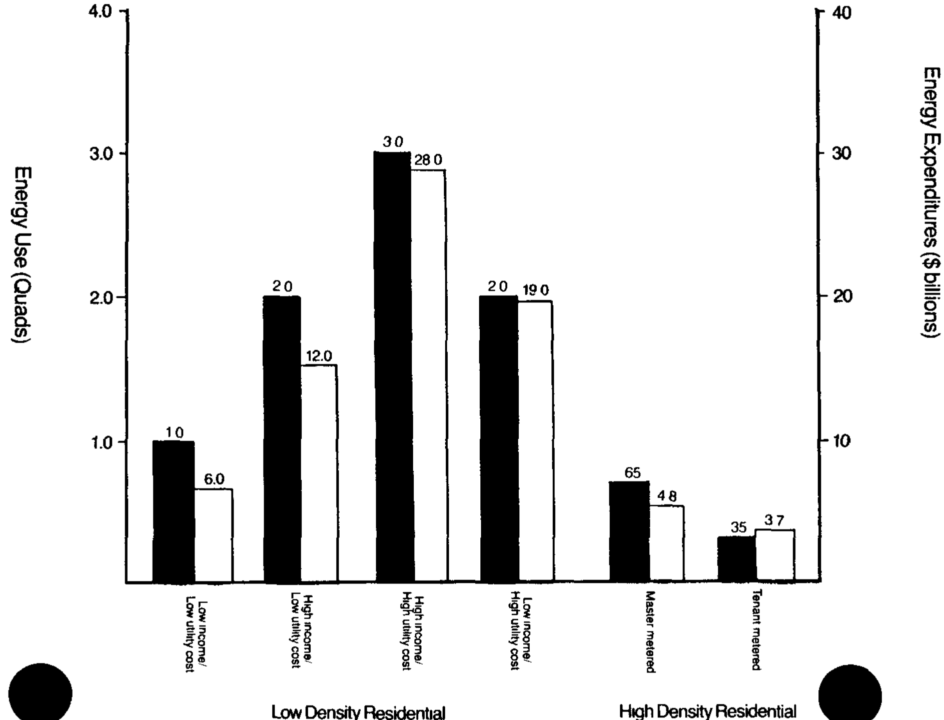


FIGURE 2

Existing Non-Residential Buildings—Energy Use and Cost

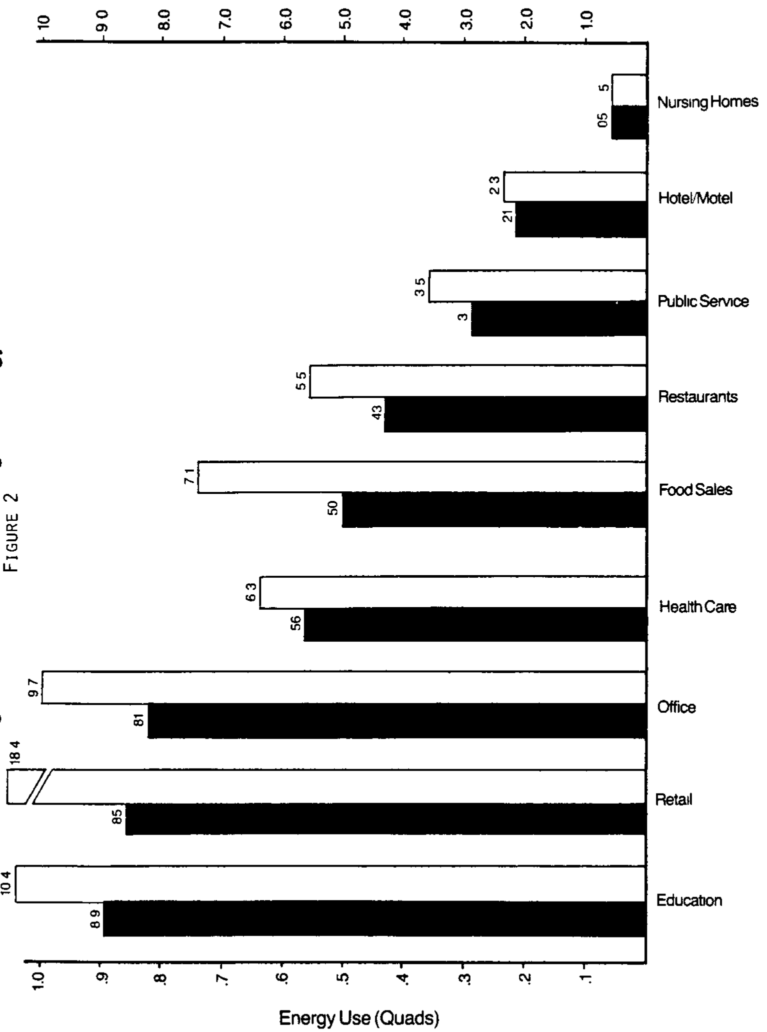


Table 1

Energy Consumption by End Use

Building Type	Energy End Uses (% of total energy consumption for building type) Heating	Cooling	Lighting	Domestic Hot Water
Low Density Residential				
Low Income/Low Utility Cost	65	4	7	24
Low Income/High Utility Cost	75	1	8	16
High Income/Low Utility Cost	55	20	6	19
High Income/High Utility Cost	65	14	4	17
High Density Residential				
Master Metered	56	12	10	22
Tenant Metered	54	8	10	28
Non-Residential				
Education	45	35	17	3
Retail	16	16	67	1
Office	41	35	23	1
Health Care	45	30	15	10
Food Sales	5	30	60	5
Restaurants	29	48	19	4
Public Service	40	35	23	2
Hotel/Motel	28	22	17	33
Nursing Homes	35	24	18	24

Table 2

Energy Cost by Building Type/Energy End Use

Building Type	Heating	Cooling	Lighting	Domestic Hot Water
	Energy Cost ($/MMBTU)			
Low Density Residential				
Low Income/Low Utility Cost	5.60	10.00	10.00	6.00
Low Income/High Utility Cost	7.90	16.00	16.00	9.30
High Income/Low Utility Cost	4.90	10.00	10.00	5.90
High Income/High Utility Cost	8.20	16.00	16.00	7.50
High Density Residential				
Master Metered	5.90	14.50	14.50	6.10
Tenant Metered	9.00	14.20	14.20	8.90
Non-Residential				
Education	8.30	14.90	14.90	7.30
Retail	8.20	14.90	14.90	8.00
Office	6.80	14.90	14.90	5.00
Health Care	8.30	14.90	14.90	8.20
Food Sales	9.20	14.90	14.90	8.00
Restaurant	8.30	14.90	14.90	9.30
Public Service	7.30	14.90	14.90	4.00
Hotel/Motel	7.90	14.90	14.90	8.70
Nursing Homes	7.20	14.90	14.90	4.50

Energy Use Factor
Energy Expenditure Factor

The Energy Use Factor combines (1) the difference between likely and potential energy savings, expressed as a percentage of total energy use; (2) the percentage of energy use attributable to a particular end use for a specific building type and (3) the total energy use, in BTU's, of the building type.

For example, in the case of the market segment education/heating, the Energy Use Factor of 2.8 is derived as follows:

$$\frac{A \times B \times C}{100} = \text{Energy Use Factor}$$

where

A = difference between potential and likely energy savings as a percentage of the total energy used for heating educational buildings = 7%

B = percentage of the total energy use of educational buildings devoted to heating = 45%

C = total energy use per year of educational buildings in BTUs = .89 quads

The purpose of the Energy Use Factor is to account for the significance of the gap between potential and likely energy savings in terms of the amount of energy that it represents. The Energy Expenditure Factor, which multiplies the Energy Use Factor by the applicable cost of energy, accounts for the energy costs associated with the differences between potential and likely energy savings. The two factors are useful in evaluating the segments of the retrofit market since the cost of energy varies considerably. Therefore, two market segments which may have identical Energy Use Factors, may have significantly different Energy Expenditure Factors.

The Energy Use and Energy Expenditure Factors are expressed in units of 10^{-2} quads and 10 million dollars, respectively. In other words, a Energy Use Factor of 14 is approximately .14 quads and an Energy Expenditure Factor of 47 represents $470 million in reduced energy costs. Since the Energy Expenditure Factor reflects annual savings in energy costs, it can be used to provide a general measure of the magnitude of the retrofit market. For example, if you assume that the applicable investment criteria is a three year simple payback, then the Energy Expenditure Factor should be multiplied by three. In the foregoing example, the resulting product of $1.4 billion provides an estimate of the investment in retrofit services and measures that can be economically justified for a specific market segment, but which will not be realized under current conditions. While the results of the analysis can be used to estimate the dollar magnitude of the retrofit market, it is noted that the primary purpose of the analysis was to provide a means of selecting market segments for program development, not to provide a definitive estimate of the retrofit market. Therefore, any projections derived from the analysis should be viewed as only approximations of the market for retrofit measures and services.

Figures 3 through 10 graphically indicate the Energy Use and Energy Expenditure Factors for each of the 60 market segments. Based on these factors, the following segments of the existing building stock stand out as prime targets for the development of conservation programs.

Low Density Residential

- -- High Income Households/High Utility Costs--All End Uses
- -- High Income Households/Low Utility Costs--Heating, Cooling and DHW
- -- Low Income Households/High Utility Costs--Heating, Lighting and DHW
- -- Low Income Households/Low Utility Costs-Heating and DHW

High Density Residential

- -- Master Metered-Heating

Non-Residential

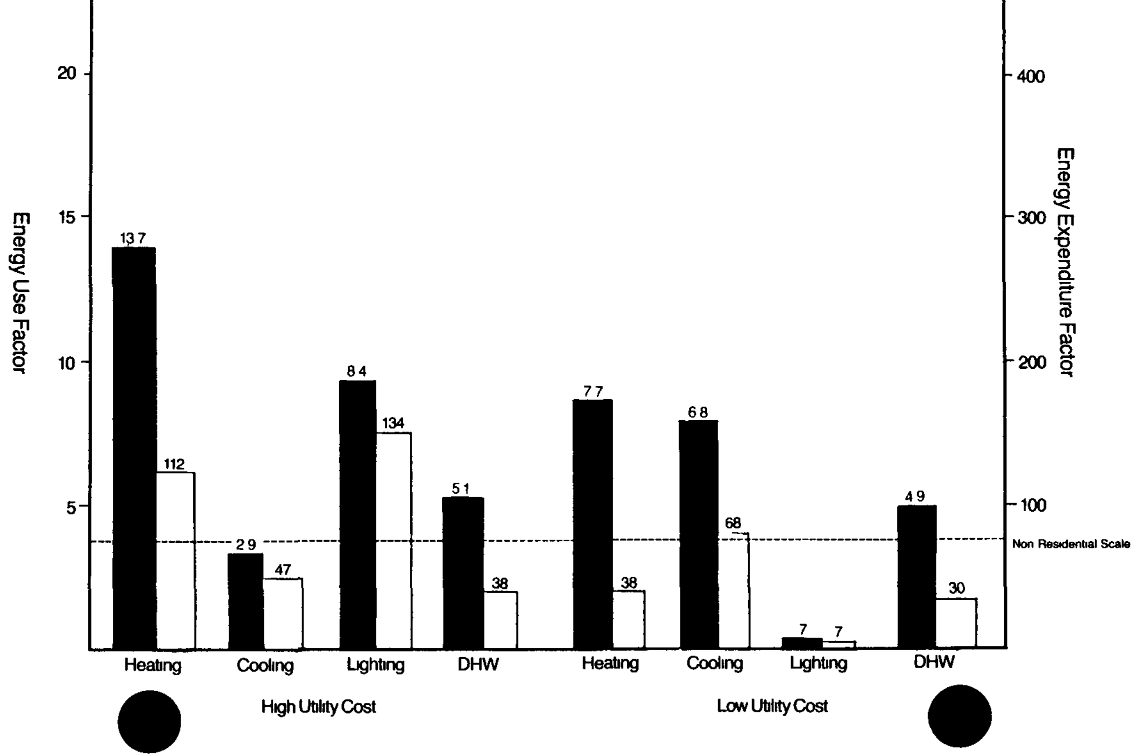
- -- Educational/Heating and Cooling
- -- Office/Heating, Cooling and Lighting
- -- Retail/Lighting
- -- Food Sales/Lighting

In addition to the foregoing market segments, it may be desirable to combine several segments for further study on the basis of one or more common features, eg. applicable conservation measures, decisionmakers, or barriers.

The project's sponsors are currently selecting the market segments that will be the subject of the next phase of the work. For each selected segment an individual plan of action will be developed and implemented by a committee composed of building community experts. Detailed analyses involving building owners, manufacturers, designers, and others will be conducted. Applicable technologies, the decisionmaking process associated with investments in energy efficiency improvements, and the barriers to increased energy conservation will be investigated in detail. The results of this effort will be a number of specific programs which will increase the near term market for energy efficiency improvements in the selected market segments.

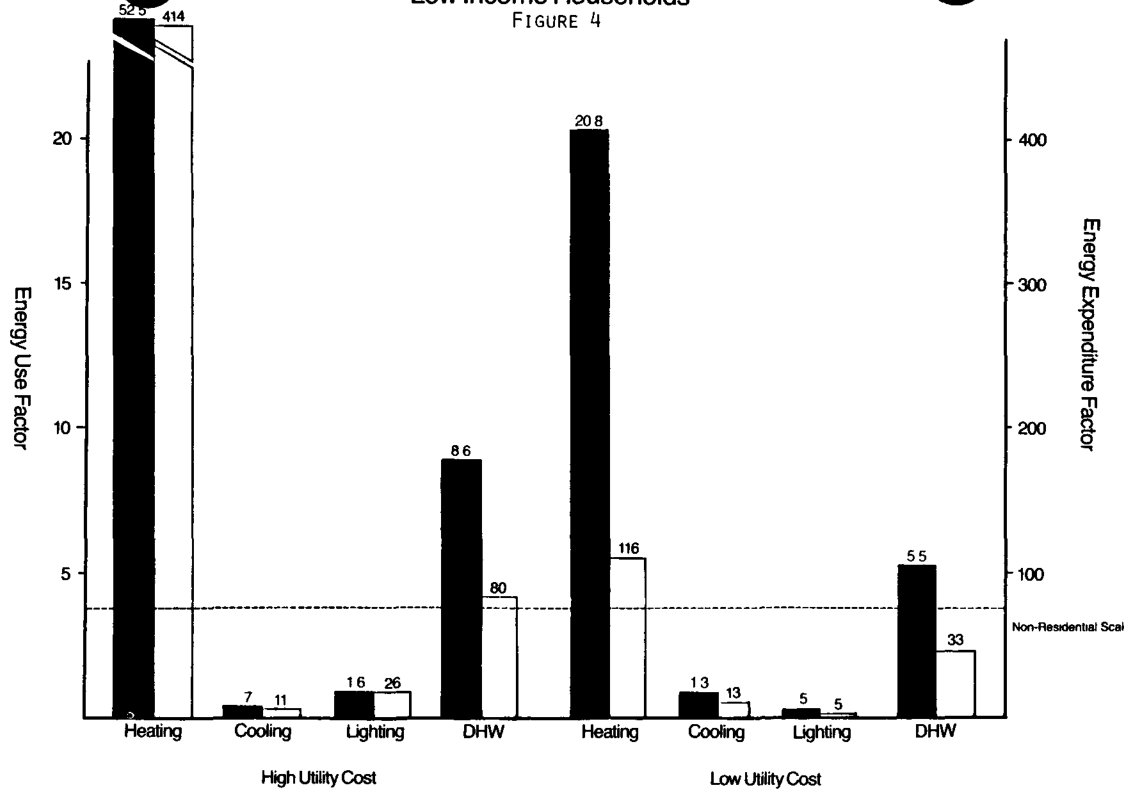
Segment Evaluation: Low Density Residential Buildings
High Income Households

FIGURE 3



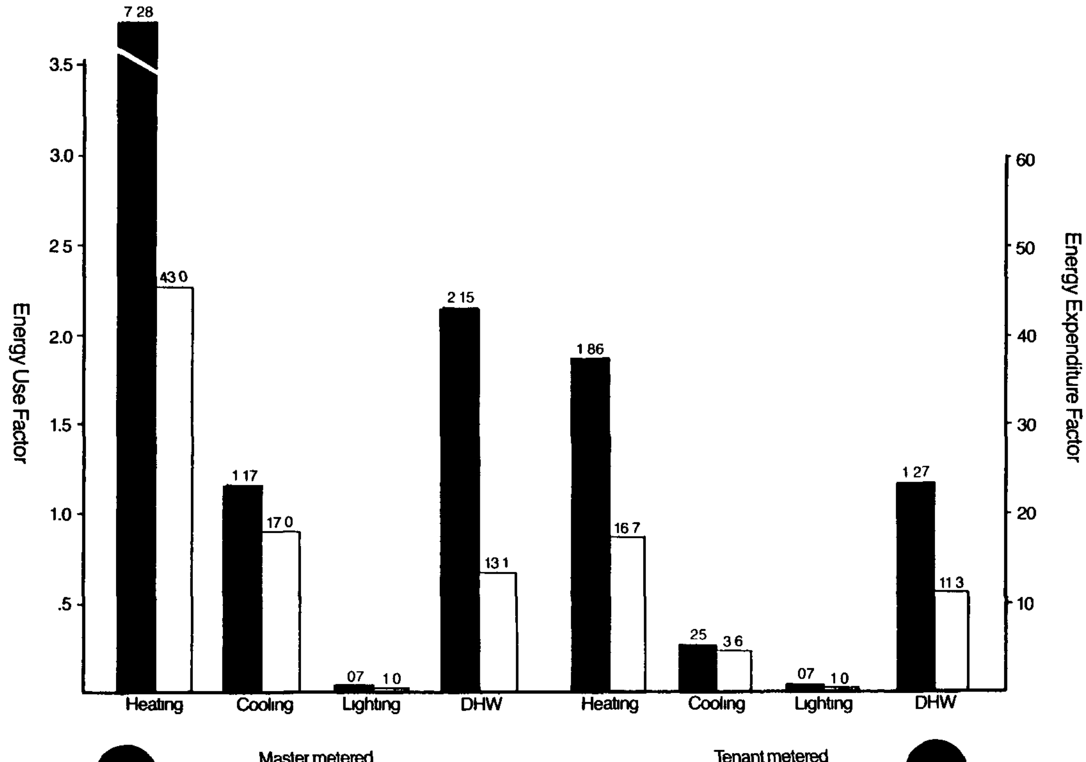
Segment Evaluation: Low Density Residential Buildings
Low Income Households

FIGURE 4



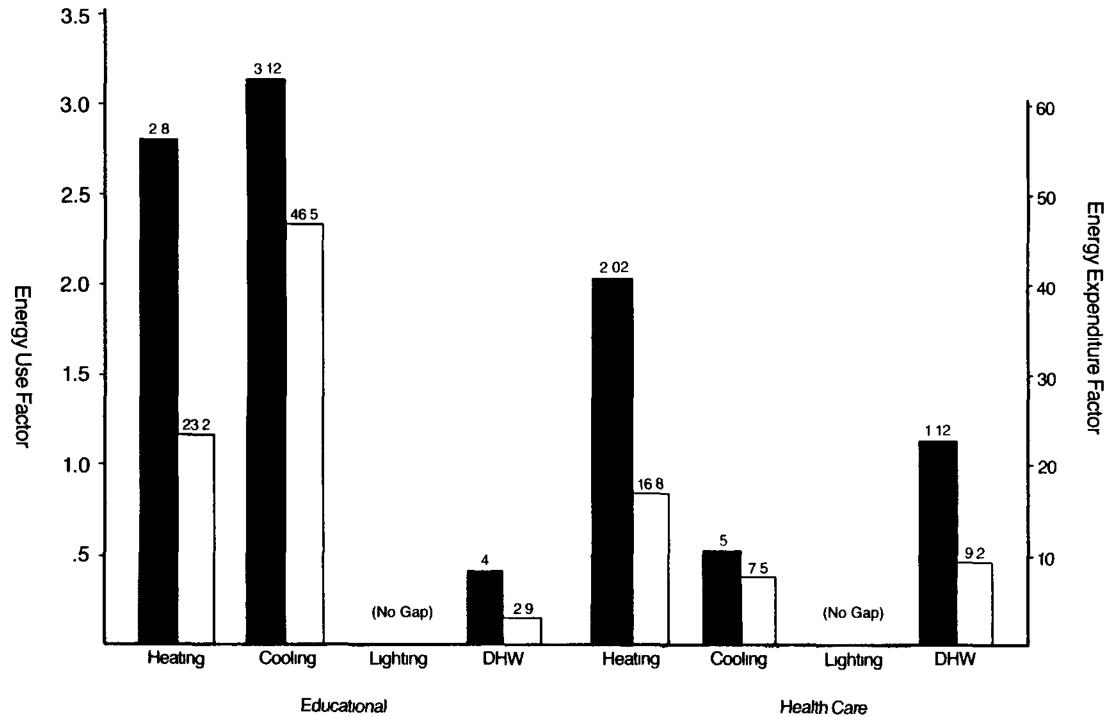
Segment Evaluation: High Density Residential Buildings

FIGURE 5



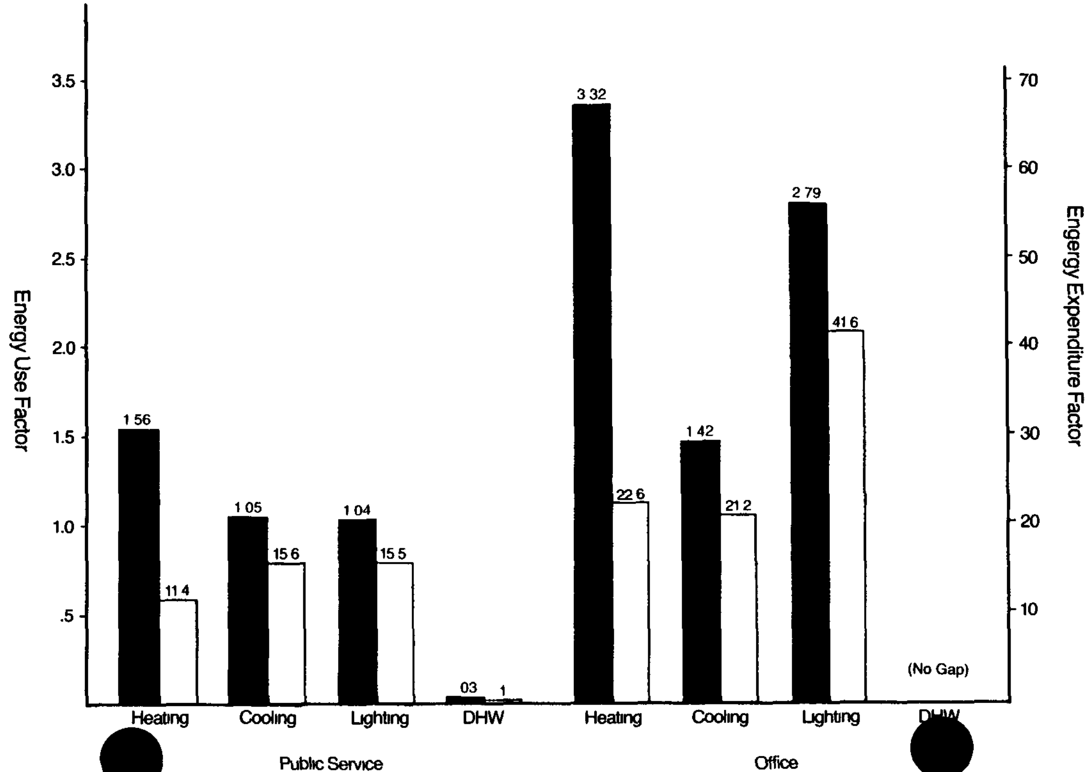
Segment Evaluation: Non-Residential Buildings

Figure 6



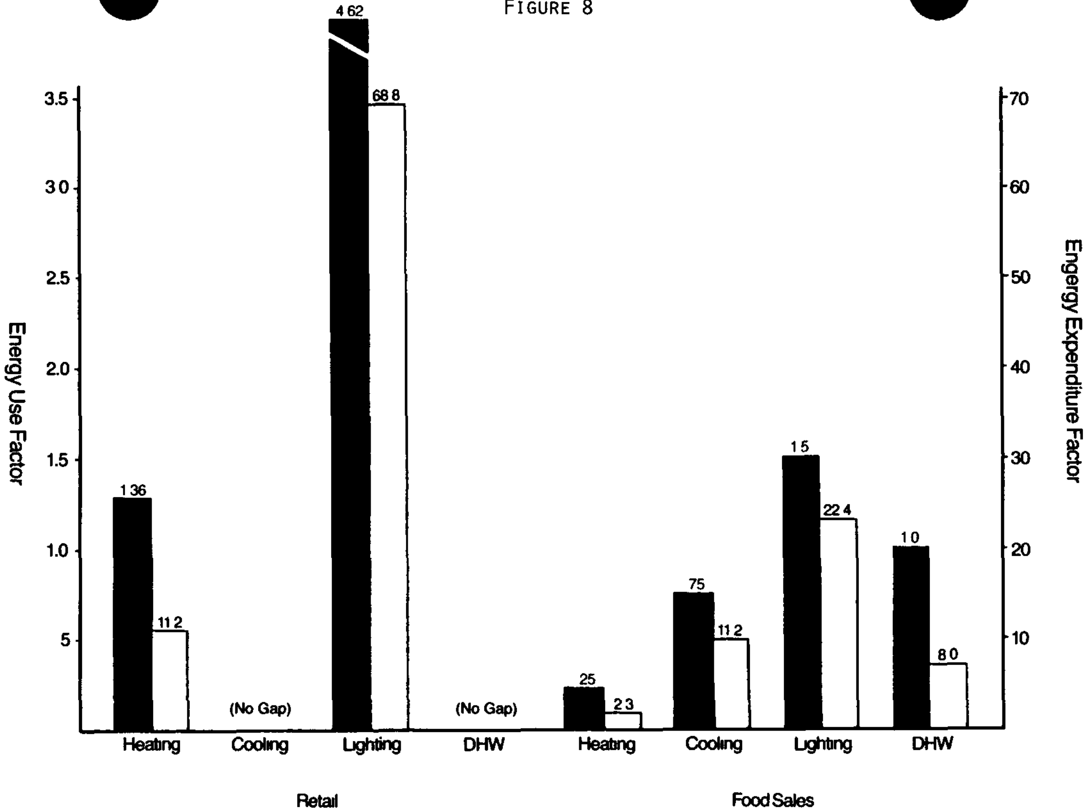
Segment Evaluation: Non-Residential Buildings (cont.)

FIGURE 7



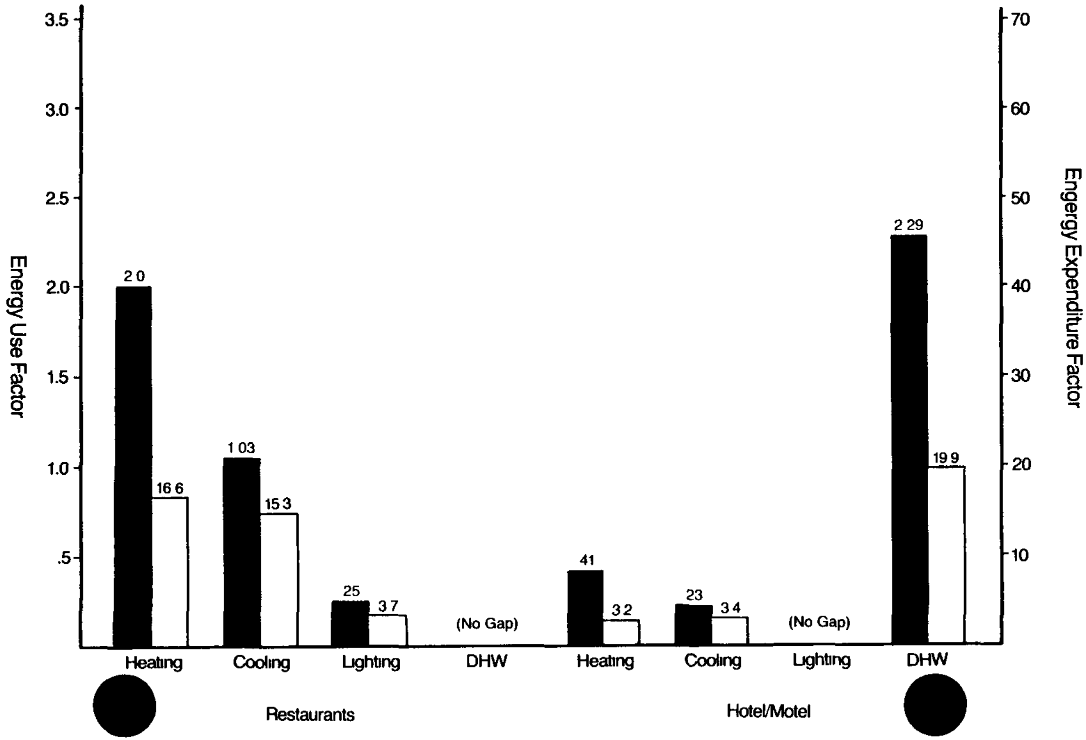
Segment Evaluation: Non-Residential Buildings (cont.)

FIGURE 8



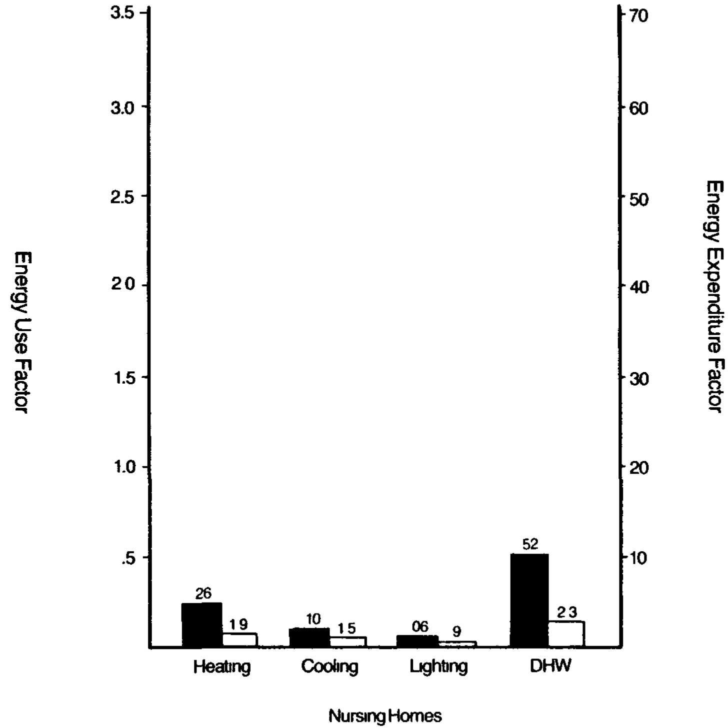
Segment Evaluation: Non-Residential Buildings (cont.)

FIGURE 9



Segment Evaluation: Non-Residential Buildings (cont.)

FIGURE 10



COMMERCIAL/INDUSTRIAL ENERGY AUDIT PROGRAM

William M. Leahy
Program Administrator
Northeast Utilities Service Company

Northeast Utilities Service Company (NU), providing electricity and gas to most of Connecticut and portions of Western Massachusetts, has proceeded with the development of a class A energy audit for its Commercial and Industrial customers despite the lack of a federal mandate. NU began offering this service to its 90,000 Commercial and Industrial customers in early 1982 and as of January 1, 1983 had completed over 1,550 audits. NU expects to conduct over 4,000 audits in 1983.

It now appears that the federally-mandated Commercial and Apartment Conservation Services (CACS) will become effective in 1983 once final proposed regulations are issued. NU's C/I audit more than meets the requirements of the CACS program. It offers both a more inclusive analysis and is available to many more customers than the CACS audit regulations require.

NU's Commercial/Industrial (C/I) audit program is part of NU 80s/90s, a comprehensive and cohesive conservation program developed in response to an order from the Connecticut Department of Public Utility Control (DPUC) in 1981.

NU identified the significant potential for conservation within its Commercial and Industrial sectors, a group relatively neglected in terms of receiving energy conservation information and assistance. The 1981 DPUC decision suggested that the charge for such a service be maintained at a nominal level. To this end, a stepped pricing schedule was developed in an attempt to make the charge appropriate to the size of the task.

The pricing schedule is:

Square Footage of C/I Facility	Cost per Audit
Up to 10,000	$ 25
10,001 - 25,000	100
25,001 - 50,000	200
50,001 - 100,000	300
Over 100,001	400

This pricing formula has the advantage of making it easy for potential users of the audit to calculate the price and it properly is based on the size of the building, not the customer's electric use.

AUDIT PROCESS

The C/I audit process is as follows:

- The business or apartment owner completes an audit application, answering questions about the business.

- For customers with over 10,000 square feet the computer produces a preliminary energy end-use analysis and a list of applicable measures from their audit applications based on the type of facility, size of facility, fuels used, and other pertinent information. This information is examined by the auditor prior to the site visit. This analysis is not considered necessary prior to site visits to the smaller buildings. The computer-processed preliminary audit analysis guides the audit inspection, improves the credibility of the auditor with the customer in terms of knowledge about the business, and improves the efficiency of the site visit.

- The auditor visits the facility, describes the results of the preliminary analysis, interviews the building supervisor and collects data for the report.

- The audit report is prepared by computer. The audit report includes:
  - -- An executive summary of the measures recommended, showing estimated costs and savings.
  - -- A facility and energy profile, describing the use of fuel in the facility, the energy use by end-use, and the fuel price assumptions used.
  - -- A write-up on each recommended measure, describing the equipment or operating change required, the likely cost, energy savings, and implementation instructions.

- The final audit report, although the text is computer produced, uses sector-specific language and appears customized. The computer printing is clear and readable. In addition, conditions noted at the site by the auditor can be word-processed into the final report. The computer system used for the report produces data sensitive to unique technical and economic considerations for the following sectors:
  - -- Apartment Buildings
  - -- Retail (excluding food)
  - -- Food Stores
  - -- Small Service
  - -- Offices
  - -- Hotel or Motel
  - -- Bakery
  - -- Wholesale and Distribution
  - -- Restaurants
  - -- Laundries
  - -- Auto Dealers and Service Stations
  - -- Industrial Sectors

- All information is prepared in a manner consistent with business decision-making and accounting practices.

- The savings are computed in the most accurate way possible by assuming implementation of short payback items first, adjusting the end-use profile, and computing savings from longer payback items.

This computer program was developed by Xenergy, an engineering firm located in Burlington, Massachusetts specializing in solutions to energy problems.

The computer program applies to both the small facilities under 10,000 square feet and the medium-sized facilities over 10,000 square feet but under 1,000 kW. The system uses a unified approach. There is, however, a difference in the length of time taken for an audit: as more measures apply to larger facilities and auditor site time is longer.

DATA RETRIEVAL FOR ANALYSIS AND EVALUATION

All data associated with the program concerning facilities surveyed, audit results, and computer costs and savings are readily available in computer produced, tabular form. These data are used by NU on an aggregated basis to evaluate the effectiveness of the audit program in actually producing energy savings. The data is also used to greatly improve NU's understanding of the characteristics of the commercial and industrial classes and will thus enhance its forecasts of energy use.

FINANCIAL ANALYSES

The financial analyses for the measures which cost over $200 provide the following data for each of the ten years following implementation and in total for the period.

- Pretax dollar savings
- Energy conservation investment
- Pretax cash flow
- Annual depreciation on the energy conservation investment
- Taxable income after depreciation
- Annual tax impact
- After tax cash flow

In addition, a computation is made of internal rate of return before and after taxes, payback, and net present value of the investment. These are the most popular financial decision variables in general business use today.

Because implementation costs are low, detailed financial analyses are omitted for operation and maintenance (O&M) measures.

PRE-ENGINEERING ANALYSIS

For the small businessperson the audit report in most cases will suffice as a guide to practices to adopt and investments to make. As the list of topics of measures above indicates, however, the audit cannot serve as a substitute for engineering on some of the larger investment items. It will, in those cases, tell the customer what to ask for, and, through its financial analysis, indicate whether the customer would find it worthwhile to have an engineering firm prepare detailed specifications.

TIME REQUIREMENTS

The estimated average auditor time per audit for customers in buildings of 10,000 square feet or less is 6 hours, including travel, site inspection, pre- and post-visit preparation, and a second visit to present the results. The average estimated time per audit for the larger customer is 10 hours.

Beginning in 1981, training of 110 Energy Management Services (EMS) field energy consultants began. This training included media presentations, simulations and site visits. Each field consultant is expected on average to perform four to five audits per month as part of his normal responsibilities. The field organization includes one lead auditor in each district.

MUNICIPAL BUILDINGS

EMS field consultants recommend NU's C/I audits to municipalities for their buildings. In 1982, 82 audits were performed for municipalities. The information on the audit report is particularly useful in that it can be used to justify expenditures that should pay for themselves in a relatively short time, and thus provide an effective basis for a budget request. These audits required an average of 8.5 hours of field time as compared to an average of 15 hours to complete a federal SHLP audit.

MULTIFAMILY DWELLING AUDIT

NU's C/I audit is designed to treat multifamily buildings 5 units and larger. In mid-1982, the audit was fully developed for use in multifamily buildings. Over 100 audits were performed on multifamily buildings in 1982. Many of these were buildings involved in the HUD

Flexible Subsidy Grant program and the results are being used to plan the measures that will reduce energy costs in those buildings whose residents are receiving federal rent subsidies.

The NU C/I audit will be used to audit the whole building envelope in connection with the RCS apartment audits to be introduced in 1983 for Connecticut and Massachusetts. This continuation of audits will be particularly useful when the building owner and tenants are involved. The C/I audit can cover the heating system and the building shell, all areas where investment from the owner are needed. The RCS apartment auditor will counsel the tenants and do the apartment-by-apartment surveys which the C/I audit is not equipped to handle.

1982 RESULTS AND 1983 GOALS

During 1982, 1,550 audits were performed. Audit leads were generated through direct mail and direct customer contact.

Promotion in 1983 will be more extensive than in 1982 and will include:

- Introduction of new, more identifiable name
- Direct mail
- Quarterly bill inserts
- Advertising in trade magazines and newspapers
- Display materials
- New brochure
- Promotion through customer contacts using the personal sales approach
- Speeches - slide show and handouts
- Workshops and seminars

The 1983 programs goals are:

Size of Building	Total Number of Audits
10,000 sq. ft. or below	3,240
Over 10,000 sq. ft.	660
Municipal buildings	100
	4,000

ENERGY SAVINGS

The audits completed have resulted in a data base which can be examined from a number of points of view. Included in this report are a number of findings useful for evaluating the potential for conservation among the audited customers:

- Average potential energy savings versus energy us On Exhibit 1 is a presentation of the average ene that the C/I audit has pointed out can be saved by facility type for recommendations with a payback of less than four years (with an average of 1.87 years payback for investment on all measures. Exhibit 1 also shows that for all facility types the share of energy that could be saved if the audit recommendations were put into effect is greatest for oil (an average of 36.8 percent savings potential across all facility types), somewhat less for gas (23.83 percent potential savings) and least for electricity (11.85 percent savings). The potential for savings on the direct use of fossil fuels is greater in each of the facility categories than is the potential savings from electricity use reduction. The greatest share of savings is to be found in Small Service, Hotels and Motels, Office Buildings and Bakeries, the least in Laundries and Food Stores. What is most remarkable about the presentation of Exhibit 1 is the evidence of a large amount of cost-effective potential energy savings in the commercial class, even after many years of escalating fossil fuel prices and publicity regarding the potential for energy conservation.

- Payback: This data was compiled from measures recommended in 917 audits conducted since July 1, 1982. The audit used by NU in this program contains 67 separate conservation measures. The most frequently recommended measure is the installation of energy-efficient fluorescent lamps with a mean payback of 1.77 years. Other measures recommended in a substantial number of audits were adding weatherstripping and caulking (payback 2.81 years), reducing lighting levels (payback 0.14 years), install automatic temperature setback (payback 0.85 yea installing roof/ceiling insulation (payback 3 years), lowering heating temperature (payback 0.31 years), installing storm windows (payback 4.84 years). Most of the measures recommended have a payback of less than two years, and only the window

EXHIBIT 1

NORTHEAST UTILITIES CONSERVATION PROGRAM FOR THE 1980s AND 1990s

AVERAGE ENERGY USED VERSUS AVERAGE ENERGY TO BE SAVED BY FACILITY TYPE
IF NU ENERGY CHECK AUDIT RECOMMENDATIONS WERE IMPLEMENTED

917 AUDITS

		AVERAGE ENERGY								
		kWh			Gas (Therms)			Oil (Gallons)		
Facility Type	Number	Used	Potential Savings	%	Used	Potential Savings	%	Used	Potential Savings	%
Office Bldg.	299	98,286	14,945	15.2	2,317	896	38.7	3,160	1,554	49.2
Retail (Nonfood)	110	46,490	8,450	18.2	1,888	197	10.4	1,112	389	35.0
Food Store	15	208,449	26,688	12.8	1,657	92	5.5	220	17	7.7
Small Service	35	28,774	3,548	12.3	1,551	145	9.3	2,135	1,246	58.4
Auto Dealer/ Service Sta.	55	61,261	9,738	15.9	3,574	1,304	36.5	2,691	1.047	38.9
Restaurant	26	143,878	11,024	7.6	3,705	405	12.1	1,537	658	42.8
Hotel/Motel	21	166,346	37,995	22.8	11,308	4,962	43.8	4,353	2,212	50.8
Bakery	7	52,502	3,325	6.3	3,363	606	18.0	169	82	48.5
Laundry	7	73,356	3,015	4.1	8,919	547	6.1	11,605	179	15.5
Warehouse	20	110,616	7,689	69	4,717	2,076	44.0	3,009	1,050	34.8
Small Ind. Shop	50	389,943	37,047	8.5	12,595	2,881	22.9	7,058	2,495	35.4
All Multifamily	47	63,444	6,746	10.6	22,479	8,676	38.6	2,616	646	24.7
Average Percent Potential Savings				11.85			23.83			36.8

treatment measures (storm windows and additional glazing) are shown to have average paybacks of four or more years. The ratio of total potential expenditures to total potential dollar savings is 1.85, thus showing that the average payback is less than two years. For most businesses, this is an acceptable return, although available investment funds have many competing uses, and thus energy conservation may not be selected.

CONCLUSION

All indications are that there is a significant amount of energy to be saved through conservation in the Commercial and Industrial sectors. It is also apparent that this group is in need of low-cost accurate information on conservation opportunities presented in a format useful to the business community.

Public utilities are in a good position to deliver this type of service. It has always been a goal of public utilities to instruct their customers in the proper utilization of energy. This service will breed healthier customer; and healthy customers make good customers.

"RETREAT FROM REHEAT"

A CASE HISTORY IN ENERGY CONSERVATION

Richard C. Lozon
Michigan Consolidated Gas Company

ACKNOWLEDGEMENTS

The information, ideas, operating concepts, and attendant results presented in this paper were produced through the efforts of a Facilities Management Team, comprised of Building Superintendent, David Snyder, Facilities Engineer, Patrick Ryan, and the author, along with Shift Supervisors and Equipment Operators.

The author also wishes to acknowledge that this paper represents one case history of many across the United States, perhaps some of greater merit, which could have been presented.

INTRODUCTION

In January of 1963, the One Woodward Building became the gem of the Detroit skyline. Unique in its architecture, Minoru Yamasaki produced a design and appea-[illegible]nce, which still today projects a class and distinction [illegible]d by few other Detroit buildings.

More importantly, the mechanical, electrical, and other systems within the structure were designed with features that allow them to be operated surprisingly up-to-date in respect of current day energy management concerns and problems. This paper deals specifically with the mechanical system, which has provided the basis for the energy management results described later.

DESIGN BACKGROUND

Original design criteria for One Woodward were 75°F. and 50% relative humidity indoor, with outdoor temperatures ranging from -10°F. to 95°F., which were standard conditions for design in Detroit in the 1960's.

Original design, total maximum building heat load is approximately as follows:

Heating and ventilating	20,800 BTU's per hour
Snow melt system	5,500 BTU's " "
Domestic hot water	2,000 BTU's " "
Winter A/C load	500 BTU's " "
Boiler feedwater heater	2,000 BTU's " "
Total	30,800 BTU's per hour

Original design, total air conditioning load per floor is approximately as follows:

Total Tonnage Per Floor		58.5 Tons
External heat gain	25%	(including solar)
Lights	42%	
People	6%	
Make up air	20%	
Internal mechanical and electrical	7%	
Total	100%	

Original design, total building air conditioning load is 1,520 tons.

The prime mechanical components of One Woodward are located on the top three floors of the building. There are two 760 ton absorption chillers on the 28th floor, plus two smaller 150 ton intermediate chillers. The absorption units are propelled by two 20,000 lb. per hour boilers located on the 29th floor. Building heat is rejected to the atmosphere through two cooling towers located on the 30th floor roof.

The steam and chilled water are delivered throughout the building by two vertical headers. Each floor is then served through a mechanical room local to each floor.

Heat is delivered to the floors by perimeter sill units which form the terminal end of the reheat system. Each sill unit has a heating coil which receives hot water circulated from the local mechanical room, and an air supply from the central fan unit within the mechanical room. The call for heat comes from a pneumatic wall mounted thermostat which controls a by-pass damper in the sill unit to allow more or less warm air. Interior zones have cool air only supplied through overhead lighting coffers in amounts sufficient to compensate for the heat of the lights. Controls for all local mechanical room equipment such as fans, perimeter water pumps, outdoor air dampers, and other features of the local mechanical rooms are terminated in a central control room on the 29th floor adjacent to the boiler room, along with supply and return air temperature readings for each floor.

The 29th floor control room has control features which allow the local fans to be turned from off to slow to fast. Outdoor air dampers can be placed closed, minimum, or at automatic settings. Perimeter hot water can be reset with a master controller from 90°F. to 260°F. Perimeter hot water pumps can be turned off and on from the control center.

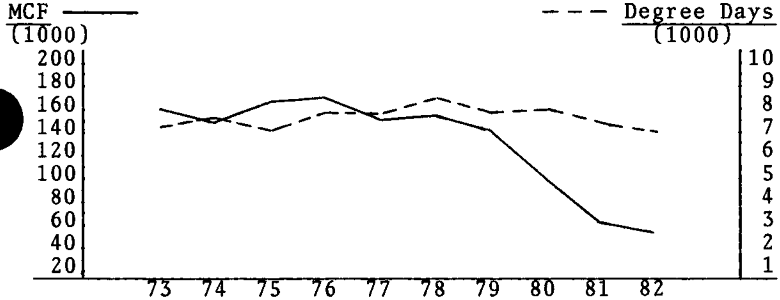
In addition to the HVAC controls, the 29th floor control center also handles fire, life safety, elevators, and other calls and signals from throughout the building.

OPERATING HISTORY

From 1963 until 1979, the HVAC system was operated as designed, or essentially in the automatic mode. Boilers and chillers were run at full potential, with little or no load reset, and the wall thermostats balanced the thermal force between the two systems.

Outdoor air dampers were kept in the automatic mode and perimeter hot water temperatures were in the 240°F. to 260°F. range.

ENERGY STATISTICS



CURRENT OPERATING STANDARDS

THEORY OF OPERATIONS

During 1979, a study of the environmental system revealed that with the present equipment, the building could be operated much more efficiently, and with relatively few tenant complaints, by using a revamped operations model.

The building was viewed as having to undergo six basic atmospheric conditions.

1. Summer conditions with solar load.
2. Summer conditions without solar load.
3. Winter conditions with solar load.
4. Winter conditions without solar load.
5. Spring and fall conditions with solar load.
6. Spring and fall conditions without solar load.

Summer conditions generally begin around May 15 and last through September 30. Winter conditions generally begin around November 1 and last through March 15. Spring and fall conditions generally occur between March 15 and May 15 and between September 30 and November 1.

Each season was broken into temperature ranges as follows:

Winter	Temperature Range	-10°F. to 20°F.
Winter		20°F. to 35°F.
Spring and fall		35°F. to 50°F.
Spring and fall		50°F. to 65°F.
Summer		65°F. to 75°F.
Summer		75°F. to 95°F.

For winter temperature ranges from -10°F. to 20°F., boilers are operated at approximately 18 psi with outdoor air used for both cooling of floors with internal heat load and to produce chilled water to send to floors where outdoor air is not accessible to internal heat load.

For summer temperature ranges between 55°F. and 95°F., there is no perimeter heat supplied to the building. Steam pressure to the chiller is varied proportionately to outdoor temperature between 60°F. and 95°F. to produce chilled water in sufficient amount and temperature to meet demand. Outdoor air is held at a minimum with selective floors being more ventilated at night.

During spring and fall, each day is handled separately depending on weather trends. If the temperature is 60° or below and steady, the boilers are banked and outdoor air is used for all cooling, including making chilled water by the counterflow method.

The main ingredient of current operations is operator awareness. At the start of each shift, each operator must call the local U.S. weather station for an updated forecast. Building loads are then anticipated approximately four hours in advance.

If conditions are changing slowly, little or no modification is made to the current operating standards as shown in the computer model graph. Conversely, if conditions are expected to change rapidly, then corresponding adjustments are made in accordance with the current operating standards.

This procedure levels the energy peaks and takes advantage of valleys which ultimately produces energy savings by avoiding overheat and/or under cooling.

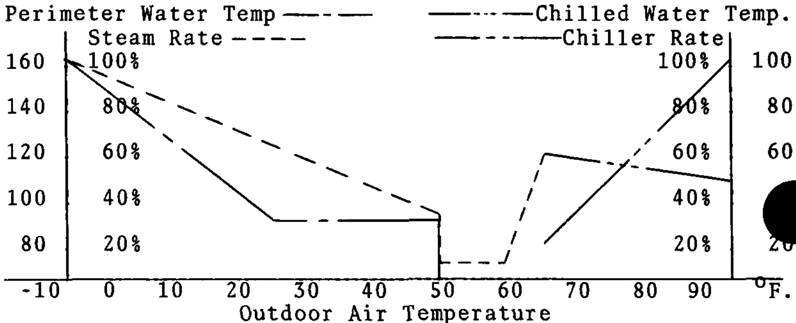
During summer conditions the chillers are started at 6:00 a.m. on automatic and the boiler pressure is varied to meet demand. The operator is responsible to monitor chiller output, return air temperatures for each floor, and adjust steam pressure in respect of load changes.

During daily operations, the boiler pressure is varied with weather conditions and the hourly monitoring of floor temperatures.

COMPUTER MODEL

Using the above set of operating standards, a computer model of the building was developed for loading into a simple software package by which the building can now be automatically controlled with the installation of an Apple or similar type of micro/mini computer device, and appropriate hardwiring.

The computer model details the operating mode for the full range of outdoor temperature between -10°F. and 95°F. including settings for boiler, chiller, and all local mechanical room equipment.



Closed 45 min./hour	Minimum 7am-6pm	Automatic 7am-6pm	Closed or Min based on R.H.

Damper position

SYSTEM CHANGES

All of the energy related or consuming systems have been changed in some way from original design.

BOILERS

The preventative maintenance program and the State of Michigan boiler inspection and maintenance laws have caused the boilers to be kept in excellent condition over the years. However, new combustion controls were added in 1979 to improve combustion efficiency. A flue gas analyzer automatically provides input to a combustion controller so as to maintain approximately 2% oxygen residual at normal firing rates. A new plant master controller allows the operator to adjust system pressures in response to changing building demands or loads. The project cost for the combustion control system was approximately $35,000. Payback is estimated at one year. The boilers are now operated with variable pressure, depending on load and time of year, on a day to day basis.

CHILLERS

The chillers were retubed after 20 years of operation which contributes some positive measure of energy efficiency. This cost is not considered part of the energy management effort.

In addition to chiller retubing, new hermetic pumps were installed replacing older open seal pumps, and a new control system was added to automatically cycle the chillers in response to load changes, with manual override. Site glasses were eliminated where possible. The total cost of this project was approximately $31,000, with pay-back estimated at one year.

HVAC SYSTEM

Perimeter water system temperatures are adjusted downward through an outdoor system reset controller, so as to operate between 160°F. maximum and 90°F. minimum, as outdoor air temperatures range from -10°F. to 25°F. Perimeter water temperatures are varied from the main control center in accordance with a master reset schedule.

AIR FILTRATION SYSTEM

The original design of the local floor air filtration system consisted of high efficiency cartridge filters with media pre-filters. This entire system has been replaced by single component (24" x 24" x 4") air filters of the modern variety of impingement type, and these filters are replaced annually. This change has increased heat transfer rates and reduced fan horsepower required for air handling.

MONDAY MORNING WARM-UP CYCLE

The originally designed local floor mechanical system included a reheat coil, which was for the purpose of system reheat. The control system for the reheat coil has been modified to allow for higher temperatures within the coil for Monday morning warm up which has allowed us to let building temperatures depreciate over nights and weekends to a lower level so that by using the reheat coil for warm up, we can bring the building up to temperature at the beginning of the operating day in approximately 45 minutes.

OUTDOOR AIR DAMPER SYSTEM

The outdoor air and exhaust damper operation has been changed so that below 35°F. the system operates on minimum air intake. Between 35°F. and 75°F. the dampers operate in the automatic mode. Above 75°F. the system goes back to minimum air intake. Each operating day requires minor adjustments to the general operating plan as a function of building temperatures.

CHILLED WATER PRODUCTION BY OUTDOOR AIR

When the outdoor air temperature is below 50°F., the chillers are banked and floors using outdoor air for cooling of internal heat loads are allowed to run with somewhat greater than needed outdoor air quantities. This outdoor air is passed over the cooling coil through which chilled water is still being circulated by operating the main chilled water pumps, and by-passing the chillers. With the boilers and chillers banked, and chilled water flowing through the main header system and thus through the cooling coils on floors that use significant quantities of outdoor air for internal cooling, the chilled water is reduced in temperature by the incoming outdoor air which is increased in temperature so as to allow approximately 10 tons of chilled water production, per generating coil, through the use of outdoor air.

SIDEWALK SNOW MELT SYSTEM

The building sidewalk snow melt system normally w allowed to operate from fall until spring at fairly significant temperatures. This operation has been modified to allow the system to idle, with the operator being responsible to anticipate weather conditions that require larger heat input for snow melting. This contributes to a significant reduction in steam load and lost heat.

RESULTS

As the reader can see from the Energy Statistics graph, energy consumption for heating, ventilating and air conditioning in the One Woodward Avenue building has declined from an average rate of 145,000 MCF annually to approximately 60,000 MCF annually. In terms of energy budgets for buildings of this type, this equates to a reduction from approximately 350,000 BTU's per sq. ft. to approximately 130,000 BTU's per sq. ft. for HVAC.

CONCLUSIONS

Unquestionably, the main conclusion that our Facilities Management team has drawn from the experience gained in the last several years, is that each building has its own characteristics which can be arrived at only through empirical methods. Scientific methods are useful in drawing general conclusions about directions which can be pursued for improvements in efficiency, however, the limits under which a building will operate must be tested more from the point of view of art than science.

ENERGY SAVINGS FOR COMPUTER FACILITIES

JOHN GRIFFIN, PRESIDENT
THERMOCYCLE INTERNATIONAL, INC.

The computer's transformation from an object of scientific awe to the business world's workhorse has bred some serious problems in the area of energy conservation. Expensive, fuel-consuming air conditioning systems must often operate 365 days a year to siphon off the tremendous heat generated by the computer system. It is not uncommon to see electrical usage of 20 to 30 watts per square foot in a typical computer room. This is 10 to 15 times the consumption of a normal office electrical load. The computer space is sealed off from other building areas and has no source of humidity other than personnel (minimal in today's computer facilities) and minor infiltration from the opening and closing of doors. Business machines, particularly those handling paper and cardstock, are problematic in extremely low as well as extremely high humidity conditions. Precise control of the temperature and the humidity is essential to the proper operation of this equipment.

The early design of these air-conditioning systems incorporated direct expansion Freon units connected to a central cooling tower. These systems are designed to operate with evaporator coil temperatures of 35° to 40° F. Dehumidification occurs during the cooling process due to the low coil temperature. Humidifiers simultaneously operate to bring the humidity up to the required operating conditions.

Engineers and manufacturers, recognizing this inefficiency of dehumidfying and humidfying with the same system, have utilized central chilled water systems which operate at coil temperatures of 48° to 55° F. A further modification produces major savings by utilizing the cooling tower to generate this 48° water during the fall, winter, and spring seasons.

Large data processing users, such as Manufacturers Hanover Trust, The Equitable Life Assurance Society of America, and the Home Insurance Company, have solved these problems by using the STRAINERCYCLE direct-injection "free cooling" system. STRAINERCYCLE, developed by Thermocycle International, Inc., conserves energy by making it possible to run air conditioning systems without using costly steam or electricity. A sophisticated automatic strainer, coupled with a specific water treatment program, allows the use of water from the cooling tower, instead of refrigeration machinery, to remove the excessive heat from the computer equipment.

The STRAINERCYCLE installation at Manufacturers Hanover Trust's headquarters at 4 New York Plaza in downtown Manhattan illustrates just how effective the process can be.

The bank's data processing centers occupy the equivalent of two and one-half full floors for a total of 90,000 of the building's 880,000 square feet and consume a major portion of the energy supplied to the building. Built in 1967, when energy was inexpensive by today's standards, 4 New York Plaza uses steam as its main energy source. The computer facilities have the typical raised floor and are serviced by special air conditioning units, with a chilled water coil connected to the central air conditioning system.

STRAINERCYCLE was installed in March, 1979, and two years later it had cut energy costs by $382,131 and paid for itself in less than 12 months.

The bank's Facilities Management Area estimates that STRAINERCYCLE saved $296,600 in 1981 alone, based on current New York City utility rates. Actual energy saved was 381,900 KW of electricity and 20,800,000 pounds of steam per year.

"Manufacturers Hanover usually looks for a two or three-year payback when implementing energy conservation measures," according to John Pechulis, Vice President, "STRAINERCYCLE's payback of less than 12 months has made it an indispensable part of our energy conservation program," which is considered very progressive among institutional corporations. The bank, which purchased the system after a rigorous analysis by Meyer, Strong & Jones, the engineering firm that originally designed the mechanical systems for 4 New York Plaza, now would recommend the system to other users with similar needs, and, "will implement it in other bank facilities where applicable."

At the Home Insurance Company headquarters at 59 Maiden Lane, in lower Manhattan, where the computer facility occupies several floors of the office tower's 932,000 square feet, STRAINERCYCLE has been in operation since February, 1977. In 1980 alone, the system saved 29,176,000 pounds of steam or $370,000 over the period of one year. At the latest New York City utility rates, of $16 per 1,000 pounds, potential savings have jumped to $446,816 per year.

A recent report of savings for the Equitable Life Assurance Society's facility at 1285 Avenue of the Americas, in midtown Manhattan, is even more impressive.

The Equitable Life Assurance Society has reported that although their STRAINERCYCLE installation has been in operation for less than two months and it has already paid for itself! The reason is that the Equitable Life Assurance facility at 1285 Avenue of the Americas has a supplemental 465-ton chiller for their computer rooms. Before STRAINERCYCLE was installed, the maintenance on this supplemental unit had to be done in the summer months when the computer rooms could be cooled by the main building chillers at a cost of approximately $200,000. Now the maintenance on the supplemental chiller can be done during the winter with STRAINERCYCLE providing "free cooling" to the computer rooms.

Exactly how does STRAINERCYCLE make these savings possible? The system automatically goes into effect whenever the air temperature drops below 50° wet bulb. At that level, water produced by the cooling tower is cool enough for the air conditioning system's chilled water circuits. STRAINERCYCLE then draws water from the cooling tower, filters it completely of extraneous debris, chemically treats it, and injects it directly into the chilled water circuits, thus eliminating the need to run refrigeration machinery. (See Exhibits A & B)

Each STRAINERCYCLE system is custom-engineered to achieve maximum savings.

NORMAL CYCLE

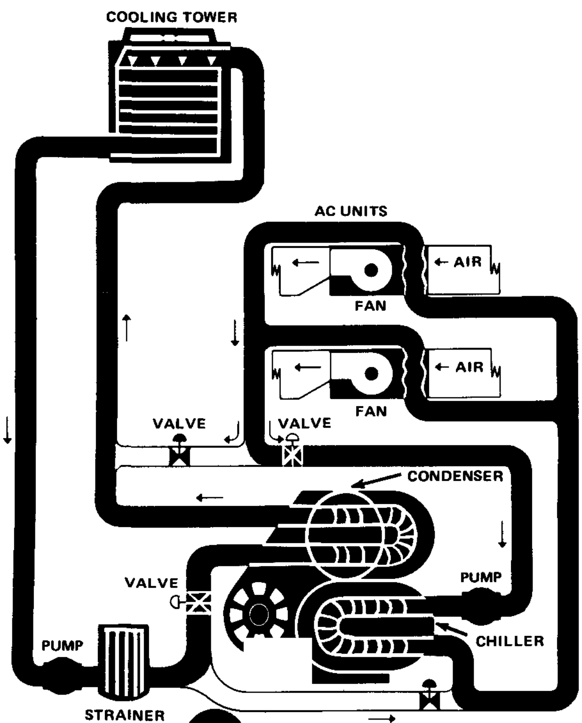


EXHIBIT A. Normal Cycle

STRAINERCYCLE®

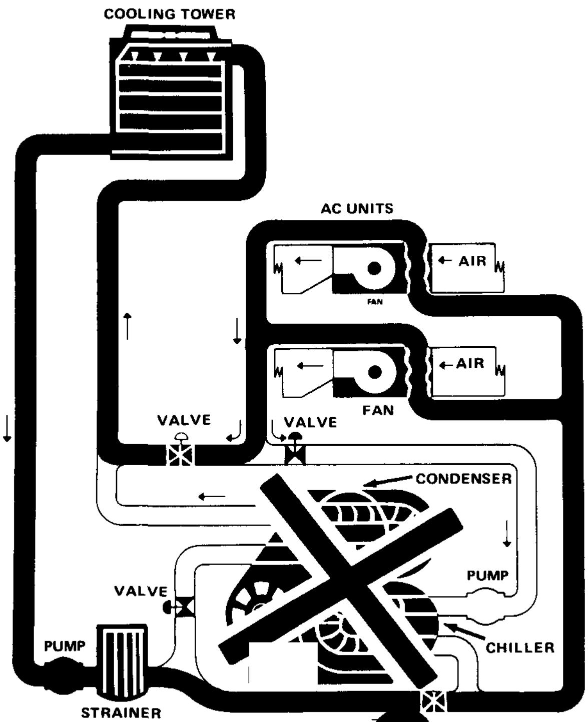


EXHIBIT B. Strainercycle

Because refrigeration machinery is essentially "off" when STRAINERCYCLE is "on", savings can be metered directly.

Another advantage of turning off refrigeration machinery is that it prolongs the life and reliability of that equipment. At 4 New York Plaza, where the compressors were taken off-line for approximately 6,700 hours over a two-year period, this equipment was given the equivalent of one year of rest. Moreover, by slashing running time by 50%, the bank saved approximately $16,000 in equipment repair.

During down-time for repairs and service, which occurs annually for any large computer facility such as the one at the Equitable Life facility, STRAINERCYCLE allows computer operations to flow smoothly without interruption precisely because it keeps the machines off-line. While STRAINERCYCLE provides "free cooling," one chiller can be serviced with the second unit on "stand-by" as a back-up, should that ever be needed.

Of chief concern to all operators of "free cooling" systems, is knowing when and when not to change over to "free cooling." An accurate means of monitoring outside weather conditions from a central point has been developed by Thermocycle International. Outdoor temperature and humidity sensors called Rotronic Hygroskop sensors, can accomplish this task without any maintenance requirements or problems usually associated with wet bulb temperature sensors requiring water, such as freezing or loss of water. The Rotronic units are used in conjunction with a wet bulb computer, which psychrometrically deciphers the outdoor conditions, assuring that water cold enough for "free cooling" can be produced, thus eliminating the guesswork. Each unit's program is matched to the facility's tower performance characteristics to assure that the changeover point is correct. An alarm also alerts the operator that the outside air temperature is on the upsurge, and that it is time to change back to normal refrigeration. Resistance Thermal Devices (RTD's) measure the supply water temperature from the tower, to assure that the towers are performing as expected. The RTD's will alarm the operator of high water temperatures in time to switch back to normal refrigeration.

These same devices can be used to trigger the programmable controller to perform a changeover automatically. This feature is particularly useful at sites where operators are not available around the clock in the mechanical equipment room. The "free cooling" mode will be used to its fullest extent with the safety of knowing that if there is a failure on the part of the strainer, or the cooling tower cannot produce cold enough water, the system will automatically revert to normal refrigeration to assure a constant supply of chilled water to the load.

Hour meters and BTU meters can be employed to monitor the number of hours that "free cooling" has been utilized to date and to totalize ton/hours saved through "free cooling." This frees the operator of the burden of time-logging mode changes.

In some recent designs, the programmable controllers have been utilized for more than just changing from STRAINERCYCLE to normal refrigeration and vice-versa. For example, at the Banker's Trust facility in downtown Manhattan, the programmable controller decides upon one of four sources of cooling for the mainframe of a large computer system. It does this based on the outdoor conditions, and the tower supply temperature. It also controls the tower fans to provide the coolest water possible with a minimum number of fans based on outdoor temperature, humidity, and pre-programmed tower performance specifications.

At the same facility, the unit is programmed for failsafe changeover. If the strainer develops any operating problems, it will alarm and lock-out the strainer and revert to normal refrigeration. This feature clearly demonstrates the progress that has been realized in the evolution of "free cooling" as a safe system.

In case of power failure, the controller positions to a special sequence, utilizing a chilled water storage tank as the source of cooling.

At the Equitable Life building a custom sequence was designed to provide a second backup strainer in case of emergency to continue services to the computer floors on a segregated computer cooling system.

At this site, an absorption chiller was used to cool computer floors only; the risers were cut and capped to all floors above and a new expansion tank was installed on the altered system. The existing condenser and chilled water pumps were utilized in the redesigned system. Two strainers, each capable of handling the "free cooling" flow individually, were installed in-line with the condenser system. The control panel is programmed to monitor strainer operation. If one strainer develops an operating problem, it is automatically secured and the backup strainer is activated. An alarm sounds at this point to alert the operator of a problem.

It is necessary for an automatic strainer to discharge an amount of water to waste in order to clean its elements. An available option to the STRAINERCYCLE system is the Backwash Reclamation System. When either strainer backwashes, the effluent is dumped to a holding tank. It is then pumped through a centrifugal separator and clean water is reinjected into the condenser water return to the cooling tower. Debris is blown down to a drain with a water loss of less than a few gallons per blowdown. This feature minimizes water losses incurred by automatic strainer backwash. The holding tank is fitted with an alarm float that prevents further backwashing until the tank's liquid level is reduced to a point where another backwash volume can be accepted without overflow. Reclamation systems can also be designed to eliminate the holding tank, and reinject clean effluent at the same rate that it was discharged from the strainer.

Naturally, savings for computer facilities vary depending on local utility rates and weather conditions. The system's track record is excellent. As industries become increasingly computerized, their need for energy-saving systems will become even more critical.

ENERGY CONSERVATION FOR COLLEGES AND UNIVERSITIES

H. I. Collier
Director Of Physical Plant
University Of Houston

I have been in university administrative work for the past twenty years. For the first ten years, conservation of energy was of low priority because of its low cost. However, it has been of real concern for the past ten years because of the tremendous increases in energy cost.

As an active member and officer in the Association of Physical Plant Administrators, I have been in touch with what many universities and colleges are doing in managing energy. The report brought to you today reflects the experience of several universities, including the University of Houston, Louisiana State University, North Carolina State University and Western Kentucky University. I want to give thanks to my friends, Charles Braswell and Owen Lawson, at the last two universities for the help they have given me in my responsibilities and in the subject matter of this report.

Many universities and colleges, like a few industries are still not operating like there were a need for efficient energy management. To be successful, an energy management plan must have the full blessing and acceptance of the people involved. In our homes, this is usually not a problem because improper energy management results in higher utulity bills for us to pay. In small industries and commercial businesses, the owner or manager also has strong incentive to conserve energy in order to keep the costs down. However, sometimes in larger businesses the utility costs become lost in a maze of other cost data and no one becomes excited. Also, many universities and colleges are operating like they have no concern for utility costs. Lights and HVAC systems are on 24 hours a day throughout the year and energy is being thoughtlessly wasted.

There is a need for energy management in colleges and universities because energy costs continue to rise. On the other hand, enrollments are down or at a standstill, state budgets are being squeezed, research monies are harder to raise and overall college budgets are in an economic crisis. In many cases, today's cost of energy exceeds the total university budget of ten years ago.

An energy management program, to be effective, should be administered by a single individual or office. Splintering the responsibility among various colleges, deans, other administrators, serves only to dilute the total impact. Besides, these administrators have other important responsibilities, and are better trained for those responsibilities than they are to supervise an energy management program. Most colleges and universities place the overall energy management program under the Physical Plant Administrator, who is often a registered professional engineer and who is almost always a hard nosed businessman accustomed to dealing with difficult problems.

Designation of a single individual to administer the energy management program does not mean it is a one-person job - not by a long ways - because the program should involve the entire campus community. More will be said about this later on.

The individual responsible for administration of the energy management program needs to determine where the energy is used. Energy audits have become quite popular in recent years and serve as good tools for determining use of energy. However, there can be problems with energy audits:

1. Lack of metering devices

2. Attempt to secure more information than is needed

3. Time delays in getting information

If any of the above conditions exist, it might be well to consider a simple analysis to determine energy usage:

(1) Total amount of steam production by months

(2) Air-conditioning capacity, estimate of running time, by months

(3) Estimate of lighting usage, inventory typical of buildings

(4) Count of motors in operation and for what purpose - if information is already available

After determining where energy is used, then the manager can determine greatest potential for savings. Perhaps it is in lighting, or in heating, or in air conditioning. By concentrating initial efforts in the biggest areas of usage, the most productive energy conservation savings can be achieved. That is not to say the other areas can be forgotten. A couple of years ago, I was talking to a manager of a large petro-chemical plant about their energy management program. He was lamenting the fact that they could do nothing about energy conservation because the nature of their plant operation was such that two-thirds of total energy consumption was in plant operations and they had already tuned up their operation to maximum efficiency. However, their total electrical load was over 100 MW. Thus, the one-third electrical usage not associated with plant operations amounted to about 35 MW, hardly an expenditure that should be overlooked.

One of the responsibilities of the energy manager should be in the analysis of rate structures. Most rate structures include penalties for poor power factor. Many have different rates day vs. night usage, summer vs. winter usage, etc.

In most cases, electrical demand charges are set based upon maximum load at any single instance - thus a peak can inflate electrical costs for years to come. Even the date of reading meters can have a big impact on energy charges. At one time, the electrical meters at L.S.U. were read by the utility company late in August (the usual peak) where a high demand was recorded in the billing for August and September. By having them change the reading date schedule to a later time, savings of nearly $5,000/month were realized. Obviously, the utility company will not change their meter reading schedule every year, but it is certainly worth trying for a one-time savings of that magnitude.

Energy managers in universities and colleges and in industry have looked at various ways of managing energy. Obviously, the more traditional ideas have been implemented first, including:

1. Installation of more efficient lighting, fluorescent for incandescent, sodium or mercury vapor for fluorescent.

2. Adoption of realistic, more conservative lighting standards, or use of space lighting.

3. *Establishment of more conservative HVAC* standards, 65° - 70° in winter, 78° - 80° in summer

4. Turning off HVAC systems when buildings are not occupied

5. Use of more insulation in attics and on hot and cold water piping.

Although these traditional ideas helped, it was still necessary to dig deeper in controlling energy. One of the new techniques available was the use of computers for controlling equipment. This equipment became available about eight years ago and can cost from $150,000 to several million dollars and can be utilized for simply controlling air handling units to more sophisticated equipment which controls pumps, chillers, as well as air handling purposes. Today most universities and colleges have some sort of computer-controlled systems or are planning to install a system in the near future. The institutions that are using too little energy to justify such an expenditure are usually installing time clocks which are very effective in reducing energy usage in single buildings.

As energy costs have continued to rise and the "cream" has been "skimmed off" by traditional means, the energy manager has looked to more innovative methods of managing energy. Some of these methods have been possible by new technology and others have been the result of new thinking. Some energy conservation ideas coming from new technology and products include:

1. Use of solar film on windows

2. More efficient lamps for lighting

3. Installation of high efficiency electrical motors, often with pay-out of 12 - 18 months

4. Use of polarized lenses for light fixtures.

Other new energy conservation products are being developed each year, many of these now being shown at this exhibit. Obviously, it is necessary that all of us keep up with the new technology.

Other energy savings are being realized through a change in our way of thinking and the application of engineering techniques which were formerly not economically feasible. These techniques include:

1. Solar panels for heating and hot water
2. Pre-heating boiler feed water utilizing heat from flu gases and/or return water
3. "Free-cooling" of air conditioning systems in moderate weather, thus shutting down chillers
4. Use of sub-surface water for chilling water in HVAC, thus shutting down cooling towers
5. Enthalpy control of fresh air intakes for HVAC systems
6. Use of "air locks" at entrance doors to reduce loss of conditioned air

There are also administrative policies that can be adopted by colleges with minimum amount of investment, which can often be as effective in reducing energy consumption as elaborate engineering projects. Some of these administrative policies include the following:

1. Scheduling of night classes or Saturday classes into certain specific buildings, locking up the others at end of afternoon classes. Adoption of this schedule at L.S.U. several years ago resulted in savings of $200,000/year.
2. Changing holiday schedule to take advantage of reduced HVAC demands. Shifting of two work days out of L.S.U. staff work schedule between Christmas and New Years in 1981 resulted in savings of $85,000 and was continued in 1982.
3. Assignment of space by similarity of use and schedules rather than solely by academic departments.

   Implementation of this idea will require changes in faculty attitudes but can be very cost effective. Space assignment changes might include:

   (a) Centralization of computers, electron microscopes, and other scientific equipment requiring special environments.

   (b) Separation of faculty offices from classroom buildings so that latter can be shut down when classes are not in session.

(c) Centralization of libraries, computer I.O. rooms, foreign language laboratories in same building(s) so that these facilities can be available to students at nights and on weekends without other buildings being open.

Energy management programs usually result in some changes in the environment of an institution and will not go unnoticed by faculty, staff and students. These changes can result in strong resistance from the university (college) community if it is not prepared for the changes. Thus, the energy manager must secure cooperation of faculty, staff and students.

Some methods of gaining acceptance from the university community include:

1. Publicizing energy costs and impact on total university budget.

2. Appointment of energy liaison managers for each building to monitor energy waste--open windows, lights left on in empty offices and classrooms, etc.

3. Campus-wide contests for development of energy slogans, posters, etc.

In summary, an effective energy management program should include:

1. Designation of a single individual to manage the program

2. Determination of where energy is used so as to establish priorities in energy reduction programs

3. Implementation of energy management programs:

   (a) Traditional ideas

   (b) Use of computers, time clocks

   (c) Use of new technology

   (d) Use of more innovative engineering techniques

   (e) Changes in administrative policies, schedules and space assignments

4. Before the above programs can be successfully implemented, the cooperation of university community must be obtained.

Finally, the energy manager must stay abreast of technological changes and keep in touch with what other energy managers are doing. We must continue to improve in managing energy and not be satisfied with past achievements. Conferences, such as this one, are essential for continued improvement.

(1) Braswell, Charles C., "Saving Energy in Institutional Buildings." Heating, Piping, Air Conditioning (March 1982), 54-64.

(2) Collier, H. I., "Tame the Beast - Rising Energy Costs." National Forum - Phi Kappa Phi Journal (Spring 1982), 40.

PRICING FOR COGENERATION: A UTILITY PERSPECTIVE

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The cogeneration and small power production regulations promulgated by the Federal Energy Regulatory Commission under Sections 201 and 210 of the Public Utilities Regulatory Policies Act of 1978 have been subject to much controversy. Regulators and utilities have had difficulty arriving at uniform understanding of the Federal Energy Regulatory Commission's intent. In fact, it is fair to say that utilities, from one end of the country to the other, differ significantly in their interpretation of the Commission's regulations and the appropriate course of action to follow. At the present time, the matter is being contested at the highest level of the U. S. judiciary. There are, however, some aspects which can be agreed upon and others which cause the bulk of controversy.

In this presentation, I will address the current status of buyback rates, the controversy of avoided costs, reliability factors in the capacity credit, and the small power producer and cogenerator as partial requirements customers. I will attempt to place these items in their proper perspective. There is little doubt that utilities are now required to purchase excess capacity and/or energy from cogenerators and small producers. Many companies have standard buyback rates on file with the respective public utility commissions. Normally, there are two such types of rates. One rate will recognize the reliability and availability of the small producers' and cogenerators' equipment, while the other rate may recognize that some installations may not be able to provide any assurance of availability or reliability and, consequently, would provide energy only when the unit is running or when fuel is available for production of energy. Many utilities have a handful of customers supplying power to the utility on one or more of the standard buyback tariffs. It seems to me that the major controversy surrounding buyback tariffs is the concept of avoided costs. While the great debate over marginal cost pricing versus average cost pricing may have subsided somewhat, it is interesting to me that the respective foes have reversed roles and now fight over whether or not utilities should pay avoided costs or average costs. My own opinion is that there is too much to do about when avoided capacity costs should be paid and when they should not be paid.

The question of avoided costs has been overdone. If costs (avoided or otherwise) are separated by time of day, capacity and energy, I believe the controversy over the avoided cost question can be greatly simplified. Furthermore, the discussions can be reduced to avoided capacity costs during on-peak periods.

Where time-of-use rates based upon marginal cost are commonplace in the utility service territory, small producers or cogenerators can displace, during on-peak periods, full avoided energy costs, avoided generation capacity costs, avoided transmission capacity costs and a portion of the avoided distribution costs. Accordingly, the customer currently under these circumstances has an opportunity to displace the marginal cost for capacity which the commission permits the company to collect from its retail customers.

One might argue that the marginal cost allowed by the utility commission for retail ratemaking may be less than full avoided cost due to a revenue constraint. That may be true. On the other hand, retail tariffs include not only marginal generation cost but also marginal transmission cost and distribution cost. Even though each of these may be less than the full avoided cost, the sum of the three in almost every instance, I submit, will be equal to or greater than the full avoided generation cost. It is only for power generated on peak in excess of a customer's own needs where the question of avoided cost paid from the utility to the small producer or cogenerator becomes at all complicated.

I have simplified much of the deliberation on this issue because I have assumed that the utility has been committed to an aggressive program of marginal cost-based time-of-use rates for retail customers. Where time-of-use rates for retail customers recognize no capacity cost during off-peak periods, where off-peak periods are generally nighttime, Saturdays, Sundays and selected holidays, the complexity of dealing with the avoided cost is further reduced and our total effort can be concentrated on determining what those avoided costs may be during the on-peak period.

I made reference earlier to the great debate between marginal and average cost rate design. It seems to me at this point that many of the intervenors who argued vehemently against marginal cost pricing at the retail level have received some divine inspiration and are now championing the cause for full avoided cost as they have become small producers or cogenerators.

An extension of this approach to full avoided costing has recently come forth in the proposed establishment of a uniform buyback rate for groups of utilities. In the utility industry, the diversity between companies requires that avoided costs and buyback rates should be determined on a utility-specific basis and, furthermore, that they should be consistent with marginal cost calculations submitted to the regulatory commission in support of the utility's rates. Anything else would be inconsistent.

Let's focus a little more closely on the issue of avoided capacity cost. The question of excess capacity for purposes of determining avoided cost is a utility-specific issue. Furthermore, as indicated, it is related to the season of the year and the time of the day. A utility can claim it has excess capacity for the purpose of determining its avoided cost when its reserve requirements during the period in question equal or exceed the reserve requirements deemed necessary to provide reliable service, and when the addition of generation to the system by a small producer or cogenerator will have no bearing on the need for power either through purchase or capacity expansion during the period in question.

Assuming that the anticipated capacity addition and load growth during that ten-year period occur as planned, there should be no need to include any generation capacity credit in the buyback rate. If, on the other hand, the planned generation expansion plans of the utility can, in fact, be altered (deferred or eliminated) as a result of the small producers and cogenerators then, obviously, the contrary is true. There is a special case which may provide an exception to the above-mentioned rule. That has to do with the contracts for the sale and purchase of capacity to meet minimum reserve obligations. In this special case, there could be a credit given by one company for reduced purchase as a result of the energy supplied by the small producers and cogenerators. While this would not affect the buying utilities' customers, it would penalize customers of the selling utility.

Only a significant total of buyback generation could have an effect on reducing a plan to install generating capacity and, therefore, theoretically, there should be no credit given for very small amounts of buyback generation. That philosophy, however, might deter large numbers of small producers from entering the marketplace even though the aggregate amount which they could generate would be beneficial to the system and its customers; therefore, from the standpoint of conservation and efficient use of resources, there probably should be a credit given to encourage this type of generation, even for very small amounts.

It is not appropriate to give credit for transmission or distribution capacity-related cost where the purchase of power from small producers and cogenerators will not reduce such costs. The controlling factor is whether or not the utility is able to reduce the transmission and distribution investment costs in the future as a result of the small producer or cogenerator.

Reliability for the power supply source must also be considered in determining the appropriate capacity credit. There is another factor, however, which must be considered; that is, the availability of the small producer's or cogenerator's equipment, particularly with regard to fuel availability. For example, a windmill from a machine standpoint may be extremely reliable; however, from a fuel availability standpoint, it is only available for operating when the wind blows. The same is true of run-of-the-river hydro and of solar. The determination of reliability and availability of power supply from small producers and cogenerators must be determined on an individual basis.

In establishing standard buyback tariffs, a standard must be adopted which takes into account the degree of firmness and reliability of the small producer's or cogenerator's facilities. Obviously, such standards only apply if the small producer or cogenerator believes his facility qualified for a firm (capacity credit included) buyback tariff. In my opinion, to qualify under the firm rate the supplier should have to be able to assure the utility that his facility would be able to operate at a rated capacity 70% of the on-peak hours occurring in at least ten of the twelve calendar months. This is certainly not a rigid definition of firm capacity; however, the avoided capacity cost can be appropriately determined based upon this degree of firmness.

The rate itself will be a single kilowatt-hour charge for on peak and off peak. The capacity credit will be rolled into the energy charge on peak. Some customers, particularly cogenerators, may be sufficiently large and have peculiar circumstances which would warrant a different rate or contract from the standard form of rate on file with each utility commission. In those circumstances, the utility and the cogenerator have an opportunity to negotiate a special contract giving particular attention to the unique circumstances. Frequently, the subject of standby power, maintenance power, back-up power or supplemental power will be discussed in the context of a special contract. In essence, each of these terms suggests that the small producer or cogenerator will continue to be dependent on the utility for all or part of its power requirements some of the time.

Theoretically, the small producers and cogenerators described above have become a class of customers which are partial requirements customers. Theoretically, partial requirements service costs more than a full requirements service. The majority of our customers are full requirements customers and the installation of generation on an individual customer's property to supply a portion of their needs and return power to the supplying utility should not result in higher cost to the remaining full requirements customers.

One of the costs which may increase as a result of partial requirements customers, if not properly reflected in the rate to those customers, is generation capacity costs. When partial requirements customers enter the system, the supplying utility still has an obligation to provide all their requirements. When a utility projects its demand into the future and then plans capacity additions to meet that demand plus a planning reserve requirement, the utility calculates its reserve requirement based upon the load actually on the system, not the amount connected to the system. In the case of partial requirements customers who may generate 50% of their own requirements, but leave the utility the obligation to provide 100% of their requirements when and if their generation does not operate or they elect not to use it, the utility in order to maintain equal reliability must have additional reserves to cover the load supplied by the partial requirements customers. If the utility did not reflect these costs in rates to the partial requirements customers, the full requirements customers of the utility would either suffer a dimunition in the quality of service provided or pay higher costs. A similar argument applies to the transmission system.

In summary, the problems associated with cogenerators, small producers and their interrelationship with utility system will not go away overnight. Also there is very little additionally that regulators can do in the way of mitigating difficulty between supplying utilities, cogenerators and small producers. Regulators cannot do much in the way of affirmative action to encourage the development and use of cogeneration and small power production other than through appropriate pricing policies at the retail level as well as for buyback tariffs. Given the guidelines which FERC has established and the payment of avoided cost for this type of power production, market forces will act to encourage those technologies which can be installed and operated economically. In fact, the few regulations imposed upon the parties by the commissions, with the exception of safety, more likely ensure that alternative forms of generation from small producers or cogenerators will find a way in the marketplace. Those that do will provide benefits to owners of the facilities as well as the utility, its customers and its stockholders.

PACKAGED COGENERATION SYSTEMS FOR COMMERCIAL AND MULTI-FAMILY APPLICATIONS

Keith G. Davidson
Lawrence J. Kostrzewa
Gas Research Institute
Chicago, Illinois

Cogeneration is the sequential generation of both power (either electrical or mechanical) and useful heat from a single energy source. Although cogeneration has long been recognized as a potential energy-saving technique, its development has been hindered primarily by a combination of institutional barriers, historically low-cost energy alternatives, and the perception that cogeneration hardware is unreliable and has high maintenance costs. Recent technological advances, however, coupled with substantially increased energy costs and legislation that encourages cogeneration and small power plant operations, have spurred renewed interest in the cogeneration option by many private industries, utilities, and research organizations such as the Department of Energy (DOE), the Electric Power Research Institute (EPRI), and the Gas Research Institute (GRI).

Natural gas-fueled cogeneration can yield numerous benefits to the cogenerator, the general gas ratepayer, the natural gas utility, and the nation as a whole. These benefits accrue as a result of using our natural gas resource at a greater efficiency, thus supplying energy services at a lower cost. From the standpoint of thermodynamics, cogeneration sequentially matches the "quality" of the energy source to the needs of the task, thereby assuring optimal utilization of the full potential of the input fuel. It is the economic benefits rather than the thermodynamic benefits, however, that encourage the implementation of natural gas-fueled cogeneration. In many cases a cogeneration system is able to supply both electric and thermal energy services at a much lower cost than if they had been generated separately.

The environmental and strategic benefits of natural gas-fueled cogeneration are also significant. Increased efficiency of energy use alone results in decreased total thermal and material emissions, and natural gas is the most environmentally benign of all commercially feasible fuels for cogeneration. In addition, reliance on indigenous natural gas for electric and thermal energy services reduces pressures and risks involved with imported petroleum fuels, thus providing an important national strategic benefit. With the outlook for natural gas supply bright and the projections for future price reasonable, natural gas-fueled cogeneration should see continually increasing application.

The Public Utilities Regulatory Policies Act (PURPA), a part of the 1978 National Energy Plan, contains several incentives for cogeneration. The most important of these granted cogenerators the right to interconnect with the electric utility grid and to contract for backup electrical power at non-discriminatory rates. This paved the way for the current renewed interest in cogeneration because it eliminated the need for the cogenerator to purchase redundant equipment to ensure reliability or large amounts of under-utilized capacity for electrical peaking service. There are currently judicial challenges to the Federal Energy Regulatory Commission's rulings implementing PURPA, but it is likely these will be resolved to the satisfaction of both cogenerators and electric utilities. States whose electric utilities or public utility commission have taken a positive position on PURPA implementation are unlikely to be affected regardless of the outcome of these challenges.

Large industrial process heat applications are the cogeneration installations most commonly found today. Applications in the commercial and multi-family residential sectors are frequently overlooked or dismissed as infeasible, generally due to the more variable loads, fewer operating hours, and lack of economy of scale for small capacity units. Although these do present obstacles to economic use of cogeneration, there are several factors acting in favor of cogeneration in commercial and multi-family residential applications.

In general, retail electricity prices to commercial and multi-family residential customers are considerably higher than those charged to industrial customers nationwide. To a large extent, this can make up for the fewer operating hours seen in a commercial application. The large numbers of buildings in these sectors could permit factory assembly of standardized packages containing the engine, generator, heat recovery, and ancillaries. Economies of mass production could be even more significant than those of scale. These factors, coupled with the slightly longer payback periods considered acceptable in the commercial sector (3-5 years, as opposed to the 1-3 years typically required by industry), can make the economics fairly attractive. Financing, too, becomes less difficult due to the considerably lower capital investment required for these smaller systems. If desired, the $30,000-800,000 required can often be financed through retained earnings and debt from a commercial bank rather than the more complex third party or limited partnership vehicles.

In a system designed to meet commercial or multi-family residential heating and cooling loads, the electricity cogenerated will generally not exceed that required by the application. This avoids the often difficult and costly negotiation of purchased power agreements and uncertainty associated with future buyback rates. Commercial or multi-family residential cogeneration systems can be of benefit to the electric utilities since these systems will often only be producing power during the hours that correspond to the electric utility's peak and intermediate demand period rather than displacing low cost baseload power from coal or nuclear plants. The natural gas utility benefits as well because a gas-fueled cogenerator represents a summertime load it would not ordinarily have.

Although the economics vary widely from city to city, a cost-effective cogeneration system for commercial and multi-family residential applications will still need to operate for some 4000 full-load equivalent hours and achieve a high degree of utilization of waste heat. Unless a very large hot water heating load is found, it is necessary to consider the cogeneration system essentially as an HVAC system, supplying electricity, heating, cooling, and domestic hot water as required. As an HVAC option, cogeneration can be particularily attractive in the new and replacement market where displaced HVAC equipment costs may be taken as a credit. Total packaged systems, whose only installation costs entail site preparation and a few plumbing and electrical hookups, are a necessity for such HVAC applications to be cost-effective and reliable.

As an example, consider two hypothetical cogeneration installations, one industrial and one commercial:

	Industrial	Commercial
Application	Industrial Process	HVAC, Domestic Hot Water
Heat Utilization	100% process heating	30% space heat, 30% cooling, 20% DHW (80% total)
Operation	8000 full load h/y	4000 full load h/y
Installed Cost	\$700/kW	\$800/kW including chiller
Efficiency	25% electric, 75% overall	30% electric, 80% overall
Fuel	Natural Gas @ \$5.00/MMBtu	Natural Gas @ \$5.00/MMBtu
Electricity	5.5¢/kWh, \$8/kW/month	6.5¢/kWh, \$8/kW/month
Maintenance	1.0¢/kWh	1.0¢/kWh
Resultant First Year Savings	\$275/kW	\$210/kW
Simple Payback	2.6 years	3.8 years

Although greatly simplified, the example shows that commercial as well as industrial sector cogeneration applications can be an attractive means of reducing the cost of energy services. The reasons for this, as stated, are the higher electricity rates, more flexible payback requirements, and economies of production of system and components seen for smaller commercial sector applications. The two cases illustrated show what may be considered somewhat marginal returns. Increased operating hours or heat utilization could make the commercial application even more attractive. Higher electric rates would similarly shorten payback as would credits for replaced HVAC equipment. A necessary key to widespread implementation will be the availability of systems at or below the installed costs used above. This will, in most commercial applications, require the use of pre-engineered, pre-packaged cogeneration systems.

Packaged systems are attractive due to the advantages of full integration of all system components, optimized performance, single-source service responsibility and substantial reduction in installed cost resulting from mass production and pre-engineering. Economies of production can be carried even beyond component costs by mass producing the total packaged cogeneration systems, which eliminates the significant costs associated with non-recurring engineering, single-lot component purchases, assembly by untrained personnel, and reliability and maintenance problems caused by sub-optimal matching of components. Packaged system production also has the potential for reduced delivery times. In addition, production and use of standardized, tested and proven equipment will improve the reliability and maintenance costs of cogenerators, thus enhancing credibility with potential purchasers and with electric utilities, who may grant more favorable terms for the cogenerator.

The Gas Research Institute is supporting a significant research and development program aimed at the advancement of prime mover cogeneration technology for commercial and multi-family residential applications in addition to its participation in the onsite fuel cell program. Various prime mover technologies and applications are being considered, with emphasis on R&D that will lead to reductions in capital and operating costs and improvements in reliability and performance. The program will ultimately encompass research and development efforts in the areas of packaged systems heat recovery, controls, grid interconnection, thermal storage and chillers, and prime movers.

For the near term, the systems development activity is receiving the greatest emphasis and will yield several packaged, natural gas-fueled cogeneration systems up to 500 kW in size and producing up to 3 MMBtuh of recovered heat and/or 250 tons of cooling. This effort will include design optimization and prime mover and component adaptation into a system package that is targeted for a particular type of application. The approach to be taken includes tasks aimed at a detailed characterization of the class of applications to be considered, a definition of system specifications required to meet the application requirements, preparation of a preliminary design, economic and technical analysis for design optimization, followed by a final feasibility analysis. Four cost-shared contracts have initially been implemented for a conceptual design phase. Applications in hospitals, fast food restaurants, large commercial and office buildings, and multi-family residential complexes are being examined. For those concepts which show the greatest potential after the conceptual design phase, necessary development and testing will be conducted to provide realistic cost and performance data. Two of these efforts are discussed in more detail below.

GRI is working with Sievert Corporation, Dresser Industries and a major fast food restaurant chain to develop a packaged system with wide applicability across the U. S. Monthly gas and electric energy use data has been collected for over 1000 restaurants nationwide, supplemented by daily profiles acquired by metering several stores. Stores in 27 cities have been modeled on a modified Carrier E-20II HVAC program, which supplies input data to a program developed to compute cogeneration energy and cost savings. The optimal system at this point appears to be a high performance Waukesha 70 kW engine-generator set with heat recovery and a 30 ton absorption chiller. The system is being designed for unattended operation. A supplemental system (gas boiler or additional gen-set) may be required for extreme hot and cold days.

Economics and choice of supplemental system depend on local rate structure, climate and load profile, but preliminary results show savings of $15,000 to $30,000 per year and a 2-5 year payback for new and replacement applications respectively. Final conceptual design layouts and costing are currently being prepared for a full technical and economic assessment.

A similar conceptual design study directed at gas-fired cogeneration for hospitals is also moving towards setting optimal design specifications. Martin Cogeneration Systems, Inc. (a Caterpillar dealer) is working with several national hospital management organizations to acquire energy consumption data on new and existing hospitals. The greatest potential appears to be for a system aimed at hospitals in the 100-300 bed range, of which there are currently nearly 2,500. The hospital management organizations contacted are planning an additional 250 of this size in the next five years. Although existing hospitals are attractive for retrofit, new hospitals represent the best market due to savings in displaced equipment and the opportunity for easy interface. Involvement with hospital builders is planned in these cases to be sure cogeneration is factored into the design whereby maximum benefits can be otained. A system of approximately 400 kW capacity that supplies either hot water or 50-100 psi steam and absorption cooling appears optimal. All hospitals surveyed have full-time maintenance staff qualified on engine gen-sets, but unattended operation is still preferred. To allow ACRS depreciation of the equipment, external location of the system may be necessary. Noise is a critical concern and will be carefully addressed in the design and siting.

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EQUIPMENT & ECONOMIC CONSIDERATIONS FOR COGENERATION APPLICATIONS

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INTRODUCTION

The high overall fuel use efficiency of cogenerated power together with benefits of smaller disbursed generation are primary driving forces in favor of a more extensive application of cogeneration in the U.S. power supply.

Given the opportunity for the economic sale of excess cogenerated power, a wide range of plant design options becomes feasible for any given application. The following discussion considers combined cycle and conventional steam cogeneration plants, indicating how their relative financial measurements are effected by the plant type, size, configuration and variations in the economics of a particular application. The objectives of this presentation are: 1) to show under what conditions cogeneration is an economically attractive opportunity, and 2) to indicate a method for using the data to be developed to quickly assess the viability of any given application.

The thermal characteristics of power and process heat output are expressed in non-dimensional form, so that results may be generally applied to any application.

CYCLE CONFIGURATIONS

Figure 1 indicates the power/process heat characteristic "map" that is covered by state-of-the-art industrial heavy duty combined cycle and conventional industrial steam plants. It should be noted that the fuel consumption and power output corresponding to the maximum unfired combined cycle have been selected as the base parameters for the dimensionless heat to process (X) and power (Y) variables. This selection provides a familiar reference for these variables at any selected cycle design point.

The performance characteristics in figure 1 utilize gas fuel with appropriate allowance for combined cycle NOx control via steam injection. Coal fired conventional steam plant performance is also indicated.

The performance maps are not affected by the size of the gas turbines or absolute plant size at any point; however, the heat recovery steam system configuration changes as the borders of the thermal performance map (figure 1) are traversed. Line A-B-C constitutes a combined cycle with waste heat recovery while line D-E-F gives the characteristics with supplementary firing to 1400°F (~30% more fuel input). Although a process steam pressure of 100 psig is assumed, the range of process steam conditions typically encountered would only result in slight changes to the borders. Along lines A-B and F-E, the steam cycle is a non-condensing steam turbine with decreasing throttle steam bypass. Line A-F represents a gas turbine and boiler with steam sent directly to process (no steam turbine). Along lines B-C and E-D, condensing steam turbines with decreasing amounts of automatic extraction steam are incorporated. Line C-D gives the maximum condensing possible while still meeting the requirements to qualify for cogenerated power (PURPA)*.

The above discussion is also applied to the conventional steam cycles without the gas turbine. Since coal fired plants are required to meet only minimum process heat to qualify for cogenerated power under PURPA, their thermal characteristic covers almost the complete range as indicated in figure 1. The cycles of figure 1 are designed to produce the maximum power within the technical constraints of the state-of-the-art (SOA) technologies; thus, indicating an excluded X-Y region under the combined and conventional steam cycles. Cogen plant designs for these points are possible only by utilizing inefficient energy conversion which will not be economically attractive.

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*PUBLIC UTILITY REGULATORY POLICY ACT

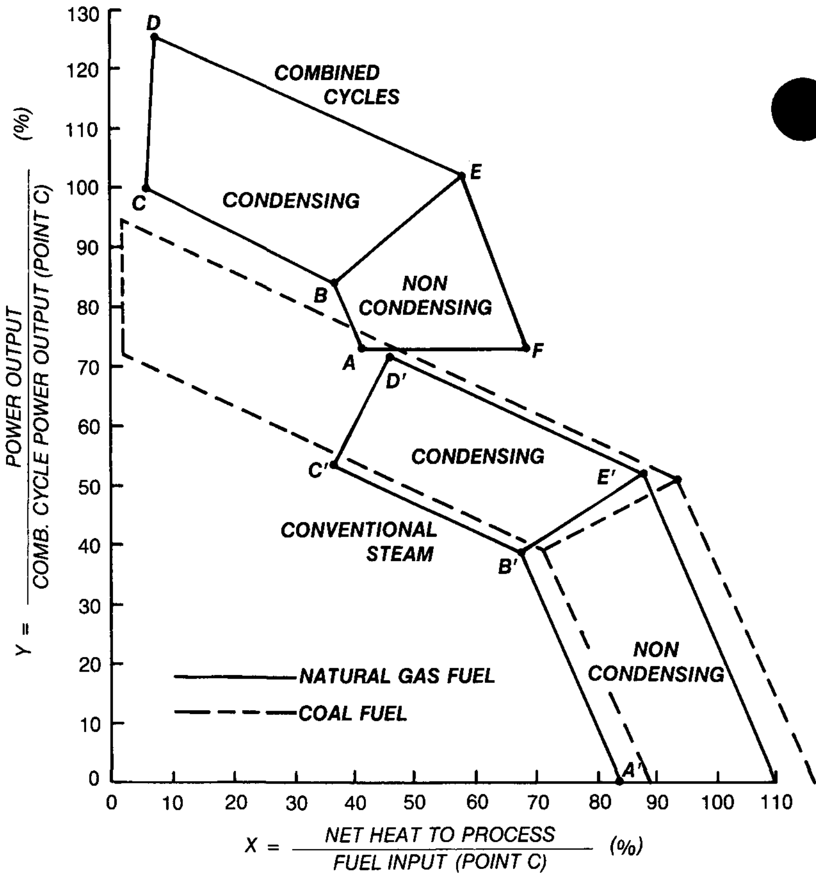

FIGURE 1 PERFORMANCE CHARACTERISTICS OF COGENERATION SYSTEMS ELECTRICAL OUTPUT VERSUS PROCESS HEAT

This evolution represents the various arrangements which would result in satisfying any particular cogeneration application. Any point within the map is a possible configuration and greater degrees of supplementary firing could be incorporated; however, practical steam turbine designs limit the configurations close to the noncondensing region (line B-E) due to the resulting small last stages and a practical degree of minimum firing would place actual designs in the map at some small distance from line A-B-C.

EFFICIENCY AND FUEL CHARGEABLE TO POWER

Figure 2 indicates the trend of the cogen heat rate, termed "fuel chargeable to power" (FCTP), corresponding to the maps of figure 1. FCTP is the cogeneration heat rate, adjusting fuel and power credits for the energy in the "useable" process heat and for differences in auxiliary losses with a no cogen boiler option. This parameter assigns the proper incremental fuel input to the power generated and is, therefore, a true measure of the cogenerated power efficiency. Figure 2 may be viewed as three-dimensional with the X-axis being replaced by the X (heat) -Y (power) horizontal plane and the Y-axis coming out of the page. It will be noted that the cogen heat rates are low, with noncondensing cycle FCTP only 50% to 60% of even very efficient combined cycle power generating plants and 40% to 50% of the most efficient conventional steam power plant. The FCTP increases significantly as the amount of condensing is increased, which is a result of the heat rejection in the condenser. Excess air loss in combined cycles is reduced with HRSG supplementary firing and, at lower levels of condensing, results in improved combined cycle efficiency (e.g., lower FCTP) as highlighted in figure 2 in the noncondensing region. It will be noted that conventional steam options have the lower FCTP potential since they avoid the higher excess air loss of combined cycles and approach the theoretical 3800 Btu/kw-hr (HHV) with gas fuel.

It is this high efficiency which provides the fundamental driving force for cogenerated power.

TOTAL INSTALLED COST

Figure 3 indicates the relative total installed cost variation of the options as the performance maps are traversed. The base cost used in figure 3 is that corresponding to the base combined cycle power plant defined in figure 1. Since plant size has a significant effect on economics, scale must be considered in overall trends. The magnitude of the base costs and performance are indicated in table 1 for various combined cycle size plants considered.

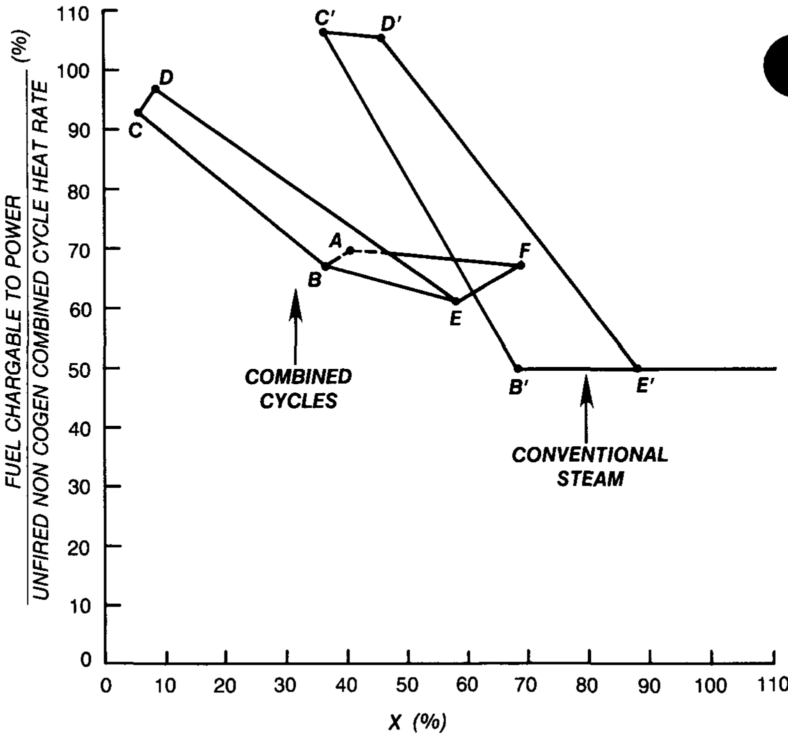

FIGURE 2 FUEL CHARGEABLE TO POWER VERSUS PROCESS HEAT

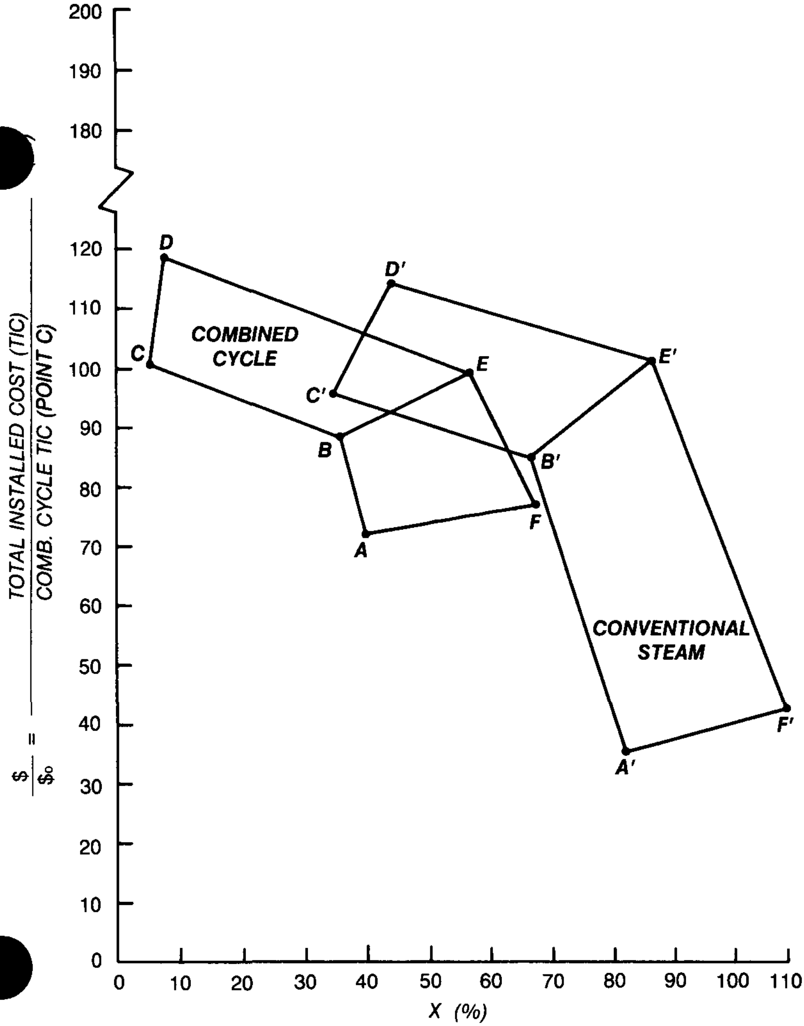

FIGURE 3 RELATIVE TOTAL INSTALLED COSTS VERSUS PROCESS HEAT

The costs are in mid-1982 dollars and include interest during construction and escalation to the beginning of operation. This data is used in the subsequent discussion of economic scale effects.

TABLE 1. COMBINED CYCLE COGENERATION PLANT DATA

RANGE OF PROCESS HEAT (10^6 Btu/hr)	20 - 160	30 - 320	60 - 700
BASE PLANT SIZE (MW)	27.8	51.2	105.4
BASE HEAT RATE (Btu/KW-HR)	9360	9080	8810
BASE INSTALLED COST ($/KW)	846	616	476

ECONOMIC CHARACTERISTICS

The performance maps and capital costs of figures 1, 2 & 3 may be utilized to establish the economic characteristics of the cogen options and study the trends of the key financial measurement parameters which determine project attractiveness. Key parameters are yearly net income (NI) and the return on investment (ROI).

The net income is established by the cash flows associated with fuel and O&M costs and the benefits derived from the savings and/or sale of steam and power. The resulting revenue and the associated capital investment determine the ROI. The revenue stream can be expressed directly in terms of the thermal performance coordinates of figure 1 with weighting factors accounting for the relative value of 1) steam, 2) power, 3) the installed cost factor (figure 3), 4) the economy of scale (e.g., table 1), 5) fuel cost and 6) cogen plant capacity factor.

The yearly net income is determined by the difference between revenues from the cogen plant, including a fuel credit for the production of process steam, and the costs to operate the facility. The investment is the total capital to install the cogen plant. Thus, the ROI represents the return possible on the total project when an existing process steam facility is replaced with a new cogen plant, as compared to continued operation of the existing facility.

In a grassroots' plant, an additional capital cost credit to install a new process steam facility alternate can be deducted from the cogen plant capital to establish the incremental cost of cogeneration. Net incomes will be the same as with an existing facility, but the resulting incremental ROI will be higher than that used in this analysis, particularly for the higher process steam (greater X) options. Thus, the full cost ROI to be subsequently used represents a conservative estimate for a given application.

Once the revenue stream is determined, the ROI is established by simple financial formula with the following assumptions:

- plant life = 20 years
- 100% equity financed
- equal inflation and escalation rates over study period
- ad valorem tax and insurance = 2.5% of T.I.C.
- depreciation life = 5 years
- investment tax credit = 10%
- federal and state income tax = 50%

The 51 MW base system of table 1 is used for the ROI calculation of figures 4 and 6; however, the percentage ROI changes due to fuel cost, power cost, or capacity factor will be the same for any size plant. It should also be noted that, since yearly hours of operation effects all revenue streams, ROI is proportional to capacity factor.

ROI and NI are particularly sensitive to the value of power (i.e. avoided power cost), cogen plant capacity factor and fuel cost. The value of power may be expressed directly in terms of an equivalent heat rate at which a utility could generate replacement power. This will be the actual utility heat rate if utility and cogen fuel costs are the same. The ROI maps should be visualized as surfaces in X-Y-ROI space, where the performance map of figure 1 is horizontal, the surface is viewed along the X-axis and the Y-axis points towards the reader.

DISCUSSION OF RESULTS

Figure 4 indicates the variation of ROI as the utility heat rate is decreased from 11,000 to 9,000 Btu/kw-hr, indicating a decrease of 7 to 10 points of ROI per 1,000 Btu/kw-hr in the equivalent utility heat rate for larger condensing configurations and about five points for the non-condensing options. The effect on conventional steam is smaller with a decrease of less than three points for noncondensing configurations.

It will be noted from figure 4 that gas-fired conventional steam plants can have attractive ROI; however, caution should be taken in direct comparison with combined cycles since, for a given process heat requirement, the conventional steam results in a significantly smaller plant which will decrease its ROI relative to a combined cycle. This is evident from table 2 and figure 7 where, for a process heat need of 410 x 10^6 Btu/hr, the difference

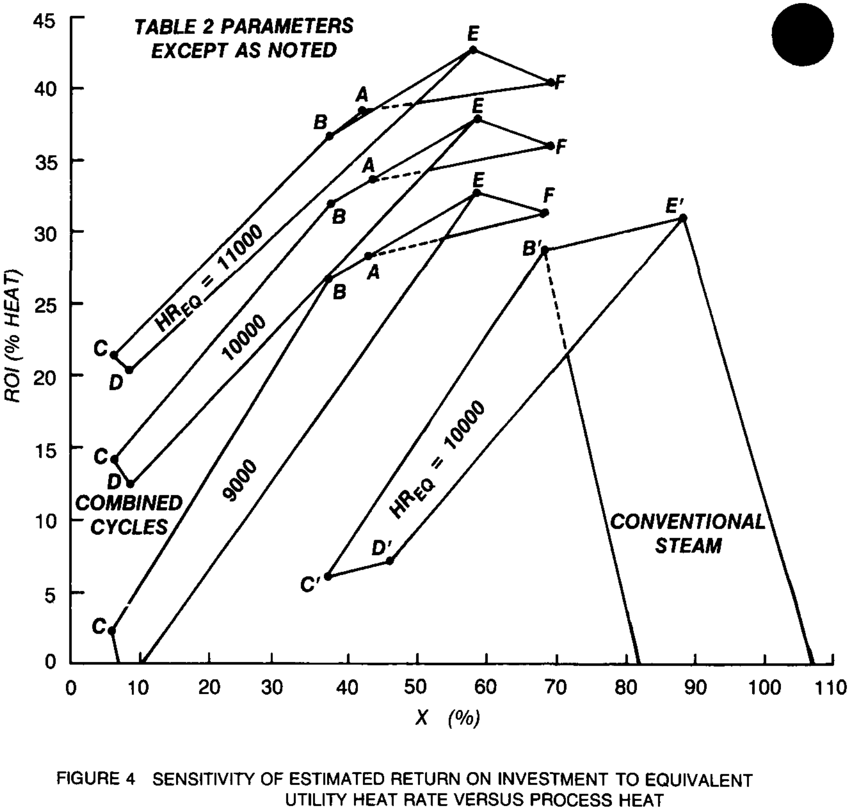

FIGURE 4 SENSITIVITY OF ESTIMATED RETURN ON INVESTMENT TO EQUIVALENT UTILITY HEAT RATE VERSUS PROCESS HEAT

in combined cycle and conventional steam ROI is more than 9 points (i.e. 25%).

The conventional steam plant offers the major advantage of considering the use of coal and/or lower cost fuels. Table 2 indicates the returns which result for several different cogen situations. Under the typical conditions indicated in table 2, a coal fired or combined cycle plant can replace utility power generated with premium fuels, with ROIs of over 40%. Gas fired conventional steam cogen plants can also achieve acceptable ROIs of over 30%. However, cogen options in situations where coal based utility power exists or where the cogeneration was already coal based result in much lower ROI and NI.

TABLE 2 COMPARISON OF SUPP. FIRED NONCONDENSING CYCLE

PARAMETERS:

Q_p = 410 x 10^6 Btu/hr - 8000 Hrs/yr of operation

Gas - \$6/10^6 Btu - 10,000 Btu/kw-hr Utility heat rate

Coal - \$2/10^6 Btu

COGEN CYCLE	COMB. CYCLE		CONVENTIONAL STEAM			
Utility Fuel	Gas	Coal	Gas	Gas	Gas	Coal
Current Process Plant Fuel	Gas	Gas	Gas	Gas	Coal	Gas
Cogen Plant Fuel	Gas	Gas	Gas	Coal	Coal	Coal
ROI (%/Year)	.405	<0	.311	.404	.237	.112
NI (10^6 \$/Year)	16.9	<0	9.93	25.3	14.8	7.0

The combined cycle cogen options at the minimum ROI (e.g., smallest X) will be larger, more costly plants but will return the highest net income. This trend, shown in figure 5, indicates that the highest net income per unit of cogen process energy occurs at the lower values of X.

In addition to ROI, a financial criteria requiring a minimum net specific income which must be achieved forms a boundary on possible cogen options. Note from figure 5 that such a criteria may eliminate the higher ROI combined cycle options and gas-fired conventional steam plant configurations.

Thus, to achieve higher net incomes, the condensing combined and coal fired conventional steam plants cycles are the cogen options to be considered. Capital constraints may be a determining factor in establishing

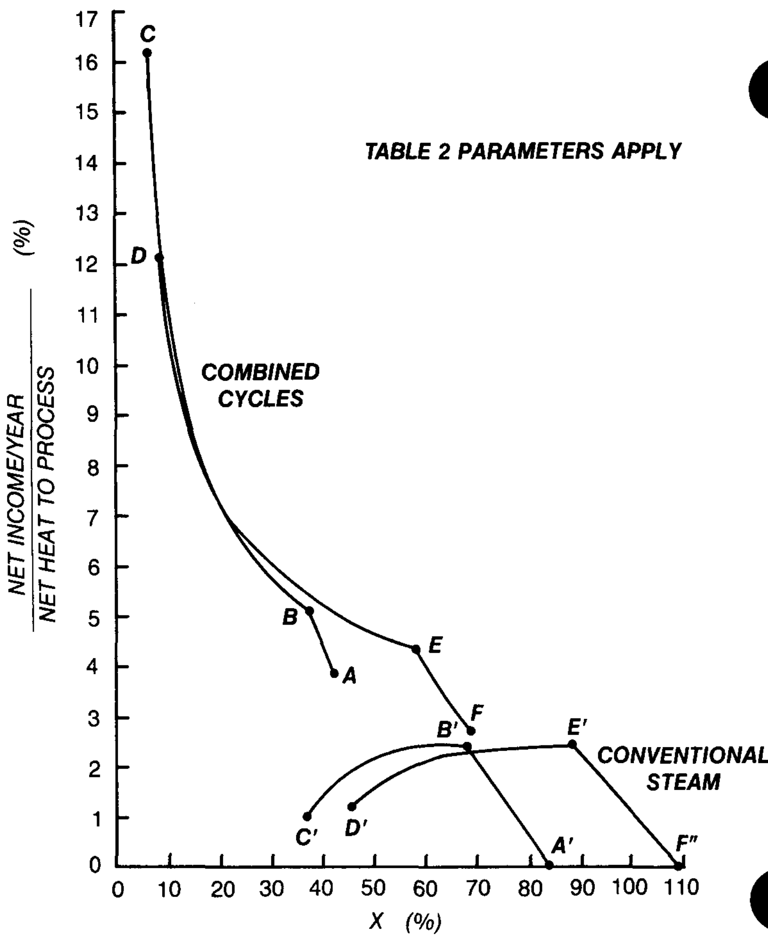

FIGURE 5 NET INCOME VERSUS PROCESS HEAT

the absolute plant size selected which will be subsequently addressed.

Figure 6 shows the influence of fuel cost on ROI. For cogen plants with the indicated size, capacity factor and utility heat rate, it will be noted that ROI can range as high as 45% for the noncondensing steam turbine option at $8/10^6$ Btu fuel costs and maintain attractive ROI at 30% for [illegible]00/10^6 Btu fuel costs. For premium fuels, the relative benefits of cogeneration in general become greater at higher fuel cost levels and the coal fired cogen plants become relatively more attractive.

Figure 7 indicates the effect of plant size or scale on the ROI of combined cycle cogen options. Cogen combined cycle plant sizes are indicated incorporating unfired and supplementary fired HRSGs. To quantify the various effects for a particular application, regions of specific process heat requirements are also shown in figure 7. For a given process heat load, higher values of X imply smaller plant sizes since Q_o, the turbine fuel input, is decreasing. At a Q_p level of 80 x 10^6 Btu/hr, the effect of going to smaller turbine size is to maintain about the same ROI. At higher process heat levels, the ROI can be improved with smaller units, since configurations evolve from the more expensive, less efficient autoextracting towards the lower cost, efficient noncondensing cycles. However, net income is reduced. At lower process heat requirements (e.g., 40 x 10^6 Btu/hr), the ROI is reduced and the smaller scale effect dominates over a wider range, significantly depressing the ROI at smaller sizes. It can be noted that the larger size plants are precluded at these low process heat levels due to PURPA limits.

It will be noted from figure 7 that a minimum process heat requirement is necessary to meet an acceptable minimum ROI for any cogeneration application. Given sufficient process heat needs to meet an acceptable ROI hurdle rate, the larger cogeneration plants result in the highest net income as indicated by the locus of net income which intersect the process heat bands. It will also be noted that, with combined cycle, unfired HRSG configurations result in highest ROI and NI for a given process heat requirement.

It should be noted that, if the magnitude of the risk capital is a constraint, the selection of the plant option for a given process heat, Q_p, will result in a higher value of X in figure 7 (e.g. smaller plant size). Such a capital constraint fixes the choice of X since, along the unfired Q_p curve (highest ROI), there is a unique capital requirement for each point. Providing this point meets minimum ROI requirements, it is the selection for the specific application.

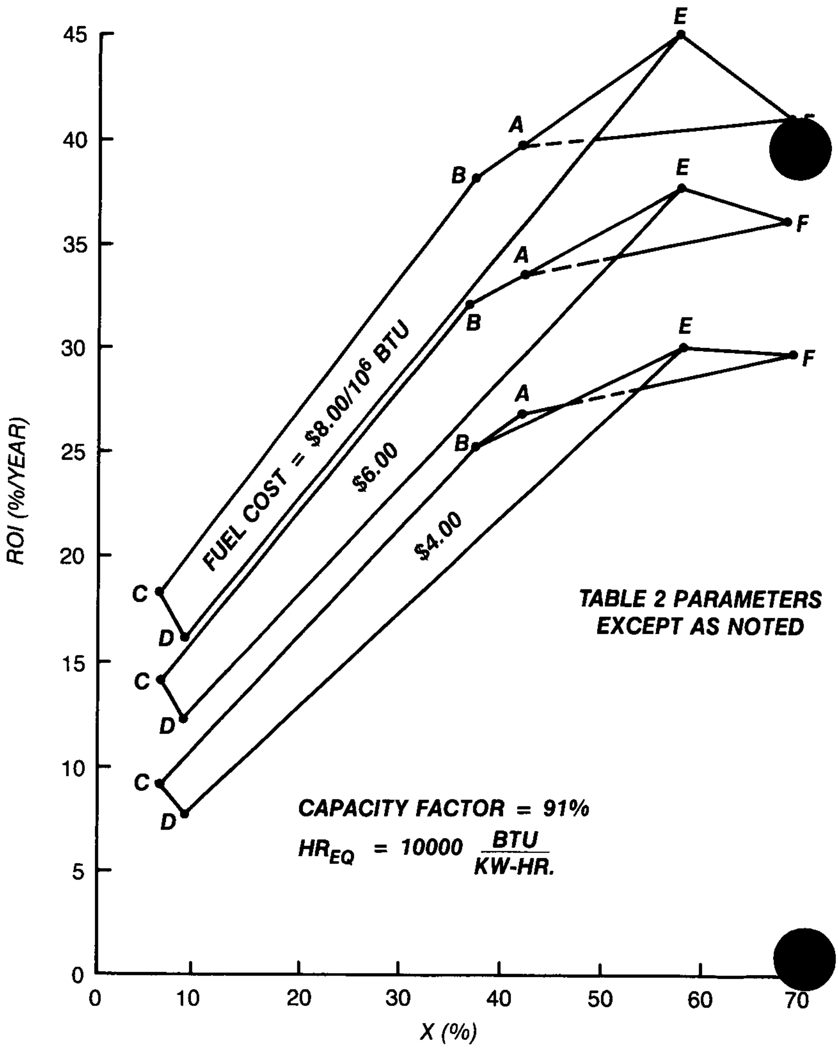

FIGURE 6 SENSITIVITY OF RETURN ON INVESTMENT TO FUEL COSTS VERSUS PROCESS HEAT

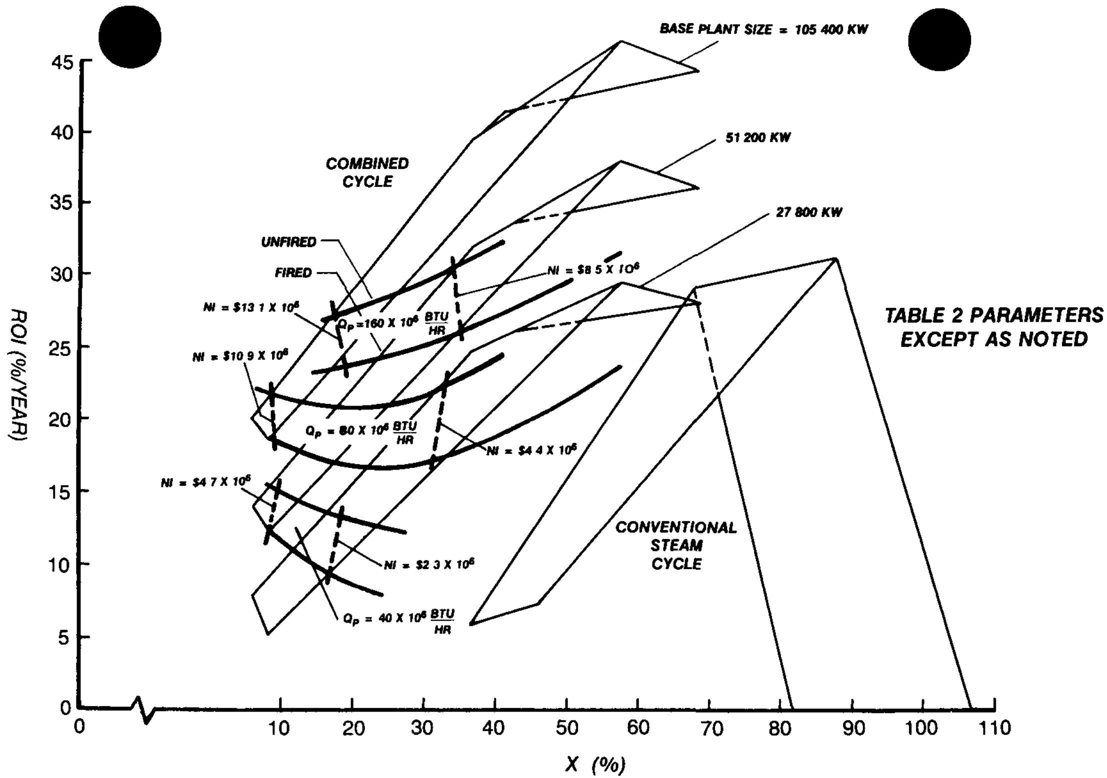

FIGURE 7 SENSITIVITY OF RETURN ON INVESTMENT TO PLANT SIZE VERSUS RELATIVE HEAT TO PROCESS

APPLICATION EXAMPLE

Figures 4, 5 & 7 may be used to approximate the ROI for a particular cogen application. Assume it is desired to know what the ROI would be for an application where: 1) process heat is 80 x 10^6 Btu/hr, 2) fuel cost is $8/$10^6$ Btu, 3) base loaded at 7000 hrs/yr for a site on a power system with a 4) 9500 Btu/kw-hr equivalent heat rate (7.6¢/kw-hr avoided cost) and it is desired to 5) realize the highest net income with this process need. Figure 7 indicates that a system incorporating a large size gas turbine (e.g., 105 MW base plant) with a condensing autoextracting steam turbine cycle and unfired HRSG would yield the highest net income and ROI for 80 x 10^6 Btu/hr. Note that the ROI is about 22% for the parameters of fuel cost, heat rate, etc., indicated in figure 7. This selection fixes the value of the X parameter at 9%. Figure 6 then indicates an approximate 12% ROI improvement for an increase of 17% (at X = 9%) in the fuel cost noting capacity factor affects ROI proportionately. However, figure 4 indicates a decrease of about 30% in ROI (at X = 9%) for the 5% decrease in the cogeneration utility heat rate. The approximate resulting ROI for this application with the selected plant would be:

$$22 \times 1.12 \times 0.7 = 17.3\%$$

The required investment is directly determined from figure 3 and table 1 noting at X = 9%:

$$I = \$/\$_o \times (\$_o/KW_o) \times KW_o = \$50 \text{ million}$$
$$(.99 \times 476 \times 105{,}300)$$

The net income is then:

$$NI = ROI \times I = .173 \times \$50 \text{ million} = 8.6M/yr.$$

Thus, all key parameters of the cogen plant design and returns may be established.

SUMMARY

Cogeneration affords opportunities for financially attractive projects in terms of fuel use efficiency, rate of return on investment and income.

This paper has shown how the performance characteristics of combined cycle and conventional steam plants change over the range of cogeneration applications and how the cycle configurations evolve under changing requirements. Nondimensional thermal performance maps generalize the results and reflect the relative technologies of the plant options.

Using thermal performance maps and capital cost trends, the sensitivities of ROI to key application specific parameters (e.g., avoided cost, fuel cost, scale, capacity factor, etc.) have been developed.

It has been shown that, for typical cases of cogeneration applications on power systems which utilize $\$6/10^6$ Btu premium fuels and where current power generation heat rates are approximately 10,000 Btu/kw-hr, a wide range of cogeneration options appear to meet attractive ROI targets ranging from 15 to 35% for 51 MW combined cycle base size plants to 20% to 45% for 105 MW base size plants. Those plants having the greatest net income with the highest ROI are the larger combined cycles with auto-extracting condensing steam systems and unfired HRSGs.

With sufficient process heat requirements and avoided power cost levels, economic benefits may be distributed such that cogen power can be produced at or below current rates which would allow for attractive return on investment to all parties. Power cost to utilities using premium fuels can be lower than the utility could generate with existing plants.

The comparison of conventional steam with combined cycle cogen plants shows that, where similar high grade fuels are used, combined cycles result in significantly better ROI and net income potential for the same process heat requirement. However, when a coal fired conventional steam plant is considered, its' return appears attractive compared with gas fired combined cycle options. This may suggest that coal gasification combined cycle cogeneration options could be a very competitive future concept in such situations.

Finally, the methodology and figures indicated in this paper may be used to determine the preliminary viability of cogen opportunities and develop data on the type, size, performance and cost of selected cogeneration plant options.

HOME COGENERATION SYSTEM CAN AUGMENT PEAK POWER REQUIREMENTS

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ABSTRACT

This paper discusses a home cogeneration system based on the principle that the peak power generation requirement of a utility company occurs at the same time of day that residential areas require both electric power and heating.

The proposed system will use known technology that is similar to turning on the heating system in your car as you drive around on a cold day.

The system will use small induction a/c generators excited by power company supply lines, eliminating the need for over/under frequency protection and over/under voltage protection. There is also no need for expensive synchronizing controls. The paper also discusses ways of eliminating alternators, starters and batteries.

INTRODUCTION

Cogeneration is very popular in the industrial world today. The same principle of cogeneration can be applicable, indeed profitable, to the homeowner. In the following pages a home cogeneration system will be described along with a discussion of:

- the technology
- the availability of equipment
- a proposed system description
- the economics of such a system
- a few special aspects of home cogeneration systems to reduce cost and improve efficiency of power production
- potential problems

Cogeneration, in the simplest sense, is based on the principle that the efficiency of electrical power production can be dramatically improved by putting heat wasted by prime movers to useful work, such as for home heating.

Conventional prime movers such as internal combustion engines, diesel engines and gas turbines convert only 1/3 of their fuel input to useful shaft power; the remaining 2/3 is wasted. In the case of natural gas, diesel or gasoline engines, for every gallon of fuel burned, the following approximate energy balance applies:

Total fuel consumed by the engine

= 1/3 energy used as shaft horsepower output + 1/3 energy rejected to jacket coolant + 1/3 energy rejected to exhaust gases.

Normally, in areas where the weather is cold, residential peak power requirements occur in the early morning and evening hours; it is during these same hours that home heating requirements are highest. It is this principle that can be put to use to supplement peak power generation by the use of I.C. engines around homes. This does not preclude power generation during non-peak hours of the day if heat energy is needed to heat homes, swimming pools, etc.

The technology to do this has been around a long time; it is just a matter of getting the government, the general public and the utility companies to work together.

USE OF INTERNAL COMBUSTION ENGINES AROUND HOMES, FARMS AND SMALL BUSINESSES

An internal combustion engine--the automobile engine is the prime example--can use gasoline, natural gas, or propane as fuel. A diesel engine works on the same principle but does not require spark plugs.

Turning the heater on in an automobile while the automobile is cruising on a freeway is an example of simple cogeneration: radiator rejected heat is partially recovered to heat the inside of the automobile for passenger comfort. In an average size home, if enough radiator heat can be recovered to heat the house, the amount of electric power produced at the same time is 10 times or more than can be used in the same house. This electric power can then be sent to the power company lines, forcing the power company to reduce or back off power company generator output.

GENERAL ARRANGEMENT OF THE SYSTEM

The arrangement consists of the following parts as shown in Figure 1:

1. I.C. (internal combustion) engine.

2. Engine radiator (remote mounted) and blower mounted inside the central air heating duct, or a heat-exchanger type radiator that rejects heat into water.

3. Inlet and outlet lines to and from the radiator. (The inlet to the radiator should be well insulated.)

4. Thermostat inside your home connected to the starter circuit of the I.C. engine.

5. "Critical" muffler for the engine exhaust system for noise reduction.

6. Induction generator (driven by the engine). An induction generator is a squirrel cage induction motor. Single phase induction generators are also offered by some manufacturers.

7. Reverse power relay (to prevent the flow of power from the power company grid to the induction generator). This may not be required.

8. Starter-contactor with overloads and start/stop pushbuttons to engage and disengage the induction generator. Over and/or under frequency protection may not be required. However, over and/or under voltage protection may be necessary.

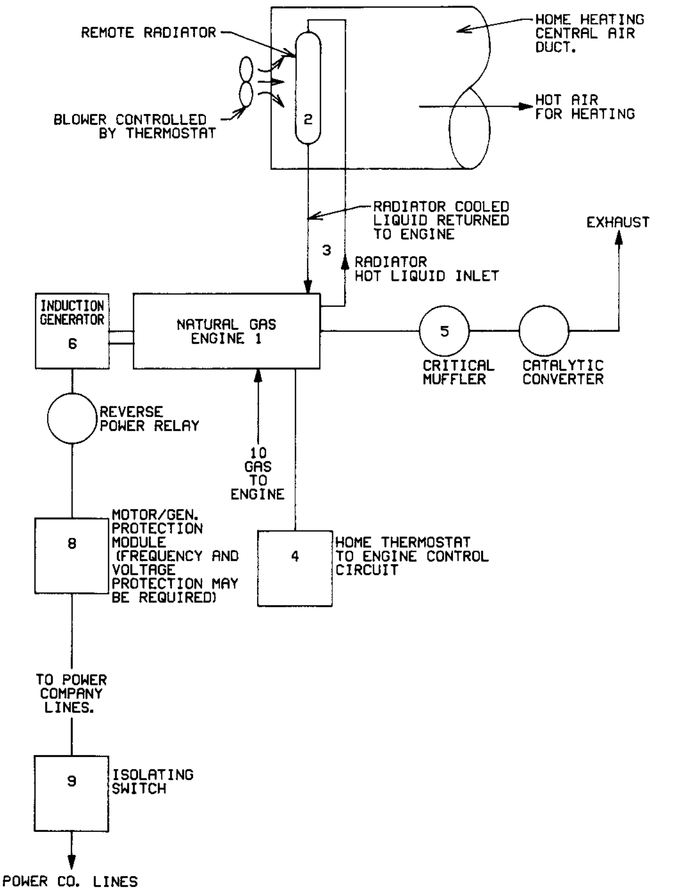

FIGURE 1
PROPOSED SYSTEM
BLOCK DIAGRAM

9. Isolating switch or breaker to isolate the power company line from the induction generator.

10. Appropriate fuel tank and fuel/gas lines.

RADIATOR COOLANT LINE

The hot coolant line going into the remote mounted radiator should be well insulated. The coolant temperature is around 180° to 190°F. The return line can be uninsulated.

THE GENERATOR

<u>Synchronous generators are not recommended</u> since such generators are difficult to synchronize with the power company frequency and require expensive controls. Induction generators are recommended due to simplicity and cost although they are less efficient compared to synchronous generators.

INDUCTION GENERATOR PROTECTION PACKAGE

This package is simply a wall-mounted combination starter equipped with either fuses or breakers. The package can also be made part of the engine controls and can be furnished by the engine manufacturer. The starter package can be equipped with relays required for the home thermostat to start and stop the engine. Since the starter has main contactors that open or close depending upon whether the engine is stopped or running, the possibility of the induction generator becoming a motor does not exist. The utility company power lines are connected to the induction generator only when the gas engine starts. This occurs only when the thermostat turns on. The starter contactor should be wired to open as soon as the engine stops. This will effectively cut off the "motoring" power from the utility company power lines to your induction generator. Because of this suggested arrangement, a reverse power relay may not be required. The reverse power relay is normally required to prevent "motoring" action. The same function is accomplished by opening the starter contactor when the engine stops or its speed varies considerably.

SWIMMING POOL HEATING

If natural gas is being used for heating a swimming pool, the cogeneration principles explained earlier are applicable. Since swimming pools require large amounts of heat, the use of swimming pool heating to produce electricity is practical and cost effective when engine/generator sets are used.

THE ADVANTAGES OF SUCH A COGENERATION SYSTEM

The following advantages are obvious:

- A substantial reduction in the amount of fossil fuel required to generate electrical power
- A substantial reduction in the other methods of electrical power generation
- A substantial reduction in "global" pollution
- A new industry to produce such systems simply and inexpensively
- A new service industry to support such home cogeneration systems
- Less dependence on foreign oil

THE DISADVANTAGES AND POTENTIAL PROBLEMS OF SUCH A HOME COGENERATION SYSTEM

- Although "global" pollution is reduced, pollution caused by such internal combustion engines is dispersed around a wider area in the residential neighborhood. Such pollution should be balanced against the normal fire-place pollution in residential neighborhoods. One way to combat such internal combustion engine pollution is by the installation of catalytic converters.
- High capital cost may be a discouraging factor. If such systems are well packaged, however, the capital cost will be around \$250 to \$300 per KW not accounting for any applicable tax credits.
- Homeowners well acquainted with the problems of owning a car may be put off by the maintenance problems associated with home cogeneration.
- The most important disadvantage is the potential problem with power company inter-tie. Some of those problems are:
    - Generator excitation by system capacitors when there is power failure. To prevent such self-excitation, protective schemes will have to be devised to isolate the generator from the power grid.

- The effect of a very large number of small induction generators switching on-off frequently along with a small number of very large synchronous generators operating continuously is unknown at present. Theoretic studies should be conducted along with experimental verification to evaluate the performance of infinitely large numbers of induction generators.

- Transients generated by on-off operation may create "noise" on communication systems such as T.V. reception.

- Use of induction generators in the motoring mode to start the engine may require special generator design to provide high starting torque to the engine. (This method is being suggested to eliminate starting motors for the engine.)

HOW TO DETERMINE THE ECONOMICS OF SUCH HOME COGENERATION SYSTEMS

Let us make the following assumptions:

- Cost of natural gas is 50¢ per therm or $5/MMBTU

- Cost of electric power <u>from</u> the power company is 11¢/KWH

- Cogenerated power cost of selling <u>to</u> the power company is 8¢/KWH

Let us consider a 2,000 square foot home with a central heating furnace with a capacity of 150,000 BTU/Hr. Let us assume that this home consumes 1.5 KW for 8,000 Hrs/Year.

From the preceding assumptions we come up with the following:

Total Fuel Used = Fuel for heating the home (radiator losses) + fuel for producing electric power + heat lost through the exhaust, etc.

= 150,000 BTU/Hr + 150,000 BTU/Hr + 150,000 BTU/Hr (approximately)

= 450,000 BTU/Hr

Total Fuel Used/Yr = 450,000 BTU/Hr x 3,000 Hrs/Yr

= 1,350 million BTU

Total Electrical Energy Used/Yr = 1.5 KW x 8,000 Hrs/Yr = 12,000 KWH/Yr

Total Electrical Energy Sold to the Power Company = 45 KW x 3,000 Hrs/Yr = 13,500 KWH/Yr

	Present Gas & Electric Bill	Proposed Gas & Electric Bill & Projected Income
Electricity @ 11¢/KWH for 12,000 KWH per year	- 1,320.00/YR	- 1,320.00/YR
Natural Gas Heating Cost @ $5/MMBTU, @ 150,000 BTU/Hr., 3000 HRS/YR, 0.75% heating efficiency	- 3,000.00	0
Income Received from Selling Power to the Power Company @ 8¢/KWH, 135,000 KWH/Yr	0	+ 10,800.00
Cost of Natural Gas for Engine Generator Set @ $5/MMBTU, 450,000 BTU/Hr, 3000 HR/YR (1350 MMBTU x $5)	0	- 6,750.00
TOTAL	- 4,320.00	+ 2,730.00

Notes:

1. -ve signifies your outflow of dollars (expenses).
2. +ve signifies your inflow of dollars (income).
3. Yearly maintenance costs are not shown.
4. Equipment cost is not shown.
5. Energy tax credit, depreciation, sales, taxes, if any, are not shown.

Net Savings = +2,730 - (-4,320) = $7,050/Yr

For small homes requiring less heat or those requiring heat only for short periods of time during short winter months, the numbers should be reduced proportionately. In a farm, exhaust from the engine-generator set can be used to heat animal houses and greenhouses, which would increase net income substantially.

The capital cost for such a system would be around $10,000 or approximately $250/KW.

SPECIAL ASPECTS OF HOME COGENERATION SYSTEMS USING ENGINE GENERATOR SETS

Certain aspects of engine generator sets (using induction generators) are worth special consideration to reduce cost of equipment, reduce weight and improve the efficiency of the engine. These aspects will be considered in light of engine generator sets being electrically connected to power company electric supply systems through home service entrances.

Use of induction generators makes it unnecessary to install synchronizing equipment, automatic transfer switches and frequency relays. This will reduce the cost of engine generator systems substantially. Since the power company line frequency will excite the induction generator, there is no need for frequency relay protection schemes. Also, since the power company line voltage maintains the induction generator voltage, there is no need for voltage regulators or under/over voltage relays. Sometimes certain companies require that over/under voltage protection be provided.

Since the engine generator will be automatically "engaged" with the power company's electrical system, the battery and alternator can be replaced with a solid state bridge rectifier system with no rotating parts. This will not only reduce maintenance on the alternator, but will also increase the efficiency of the engine (by a fraction of a percent) since the engine does not have to provide power to the alternator.

The next consideration is that of the engine starter. The engine starter can be eliminated, reducing equipment cost and weight. This can be accomplished by running the induction generator as a motor during starting. It may be necessary to oversize the motor for high starting torque required by the engine.

Since electronic fuel injection systems do, in general, improve mileage in cars, electronic fuel injection systems can be put to effective use to improve power generation efficiency of home cogeneration systems using engine generator sets.

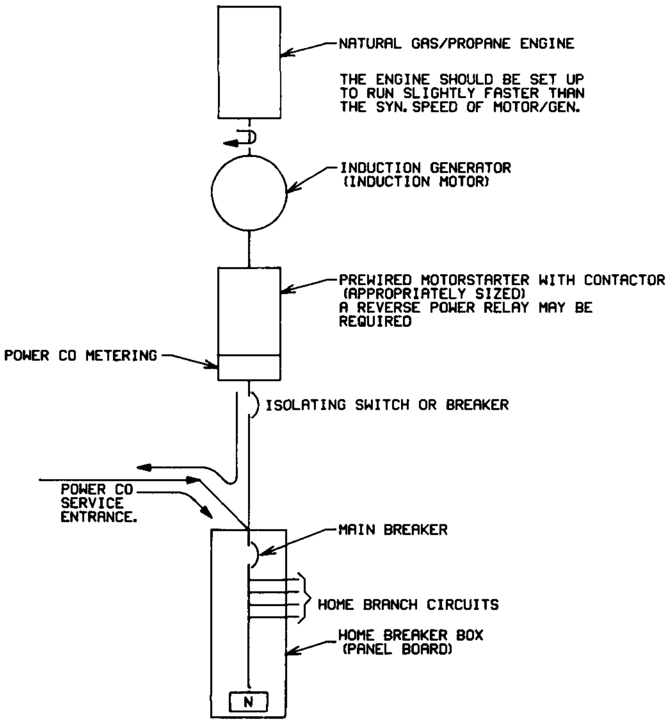

FIGURE 2
ELECTRICAL ONE LINE

TABLE 1

2 CYLINDER GAS ENGINE
PERFORMANCE DATA
(WATER COOLED ENGINE)

TITLE	BTU/HP	% OF TOTAL
HEAT INPUT	7,200 BTU/HP	100%
SHAFT OUTPUT	2,545 BTU/HP	35.4%
HEAT REJECTED TO RADIATOR COOLANT	1,700 BTU/HP	23.6%
HEAT REJECTED TO LUBE OIL	460 BTU/HP	6.4%
HEAT REJECTED TO EXHAUST	2,095 BTU/HP	29.1%
RADIATION LOSSES	400 BTU/HP	5.5%

NOTE: 1HP = 746 WATTS
= 0.746 KW

TABLE 2

4 CYLINDER GAS ENGINE
PERFORMANCE DATA
(WATER COOLED ENGINE)

TITLE	BTU/HP	% OF TOTAL
HEAT INPUT	7,700 BTU/HP	100%
SHAFT OUTPUT	2,545 BTU/HP	33.05%
HEAT REJECTED TO RADIATOR COOLANT	2,200 BTU/HP	28.6%
HEAT REJECTED TO LUBE OIL	450 BTU/HP	5.8%
HEAT REJECTED TO EXHAUST	2,300 BTU/HP	29.9%
RADIATION LOSSES	205 BTU/HP	2.6%

NOTE: 1HP = 746 WATTS
= 0.746 KW

Since diesel engines have approximately 2 to 3% higher efficiency than comparable gas/gasoline engines, the power generation efficiency of home cogeneration systems can be improved by the same percentage points by using diesel engines. However, this has the attendant disadvantage of higher noise and having to provide storage tanks and pipe lines for the engine fuel. This may still be appropriate in farms and in rural areas with existing fuel tanks for farm machinery, when additional noise is not objectionable.

Table 1 and Table 2 show typical efficiencies of two cylinder and four cylinder galoline engines, respectively.

INTERCONNECTION REQUIREMENTS IN NEW YORK STATE

by

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INTRODUCTION

The interconnection of dispersed storage and generation (DSG) devices with electric utility distribution systems raises new issues related to equipment and personnel protection requirements and associated costs. Current equipment protection and personnel safety policies have evolved from the concept of centralized generation of power and the delivery of power to dispersed loads. Most distribution systems provide a radial unidirectional flow of electric power from substations to the dispersed loads. The interconnection of DSG facilities to the distribution system alters the unidirectional properties of the distribution system. Matters of particular concern include: problems associated with backfeeding power into the utility system, such as the feeding of system faults; startup transients; DSG-generated harmonics; DSG-induced voltage fluctuations; and accidental isolation of one or more DSG installations on a utility circuit feeding other customers.

Requirements that deal with these concerns will affect the utility, its customers and the DSG developer. In New York, the costs of meeting the protection and safety requirements will be borne by the DSG developer and can affect the economic viability of a DSG installation. This paper discusses DSG technologies and examines the New York regulatory environment, technical requirements of the utilities in New York, and costs associated with typical requirements. Conclusions are then drawn which relate the economic impact of interconnection requirements to total project costs.

DSG TECHNOLOGY

DSG technologies which are anticipated for use within the next fifteen years include: solar thermal electric, phototvoltaic, wind, battery storage, fuel cell, hydroelectric, and cogeneration. Those already in use or considered to have significant near term potential in New York include wind, hydroelectric, and cogeneration. The current capital costs, including interconnection equipment, of installing these near term technologies in New York State are presented in Figure 1 (1).

Wind driven generators may be alternating current synchronous or induction, variable frequency, or direct current designs. For the variable frequency and dc generator output to be connected to the distribution system, a converter is required to provide power at suitable distribution system voltage and frequency. Electrical ratings of wind turbines being installed today in New York cover a range of 2 to 100 kW . The expected development of wind generation capacity in New York by 1996 is 60 MW (2).

Hydro driven ac generators may be either synchronous or induction. Hydroelectric installations can vary from a few hundred kW to tens of MW. The expected development of hydroelectric generation capacity in New York by 1996 is 1560 MW (2).

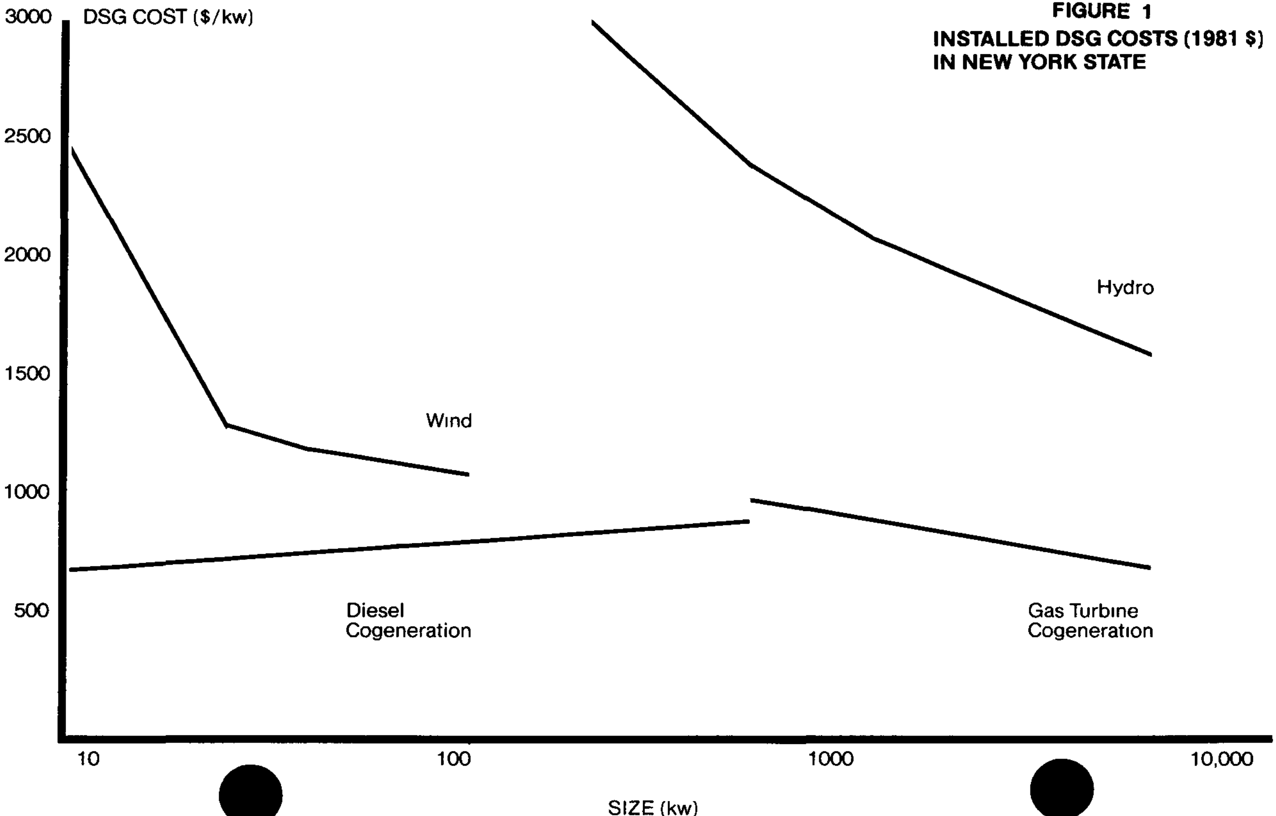
Cogeneration facilities most commonly use synchronous generators. Unit sizes may range from tens of kW to tens of MW. The expected development of cogeneration capacity in New York by 1996 is 860 MW (2).

The DSG power output rating will affect the location on the distribution system to which a facility is connected. Small DSG units (2 to 100 kW) may be at residential or commercial locations connected to single- or three-phase lateral circuits and secondary circuits. Medium-sized DSG units (100 kW to 1 MW) may be connected at commercial or small industrial locations on primary feeders. Large DSG units (1 to 30 MW) may be located at the distribution substation or on larger primary or dedicated feeders. The approximate upper power rating for DSG applications on distribution systems is 30 MW.

REGULATORY ENVIRONMENT

The Public Utility Regulatory Policies Act of 1978 (PURPA) made explicit a national policy of encouraging cost-effective cogeneration and small power production.

FIGURE 1
INSTALLED DSG COSTS (1981 $)
IN NEW YORK STATE



The U.S. Supreme Court upheld the constitutionality of PURPA in a decision issued in June 1982. The N.Y. Public Service Commission (PSC) issued a final Opinion and Order in May 1982 (3) which set forth rules and regulations under PURPA which require New York utilities to: 1) interconnect with cogenerators and small power producers; and 2) develop buyback and standby tariffs based on "avoided" i.e., marginal costs. In so doing, the PSC asserted jurisdiction in New York that makes irrelevant the outcome of the challenge to Federal PURPA regulations currently pending before the U.S. Supreme Court. Additionally, in 1981, the N.Y. Legislature amended the Public Service Law to establish a base price for buyback rates under PURPA at 6¢/kWh. These legal and regulatory activities have cleared the way for the development of a potentially large market for non-utility electric capacity in New York.

However, at least one significant barrier remains: the uncertain costs of interconnection. In its Order, the PSC declined to establish interconnection equipment standards. The result is that DSG developers must negotiate agreements with utilities on a case-by-case basis. Additionally, the PSC Order requires DSG developers to pay for all interconnection equipment and related costs, including engineering and feasibility studies conducted by the utility as well as reinforcements to utility substations and distribution systems necessitated by the introduction of DSG facilities. These costs can represent a significant fraction of project costs for small DSG installations. They can spell the difference between a profitable project and a losing one for medium-sized facilities.

This situation presents uncertainties to DSG financiers, entrepreneurs, and developers who want to do business in New York. These uncertainties concern: 1) varying types of protection equipment that may be required by utilities; 2) varying interconnection costs that the DSG developer may have to bear; and 3) resultant ignorance of the relationship between interconnection costs and total project costs that will have an effect on the balance sheets of different types and sizes of DSG facilities.

NEW YORK UTILITY INTERCONNECTION REQUIREMENTS

Guideline bulletins have been developed by each utility in New York to describe general requirements for protection systems with customer owned DSG equipment. The theme of the guidelines is that the protection system will: ensure public safety, maintain quality of service for other customers, protect utility employees, and protect utility and other customers' equipment. Established utility practices regard protection as the major concern and cost secondary.

Table 1 presents a compilation of the interconnection requirements of New York utilities that are published in guidelines and bulletins available to the public (4) (5). Variations in the requirements can be the result of differing protection philosophies and the degree to which the published requirements have been developed. The following points summarize generic interconnection requirements in New York:

(1) The utilities reserve the right to review and approve the proposed generation and protection system prior to installation and operation. Functional tests may be required with utility personnel present to witness these tests prior to operation.

(2) The utilities require the customer to keep maintenance records and reserve the right to inspect the records and the installation. Maintenance intervals may be specified by the utility for customer-provided protective devices.

(3) The utilities require the customer to provide, install, and maintain a lockable disconnect switch accessible to the utility and secured with a utility lock. The utilities reserve the right to open this disconnect switch without prior notice to the DSG owner for any of the following reasons: emergency conditions on the utility system; inspection of customer's DSG system reveals either a hazardous condition or lack of proper maintenance or records; DSG system interferes with service to other customers or operation of utility system; or personnel safety is threatened.

(4) The utilities require the customer to provide, install, and maintain a protection system. Common requirements include:

   a) Faults on the utility system must be sensed and DSG equipment disconnected.

   b) Loss of utility source must be sensed and the DSG equipment disconnected.

   c) Dead circuit energization by DSG units is prohibited.

   d) Islanded operation of DSG units is prohibited.

   e) Automatic synchronizing equipment or utility supervision of manual synchronizing (for some smaller DSG sizes) is required.

TABLE 1

NEW YORK UTILITY INTERCONNECTION REQUIREMENTS

Requirement	Utility A	B	C	D	E	F	G
Utility Approval Prior to Operation	X	X	X	X	X	X	X
Utility Inspection	X	X	X	X	X	X	X
On Premise Maintenance Log	X	X	X	X		X	X
Lockable Manual Disconnect Switch	X	X	X	X	X	X	X
DSG Shall Not Energize a Dead Circuit	X	X	X	X	X	X	X
Harmonic Content Limit	X	X	X	X	X	X	X
Reactive Power Meter			X				
Protective Equipment Including:							
Main Circuit Breaker	X		X	X		X	
Power Transformers for Isolation	X		X				
Automatic Fault Detection and Shutdown Equipment		X	X	X	X	X	X
Dead Circuit Detection Equipment		X	X		X	X	
Over/Under Frequency and Voltage Relays		X	X				
Directional Over Current Relays		X					
Ground Overcurrent Relays		X		X			
Synchronizing Equipment				X		X	
Conform to the Applicable Codes Including:							
National Electric Code		X	X		X		X
National Electric Safety Code			X				
Fire Underwriters			X		X		
UL Approval						X	
DSG May Not Backfeed Power to Secondary Networks	X						

Utilities

A. Consolidated Edison Company
B. Central Hudson Gas and Electric Corporation
C. Long Island Lighting Company
D. New York State Electric and Gas Corporation
E. Niagara Mohawk Power Corporation
F. Orange and Rockland Utilities
G. Rochester Gas and Electric Company

(5) The customer must comply with various codes including: the National Electric Code, National Electric Safety Code, Fire Underwriters Code, UL approval, and applicable local codes.

The protection requirements presented in Table 1 and discussed above are adequate to accommodate today's relatively small penetration of DSG units on utility systems. However, modifications to utility systems will be required to enable the integrated monitoring and control of large numbers of DSG units. Although the anticipated communications and control equipment is not generally available at the present time, no major obstacles to its development are expected (6).

INTERCONNECTION COSTS

Installed capital costs of interconnection equipment are primarily determined by the following factors:

- Type and size of generator;
- Interconnection voltage;
- Requirement for and size of transformer;
- Engineering and installation; and
- Degree of protection required.

Generator size and interconnection voltage have the largest effect on interconnection costs. The direct effect of increased generator size is increased switchgear cost. The high and low voltage switchgear must be capable of withstanding the added fault current contributed by a larger generator. The cost of connecting at a higher distribution voltage (13.8 kV) is much greater than the cost of connecting at a lower distribution voltage (2.4 kV), unless a customer's load is great enough to already require high-voltage switchgear.

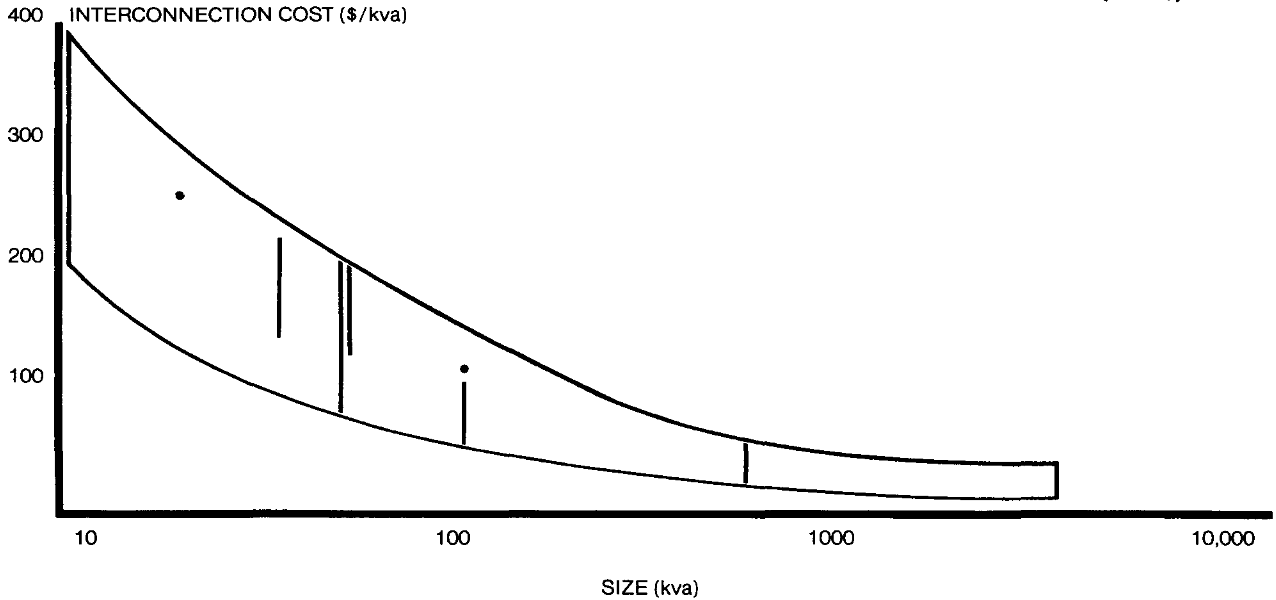
The cost of a transformer can be 30 to 50% of interconnection costs (7). For some DSG facilities, e.g., large industrial cogenerators, a transformer sized to the customer's peak load is already in place. If the capacity of the DSG is a fraction of that load, a new transformer is not required. However, for smaller DSG installations, utilities often require the installation of a dedicated transformer.

Engineering and installation costs can vary from 10% to 20% of the cost of interconnection (7), with a higher cost percentage being associated with smaller installations.

Estimates of installed interconnection equipment costs are presented in Figure 2. These estimates are derived from three sources which each set forth hypothetical DSG

FIGURE 2

INSTALLED INTERCONNECTION COSTS (1981 $)



installations as a basis for determining costs of typically required interconnection equipment (5) (8) (9). Smaller installations are assumed to be induction generators or line-commutated inverters operating single phase at 240 - 480 V. Larger installations are assumed to be synchronous generators or forced-commutated inverters operating three phase at 2.4 - 13.8 kV. Ranges in the estimates reflect varying degrees of protection requirements applied to the hypothetical installations. These cost estimates generic and are not intended to reflect specific site utility interconnection requirements.

CONCLUSION

From the information presented in Figures 1 and 2, the fraction of total DSG project costs represented by interconnection equipment is derived and presented in Figure 3. Two ranges of estimates are provided corresponding to the different levels of installed capital costs for cogeneration and hydro/wind equipment.

The first conclusion that can be drawn from Figure 3 is that interconnection costs represent a significant portion of total project costs for smaller installations, particularly those less than 100 kW. This is due to the fact that any DSG installation requires a minimum amount of protection equipment, e.g., protective relays and transformers, the costs of which are fixed and can be a large fraction of the total installation costs for small generators.

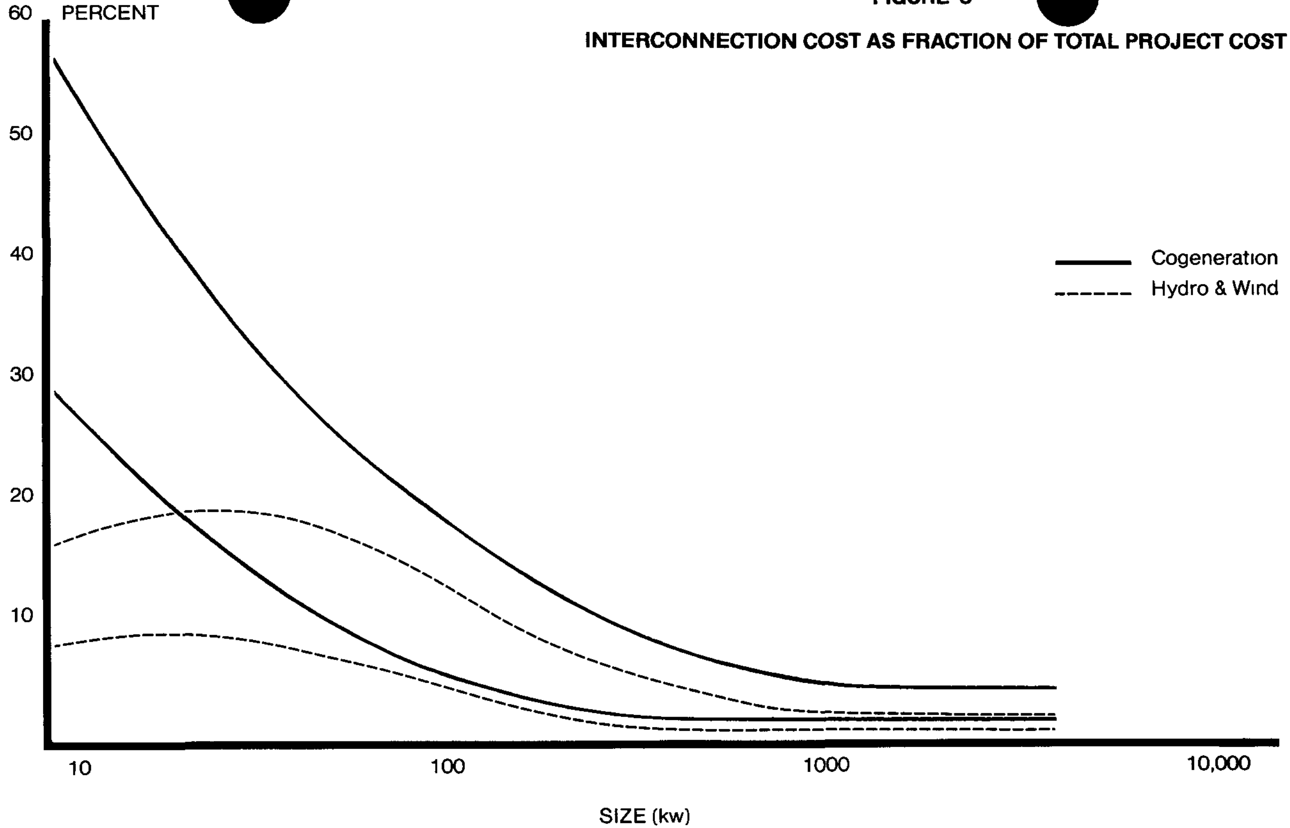
The second conclusion that can be drawn from Figure 3 is that the range in the fraction of total project costs increases for smaller facilities. This largely reflects variations in judgements, depending on the reviewer's degree of conservatism, regarding what constitutes adequate protection for a specific application.

Two factors impact on the uncertainties facing small DSG developers wishing to interconnect to utilities. First, relatively few small, utility-interconnected DSG facilities exist from which to draw hard data. Secondly, published utility interconnection requirements are imprecise and not consistently defined.

To address this problem, the New York State Energy Research and Development Authority (ERDA) is planning a project to document the actual interconnection requirements and costs of existing DSG installations in New York. Through an examination of the terms and conditions of agreements between DSG operators and New York utilities, ERDA expects to reduce some of the uncertainties regarding interconnection costs that currently face DSG developers.

FIGURE 3

INTERCONNECTION COST AS FRACTION OF TOTAL PROJECT COST



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UTILITY PERSPECTIVE OF COGENERATION INITIATIVES

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INTRODUCTION

Since the Arab oil embargo of 1973 and the public awareness of the "energy crisis" there has been extensive activity, both public and private, in energy related industries. Many energy production and conversion technologies have come into prominence. Some of these concepts are relatively new while others have been established for many years. Cogeneration is one of these established technologies, even though the term cogeneration is relatively new. This paper presents one utility's perspective on cogeneration.

DESCRIPTION OF PSE&G

Public Service Electric and Gas Co. (PSE&G) is the largest utility in the State of New Jersey. The Company's electric and gas service area is a corridor of approximately 2600 square miles running between New York City and Philadelphia. Although PSE&G serves only one-third of the geographic area in New Jersey, it provides 60% of the electric and gas energy usage in the state. PSE&G is a member of the Pennsylvania-New Jersey-Maryland Interconnection (PJM), the oldest power pool in the United States. The many transmission ties to PJM companies and other neighboring utilities allow PSE&G to exchange energy with utilities throughout the Northeast, Midwest and Southeast portions of the United States.

Table I shows the actual PSE&G electric sales, peak load and capacity for 1970, 1981 and forecasted values for 1990.

Table I
PSE&G Electric Sales
Load and Capacity

	1970	1981	1990
Residential Sales	27%	27%	27%
Commercial Sales	29%	36%	39%
Industrial Sales	44%	37%	34%
Peak Capacity(MW)	6597	9101	9994
Peak Load(MW)	5750	7034	8200

As can be seen, PSE&G's service territory is evolving from an industrial based to a service oriented economy. The Company is currently forecasting a long-term (1981-1995) growth rate of 1.8% per year for total sales to customers and 1.4% per year for planning peak loads. Table II presents PSE&G's 1981 electric generating capacity and energy mix.

Table II
1981 Capacity and Energy Mix

Capacity		Energy	
Nuclear	20%	Nuclear	25%
Coal	22%	Coal	28%
Oil & Gas Steam	27%	Oil	12%
Combustion Turbine	29%	Gas	17%
Pumped Hydro	2%	Purchases	18%

After the installation of Hope Creek No. 1, a 1067 MW nuclear unit, in late 1986, the Company does not plan to install any new generating capacity until the end of the 1990's. However, PSE&G does recognize possible development of cogeneration and small power producing facilities and has therefore included a reasonable amount of non-utility generating capacity, in appropriate, years in the Company's electric capacity forecast.

COGENERATION RELATED ACTIVITIES

Linden Generating Station - Cogeneration is not new at PSE&G. Since 1957 the Company has been cogenerating electricity and process steam at its Linden Generating Station. The Linden Station steam units have an electrical capacity of 459 MW and are capable of producing 2.5 million pounds of steam per hour. Steam produced at this plant is exchanged for fuel with

Exxon's Bayway Refinery located adjacent to the plant. This exchange agreement has benefited both companies for twenty five years. PSE&G customers receive lower cost electric energy (than could be produced at the Company's other oil burning plants) and the Refinery avoids constructing and maintaining extensive steam producing facilities.

Originally, the exchange fuel was a high viscosity (Hi-Vis) oil which is a by-product of the refining process. However, because of air quality requirements PSE&G was required to switch to No. 6 fuel oil several years ago. Exxon and PSE&G are currently investigating the installation of additional pollution control devices that will permit a return to the use of Hi-Vis oil.

Potential Non-Utility Generation - PSE&G is actively participating, with several firms, in the evaluation and potential implementation of small power producing and cogeneration facilities. Contracts have been negotiated to purchase the electrical output from a reconditioned hydroelectric station at the Great Falls in Paterson and from an Integrated Community Energy System (ICES) which will produce electric energy and provide the thermal energy for a district heating system in downtown Trenton, N.J. Additionally, PSE&G is negotiating with several governmental agencies to purchase electric energy from potential resource recovery plants.

Cogeneration Studies Done For Others - PSE&G has participated with other firms in the evaluation of cogeneration systems for the US Department of Energy (USDOE) and the Electric Power Research Institute (EPRI). PSE&G, as a subcontractor to the City of Trenton, was involved in the original Trenton ICES study [1]. Although the results of that study indicated technical feasibility, PSE&G could not economically justify ownership and operation of the facility. PSE&G in conjunction with Mathtech, Inc. conducted an EPRI sponsored study to evaluate the additional breakeven capital cost that could be justified to equip a fuel cell power plant with waste heat recovery [2]. The study focused on using this thermal energy for major heating/cooling applications in the residential, commercial and utility markets. In the utility market, thermal energy utilized for air preheating, boiler feedwater and condensate heating, space heating and auxiliary steam requirements in power plants was evaluated. PSE&G, as a team member with Gilbert Associates and Bergen County Utilities Authority, conducted a USDOE funded feasibility study which addressed the use of a 4.8 MW fuel cell in a sewage treatment plant [3]. In this evaluation the fuel for the fuel cell was provided by the sewage treatment process which produces methane gas in anaerobic digester tanks. The thermal energy produced by the fuel cell was to supply the thermal requirements of the sewage treatment plant and the electricity produced was to be fed back into the PSE&G grid. PSE&G is involved with several other firms in a USDOE sponsored study to evaluate the technical, economical, financial and institutional feasibility of a district heating system [4]. Phase I, the initial screening, was completed in 1979. Phase II, the preliminary detailed analysis is expected to be completed by mid 1983. The concept being evaluated involves the retrofit of several PSE&G existing generating units for steam extraction or waste heat recovery in order to produce hot water. The hot water would be distributed in a piping network to potential space heating customers in Jersey City, Newark and the Hackensack Meadowlands.

PSE&G'S COGENERATION POLICY

In 1981 PSE&G established a formal policy on cogeneration. The objectives of this policy can be summarized as follows:

1. To encourage energy-efficient, economical cogeneration and to participate, to the extent the corporate funds allow, in such projects in the Company's service territory that are in the best interest of PSE&G's customers and stockholders.

2. To purchase the electrical output of any cogenerator at a cost that PSE&G would avoid in producing or interchanging an equivalent amount of energy or as established by New Jersey Board of Public Utilities (NJBPU).

In addition to this formal policy, PSE&G does include non-utility generation, consisting of potential cogeneration and small power producing facilities, in the Company's electric capacity forecast where appropriate.

PSE&G COGENERATION EVALUATIONS

In the mid 1970's there were various estimates made of the cogeneration potential in New Jersey. These estimates ranged from very low amounts to upwards of 4000 MW. In investigating a selection of these claims, PSE&G found some were based on just the addition of total boiler horsepower (bhp) obtained from state insurance records. In some cases no regard was given to physical limitations, economics, or whether the boilers were used as standby capacity or even used at all. In order to get a reasonable cogenerator projection, PSE&G decided to conduct its own potential cogeneration survey and analysis [5].

Customer Survey - In 1977 PSE&G developed a list of all industrial customers estimated to have 250 boiler horsepower or more. This list consisted of approximately 220 customers. The listing was then refined to those 182 customers with 500 bhp or more. PSE&G marketing representatives contacted these 182 customers to obtain detailed information on their steam and electric demands from the people who were familiar with the plant operation. Approximately 50 percent of the 182 customers were eliminated because they had steam demands too small to be realistically considered for cogeneration. A third iteration narrowed the list to 78 customers with a demand of 44,000 pounds of steam per hour or more. Twenty-three customers had a use of 100,000 lb/h and from those, PSE&G selected 18 customers with 100,000 lb/h or more and a minimum use of 50,000 lb/h for 5000 hours or more for a detailed site specific analysis. Steam profiles were prepared for these customers to aid in the feasibility analyses.

Evaluation Methodology - For the evaluation of cogeneration PSE&G chose the combustion turbine-waste heat boiler combination over the coal or oil fired boiler-steam turbine or diesel because of environmental and cost constraints in N.J. It was assumed that the cogeneration facility would be utility owned and thermally dispatched. The demand for thermal energy was used to determine the capacity and output of each cogeneration facility. Since each system would be connected to the utility electrical grid, the electric energy produced would be fed into the grid and utilized to supply other utility customers. This approach promotes an annual fuel utilization efficiency which closely approaches the peak operating efficiency.

Economic Analysis - The economic analysis was based on a total system approach in which the total costs to PSE&G and the customer were determined with and without the cogeneration facility. the total costs were determined using the minimum revenue requirement approach. Minimum revenue requirement is the minimum amount of money that must be obtained to cover all operating expenses including those associated with capital recovery. The major cost components were:

1. Those costs associated with the production of energy from a cogeneration facility including capital, fuel, operating and maintenance.

2. Net utility savings and credits resulting from operation of the cogeneration facility

3. The costs associated with the conventional heating (and cooling, as applicable) facilities to provide thermal output equivalent to that of the cogeneration facility, including capital, fuel, operating and maintenance.

In an analysis of a cogeneration retrofit situation where there are existing boilers, it is inappropriate to include the capital cost of these boilers in determining the total cost of the conventional system because these costs are considered sunk costs. The lack of the need for major capital investment in conventional-boiler alternatives means that it would be more difficult for a cogeneration system to compete economically with a conventional system in a retrofit situation.

<u>Study Results</u> - Results of the cogeneration evaluation, performed in 1977, indicated that there was a theoretical cogeneration potential of 430 MW among the 18 customers surveyed. However, based on the economic analysis only 12 of the customers with a total of 300 MW were marginally economic.

<u>Customer Reaction</u> - In addition to the very detailed study conducted on the 18 customers, special visits were made to several large industrial steam users to discuss the potential for cogeneration development. Key points which surfaced at these visits were:

1. If the cogeneration scheme proved economic from the customer's point of view, they would be interested.

2. Most industries would be reluctant to establish a long-term contract with anyone for a cogeneration system.

3. Reliability is essential to many customers. Most would require backup steam supplies for a cogeneration system.

4. Cogeneration would not significantly reduce customer manpower, maintenance, or plant equipment requirements.

5. The operation of existing steam plants as standby or topping to a cogeneration system could cause several problems. The most prevalent was increased boiler maintenance due to low circulation and the necessity of keeping boilers at a reduced firing rate for standby.

6. Most of the customers would incur an additional insurance expense with a cogeneration facility on their property.

Updated Evaluation - Since the 1977 cogeneration evaluation many economic parameters have changed such as fuel price projections and customer energy demand profiles. PSE&G reevaluated the original 18 potential cogeneration customers [6]. Company marketing representatives contacted these customers to obtain up to date information on their energy use patterns. Of the original potential 430 MW among 18 customers, the reevaluation indicated a potential of 230 MW among 11 customers. The reasons for the drop in potential cogeneration are:

1. Customer steam demand has dropped due to conservation such as improved insulation, repair of leaks and capture of waste heat.

2. Some customers have ceased operations due to economic conditions.

LEGISLATIVE ENCOURAGEMENT

PURPA Compliance - As a result of the national and worldwide energy crisis the United States Congress passed in 1978 several pieces of legislation known as the National Energy Act. One piece of the act that has a direct impact on cogeneration is the Public Utilities Regulatory Policies Act (PURPA) of 1978 (PL 95-617). This act requires a public utility to interconnect with a private cogenerator, wheel the energy for the cogenerator and sell energy to and/or purchase energy from the cogenerator. By this act, the Federal government determined that cogeneration is worthwhile and should be aggressively promoted [7].

In response to a Federal Energy Regulatory Commission (FERC) order requiring all states to comply with PURPA, the New Jersey Board of Public Utilities (NJBPU) has promulgated rules that PSE&G will purchase energy from cogenerating facilities of less than 1 MW capacity at 110% of the PJM Power Pool billing rate. The billing rate represents the average avoided cost to PSE&G to purchase or generate the same amount of replacement energy. For the purchase of energy from facilities equal to or greater than 1 MW PSE&G will negotiate a price that is fair and reasonable and that does not require a subsidy from other customers.

The NJBPU also requires PSE&G to pay capacity charges, when applicable, to cogenerators and small power producers over 100 kilowatts if the facility meets the PJM reliability criteria. Whether or not a cogenerator meets the PJM reliability criteria is based on the historical or anticipated availability of the generating unit as well as the projected forced outage rate and the planned maintenance schedule. The capacity charge is determined by evaluating the projected capacity requirements of PSE&G and other PJM companies. If there is a change in projected PSE&G capacity purchases or anticipated capacity sales due to inclusion of the cogeneration capacity, then that change in capacity requirement is priced at the appropriate PJM capacity rate. This rate then provides the basis for establishing the capacity credit applicable to the cogeneration facility.

<u>NJ Conservation Plan</u> - PSE&G has submitted to the NJBPU a conservation plan that was approved by the NJBPU in November, 1982. This plan contains two programs that address the cogeneration potential in PSE&G's service territory. First, PSE&G will provide for the development of a computerized cogeneration technical and economic feasibility analysis program. The purpose of the program is to supply customers, who may not have the resources to pursue a cogeneration analysis, with the services required to make a sound decision on cogeneration. Secondly, PSE&G will assemble material essential to the understanding, analysis and pursuit of a comprehensive cogeneration feasibility study. The purpose of this material is to disseminate reliable cogeneration information to all industrial and commercial customers.

<u>UTILITY OPERATING CONCERNS</u>

As described in this paper, PSE&G encourages the development of economic and energy efficient cogeneration. However, there are several aspects of cogeneration that are of concern to many utilities including PSE&G.

1. A cogeneration facility must be operated within accepted industry guidelines in order to protect the safety of all personnel. Adequate instrumentation and protective devices are required in order to first protect personnel and secondly minimize potential damage to equipment.

2. When a utility has significant amounts of cogeneration connected to its grid, there must be close coordination between the cogenerators and the utility when scheduling maintenance. Uncoordinated maintenance scheduling could expose the utility grid to unnecessary risks.

3. Although cogeneration provides an improved energy conversion efficiency over separate production of heat and electricity, there may be certain situations where cogeneration would cause increase usage of premium fuels. Cogeneration, which in the PSE&G area would generally be fueled by distillate oil, may not only displace oil-fired central station electric production but during light load periods could displace coal and even possibly nuclear generation. Our Nation's dependence on foreign oil would then be increased rather than decreased.

4. A cogeneration facility would likely be located adjacent to the point of electricity and heat energy use which is generally a built-up area. Central power stations would be located possibly in a remote area with tall stacks (as opposed to low level exhaust from the cogeneration facility). While there might be less emissions injected into the total atmosphere with cogeneration, the central station emissions would be dispersed as compared with the local injection of emissions from the cogeneration facilities.

5. Another concern of cogeneration is the possible loss of tax revenues. If energy is produced by a utility, the revenue derived is subject to a gross receipts tax. This tax would not be attached to cogenerated energy. Similarly, the franchise tax the utility must pay as a percentage of its investment in a community is not applied to cogeneration facilities.

6. Special incentives for cogeneration such as additional investment tax credits, over and above existing investment tax credits, low cost loans and subsidies tend to place cogeneration in a more favorable competitive position than economics would dictate. If cogeneration is to significantly participate in the solution of the Country's energy problem, it must contribute on the basis of real economics not artificially induced advantages.

CONCLUSIONS

Based on the topics discussed in this paper the following conclusions can be made:

1. For cogeneration to be successful there must be a good balance of thermal and electric energy loads [8]. Large industrial customers offer the best possibilities to match energy demands for cogeneration developmemt.

2. The economic viability of cogeneration should stand on its own. There should not be artificial stimuli such as additional investment tax credits, low cost loans and subsidies. Those who gain the benefits of cogeneration, where they exist, should pay for the cost of those advantages. The burden should not fall on the shoulders of other energy users and taxpayers.

3. Many large industrial customers have either moved out of New Jersey or have modified their plant operation such that the industrial thermal requirements are decreasing. This results in a lower potential for cogeneration within the State of New Jersey.

4. Cogeneration evaluations must be done on a site specific basis in order to truly assess the potential for cogeneration development. If the analysis is done on an industrial non site specific basis, the potential for the cogeneration development may be exaggerated.

5. In order to realize the potential benefits from cogeneration a commitment from a cogenerator to remain in a given location and produce at a given output level for many years is required. Many industries in New Jersey, especially older industries in urban areas, are unwilling to make such a commitment.

6. It appears that several cogeneration and small power producing projects may come to fruition in New Jersey, particularly electric production from resource recovery facilities. Recognizing this potential, PSE&G includes appropriate amounts of non-utility generating capacity in the Company's electric capacity forecast.

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OBTAINING PEAK EFFICIENCY in INDUSTRIAL/COMMERCIAL BOILERS

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A. INTRODUCTION

In this era of uncertain fuel prices, the cost of energy has the attention of both engineering and financial managers. Energy saving devices get the most attention, sometimes with bedazzling claims for saving money.

Saving money is often -- but not always -- a balance between investment of capital and decreasing some portion of day-in-and-day-out operating expenses.

Protective devices must frequently be included in a steam system before an energy saving device can reasonably be added. But when a capital expenditure is necessary to buy a device which protects the life of, or insures the proper functioning of, other equipment in the system, then the payback approach lacks clarity.

This paper will start with a steam system of the commercial or industrial size and identify the heat losses in it. Then various devices will be added to the system and the nature and payback potential of each device will be explored.

Commercial and industrial boiler installations are most often fueled by gas or oil. The boilers are usually packaged boilers, that is boilers which include a burner and burner controls all mounted, piped and wired by the boiler manufacturer. So, in this discussion, the term "boilers" will refer to packaged gas or oil fired boilers.

B. BOILER EFFICIENCY

The first place to look for efficiency in a steam system is in the boiler. But it's not the only feature for which boiler manufacturers design. The choice of which boiler to use doesn't always start with efficiency.

Three types of steel boilers are used in small to medium Industrial/Commercial steam systems: firetube, large watertube, and small (or commercial) watertubes:

a. Firetube boilers, as a class, probably generate the greatest amount of steam in commercial or industrial installations. A firetube is the most efficient of the types of steel boilers. Firetube boilers burning gas or oil have boiler efficiencies between about 79% and 88%. Sizes through 800 HP (26,780#/hr. of steam) are commonly used, though firetube boilers are commercially available thru 1000 HP (34,500#/hr. of steam).

b. Watertube boilers are also used in installations of the size we are discussing. Industrial watertube boilers are commerially available from about 10,000#/hr (300 HP) and up, so the smaller sizes of watertube boilers overlap the larger sizes of firetube boilers. In this overlapping area, the watertube boilers have higher prices and lower efficiencies than firetube boilers. The efficiency differential is in the range of 5%.

Watertube boilers have two outstanding features which may dictate their use in these overlapping sizes. First, they can be made with much higher design pressures: in these sizes, firetube boilers are limited to about 300 psi while watertubes can readily be built for 1000 psi. Second, watertube boilers are capable of following rapidly changing loads better than firetubes. These virtues are offset by the need, in a watertube boiler, for increased sophistication of feedwater treatment and feedwater control.

Both firetube and watertube boilers require roughly the same amount of space in a boiler room.

For larger steam systems, the initial cost disadvantage of a watertube boiler could be reversed: 2 watertube boilers would probably be less expensive than 3 or 4 of the largest firetube boilers.

c. Commercial watertube boilers overlap the lower end of the firetube size range up to about 200 HP (6,900#/hr of steam). They are designed for lower initial cost and occupy significantly less space than a firetube boiler. They are also about 5% less efficient than a firetube boiler.

Much of the sensitivity of the larger watertube boilers to feedwater quality and control is found in commercial watertube boilers.

The best beginning for an efficient steam system is the choice of an efficient boiler. That's why firetube boilers are typically used in commercial or small industrial steam systems.

In any type of boiler, efficiency will vary with fu[illegible] with firing rate, and with operating pressure. It is be- coming increasingly common for boiler manufacturers to guarantee efficiency on new boilers, so a fairly precise efficiency is known once the type of boiler is selected.

The term "boiler efficiency" is a precisely defined term, measured in accordance with a uniform method (ASME PTC-4.1). Boiler efficiency, simply put, is output heat divided by input heat. But boiler efficiency is a term like EPA mileage: to be able to use the data you must understand the definition of the term.

Let us consider boiler efficiency in the simple steam system shown in Figure B. This system consists of a boiler; two loads, one that returns condensate and one that wastes condensate; a feedwater receiver; and a feedwater pump.

The envelope inside which boiler efficiency is measured is the shell of the boiler. All losses beyond that envelope are not included in the value of the boiler efficiency.

C. THE SYSTEM

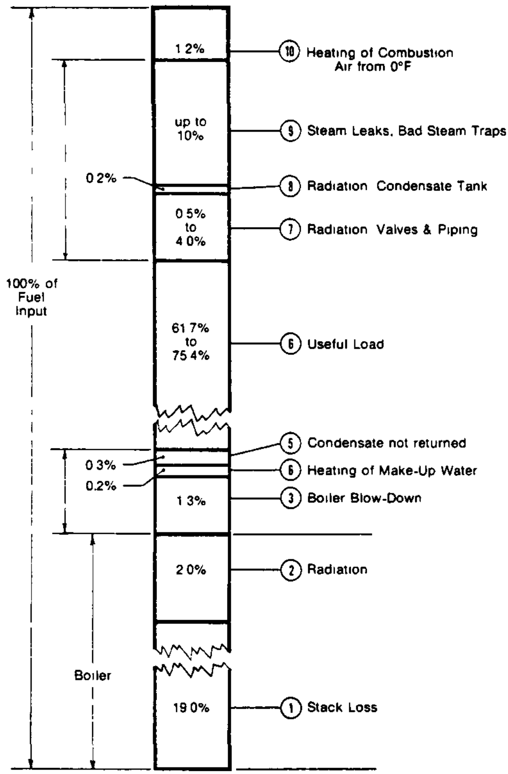
Though boiler efficiency is a major factor, it is only one factors that affects efficiency of a steam system. A complete picture of all the factors can be seen by enlarging the boiler efficiency envelope to include the entire steam system. "System efficiency" can be calculated -- or estimated -- using the heating value of the fuel as input and the heat used in the steam load as the output.

Use of the system envelope permits recognition of all heat losses and how much each loss is. It also permits an evaluation of which losses are significant enough to warrant buying a device to reduce a specific heat loss.

Using the system envelope, the losses in a steam sy[illegible] could be represented by the Btu Bar shown as Figure A. [illegible] Btu Bar is one of the effective ways of showing the results of a heat balance.

All the losses within the system envelope can be shown on the Btu Bar. Boiler efficiency itself results from only two losses: item 1, stack loss; and item 2, radiation. The losses depicted are for a gas fired boiler and amount to 21%. The remaining 79% of the energy in the fuel goes to other losses and to productive use in the load. In the system depicted here, only 61% to 75% of the heat in the fuel is usefully consumed in the load.

While the values on this Btu Bar may be "typical values", the only use I suggest you make of these or any other typical values is ballparking, i.e., getting an idea of the order of magnitude of the various losses. Do not base any buying decision on typical values; if you are evaluating a system, determine the correct figures for that system and base your decisions on them.



Btu BAR, GAS FIRED BOILER

Figure A

Knowing your annual fuel cost will also assist you in evaluating losses in your system. As an example, a 300 HP boiler burning natural gas that costs about $5.50/million Btu's will have an annual fuel cost of $150,000 to $300,000/year. Any changes made in the steam system will, therefore, save from $1500 to $3000 for each 1% improvement in system efficiency.

It takes only a glance to see where improvements should begin in this this system: at steam leaks, item 9; especially steam traps. I hope the 10% loss shown is too great to be representative of your steam system, but it might be an item to check before spending money to buy devices. This is a way to save operating costs with little or no capital expenditure.

D. COMPLETING THE STEAM SYSTEM

Devices that can be added to a steam system to make it more efficient affect principally two losses shown on the Btu Bar: stack loss, item 1, and boiler blow-down, item 3.

The amount of each of these losses vary from steam system to steam system. Partial recovery of these two heat losses is the principal justification for efficiency improvement devices added to the steam system.

Returning once more to Figure B, let's expand the system and examine the benefits given by each added device.

D1. Water Softener

The system shown in Figure B lacks a fundamental device: a water softener. In order to maintain the efficiency built into the boiler, the heating surfaces must be kept clean. Scale from hard water that forms on the water side of a boiler's heating surface is a thermal insulator. Scale prevents heat from flowing through the metal of the boiler, to the water and causes the flue gas to leave the boiler at a higher temperature. This increases stack losses and reduces both boiler and system efficiency. That's why the water going into any steam boiler should contain no hardness. Unless you have an unusual water source, all make-up water to a steam system should be softened.

The effects of scale in boiler water are cumulative so they should be prevented, either by a water softener or by adding chemicals (sulphites) to the water. But chemicals are expensive operating costs and increase the rate of blowdown. Consequently a water softener, shown as item 2 on Figure C, is usually the best approach.

A water softener is a protective device, so payback on its initial cost is difficult to evaluate. The price of a water softener can vary between $4,000 and $10,000, depending upon the volume of make-up and its hardness.

D2. Chemical Feed System:

In the basic steam system shown, water treatment should be provided for scale, for oxygen, and for any other conditions recommended by your water treatment consultant. A water softener takes care of the scale, but the remainder of the chemical treatment is equally important to protect your investment and prolong the life of your boiler and steam system.

Regularity of chemical treatment is essential. A chemical feed system, item 3 on Figure C, will permit your operators to consistently add the recommended chemicals. This device meters a pre-set volume of chemicals and can be synchronized with the flow of make-up or of feed water.

The payback on a Chemical Feed System is also difficult to calculate. Their relatively low cost -- $1000 or less --

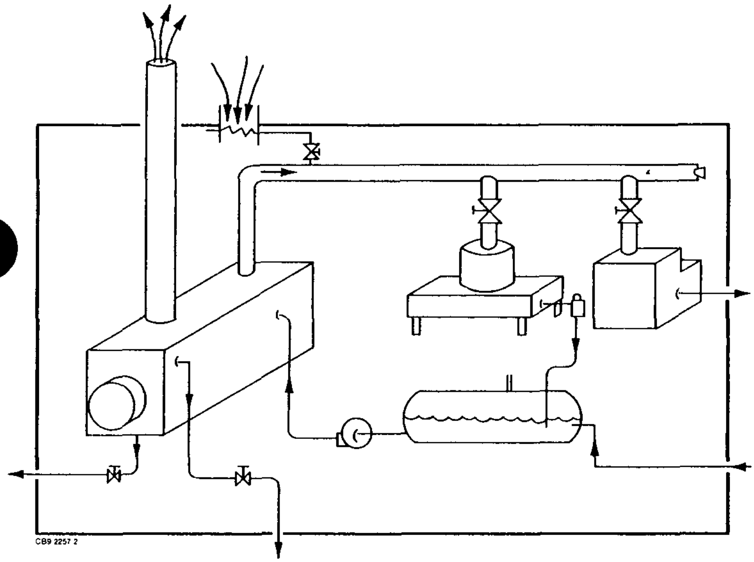
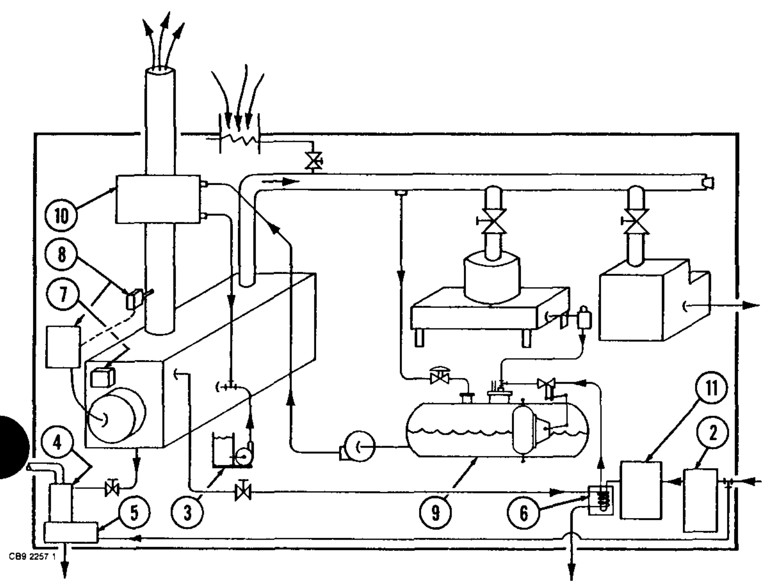


Figure B: Simple Steam Boiler System



② Water Softener
③ Chemical Feed System
④ Bottom Blowdown Separator
⑤ Bottom Blowdown Aftercooler
⑥ Surface Blowdown Heat Recovery
⑦ Annunciator
⑧ O_2 Trim
⑨ Deaerating Feedwater Heater
⑩ Economizer
⑪ Dealkalizer or Reverse Osmosis

Figure C: Complete Steam Boiler System

is usually a small investment in protecting your entire steam system.

D3. Bottom Blowdown Separator:
One of the losses within the system envelope is bottom blowdown. Bottom blowdown is done intermittently, usually manually. There is sensible heat in the blow-down water, but unfortunatly there is also a high concentration of precipitated impurities.

Since the blow-down water is above the saturation temperature at atmospheric pressure, some of it flashes into steam when it enters the Blowdown Separator, item 4 on Figure C. Steam is vented from the top and the liquid is drained from the bottom of the Blowdown Separator. The intermittent nature of bottom blow-down will, in most cases, preclude the recovery of the blow-down heat, but the steam could be piped to a low pressure user or could be condensed.

D4. Bottom Blowdown Aftercooler:
The greater amount of heat in bottom blow-down is in the water. But heat recovery from this water is difficult because of the probability of fouling the heat transfer surfaces with the high content of precipitated solids. So heat is seldom reclaimed from bottom blowdown, today. Instead, raw, untreated water is often added to the blowdown to cool it to the temperature that is safe -- or is mandated -- for draining it into a sewer. The aftercooler is item 6 on Figure C.

D5. Surface Blowdown Heat Recovery:
Surface blow-down is water removed from the boiler to reduce the concentration of dissolved impurities. It is a good source of recoverable heat.

Before consideration can be given to any recovery of otherwise wasted heat, the use and timing of the recovered heat must be considered. If the heat cannot be used at the time and rate at which it is available, it must be stored until the time it can be used. Storage systems are often expensive, so the most cost effective waste heat recovery is that which avoids storage by using the heat at the time it is available. And that's the case with a surface blow-down heat recovery system.

Returned condensate is quite pure whereas make-up water added to a steam system usually contains impurities. These impurities concentrate in the boiler. The concentration must then be reduced by using surface blow-down. Make-up and blow-down are, therefore, cause and effect.

A heat exchanger in the make-up line, item 6 in Figure C, complies with the use requirement of effective heat recovery. However, the effectiveness of Blowdown Heat Recovery could be further improved by improving the timing. One type of blow-down heat recovery system improves the timing by thermostatically sensing the flow of make-up water and causing blow-down only when make-up is flowing. Such devices will recover upward of 90% of the heat in the blow-down and cost between $1,200 and $12,000. Payback of a Surface Blowdown Heat Recovery system is usually relatively fast but depends upon the quality and volume of the make-up water.

D6. Annuciator:

Automatic Boilers are meant to have an operator. But that operator need not be in constantly attending the boiler. As a boiler system gets more efficient it often gets more complex, and the quality of operator becomes more important. An annunciator, item 7 on Figure C, can improve operation by providing a constant watch over the most vital boiler functions.

Usually, annuciators require a duplicate set of electrical contracts for all functions annunciated. Recently, solid state annunciators have appeared which can be wired to each side of existing trouble switches -- like Low Gas Pressure, High Steam Pressure, or Low Water Level -- and electronically sense whether the switch is open or closed. This simplifies annunciator wiring and makes installation on existing boilers quite inexpensive. The price of a 12 point solid state annunciaor is usually well below $1,000. Installation is simple because the wiring is 24 volt AC.

D7. O_2 Trim:

The heat lost out of the stack is a major loss in any fired boiler. One way to reduce that loss is by more closely approaching stoichiometric combustion. Positioning controls are used on the vast majority of small to medium sized boilers. Well-adjusted positioning controls are set for about 10% excess air on gas burners, and 15% for oil burners. Lower levels of excess air are attainable if the controls are frequently adjusted by a skilled operator, or by using more complex combustion controls.

The most promising and cost effective type of combustion control improvement is Oxygen Trim, shown as item 8 on Figure C. An O_2 Trim system senses the Oxygen in the flue gas leaving the boiler and trims the volume of fuel or of air to maintain the pre-set O_2 reading in the flue gas. The combustion control itself is not changed from the positioning type: the O_2 Trim system makes only trimming adjustments. The better O_2 Trim systems are fail-safe, i.e., upon a failure of any Trim component, the trim system is deactiviated and the controls revert to simple position controls.

The price of an O_2 Trim system is between $5,000 and $10,000 plus a day or two of installation time. Cost justification of an O_2 Trim system is nebulous since the device provides no improvement over what a good operator could provide. The advantage of the O_2 Trim system is that it maintains optimum adjustment regardless of variations in barometric pressure or ambient temperature, and it makes these adjustments continously.

D8. <u>Deaerating Feedwater Heater</u>:
Oxygen that is dissolved in the feedwater going into a boiler will corrode the metal of the boiler. Another measure that is taken primarily to protect the investment in the entire steam system is to remove the oxygen from the feed water by replacing the vented feedwater tank with a Deaerating Feedwater Heater, item 9 on Figure C. Actually the term "Deaerating Feedwater Heater" is a redundancy since oxygen removal always involves heating the feedwater. A deaerator affords two advantages to the boiler: it removes the oxygen, and it pre-heats the feedwater.

The Deaerator is usually heated with steam. The energy in the steam is merely moved from one place in the system envelope to another, so the only losses are those that result from radiation and leakage, and from venting the air out of the Deaerator. The venting process releases steam as well as air. The steam lost is small.

There is a cost payback from adding a Deaerator; the costs of chemicals added to scavenge oxygen will be reduced sharply. But since a Deaerator for a 300 HP boiler costs about $10,000, there is little payback justification. The deaerator is primarily a protective device. The presence of a Deaerator is, however, a prerequisite for installation of another device which could show an attractive payback.

D9. <u>Economizer</u>
The major heat loss from the boiler is the stack loss. One way to increase system efficiency would be to recover some portion of the heat lost out of the stack and add it to the feedwater. This recovery is possible if certain conditions pre-exist in a steam system.

An economizer is simply a heat exchanger which transfers heat from the exhaust gas into the feedwater; it is shown as item 10 on Figure C. The cost of an economizer for boilers of the size being discussed is $5,000 to $10,000. The economizer can improve overall efficiency by about 3% to 5% for a gas fired boiler when the steam operating pressure is between 125 and 175 psi.

Unfortunately these qualifications -- and more -- are necessary to describe the benefits of an economizer. A prerequisite for today's economizer is that the feedwater flowing through it be free of oxygen. If it isn't, the tubes of the economizer will corrode and any fuel cost saving will be eaten up by tube replacement costs. In practice, a steam system needs a Deaerator to provide the oxygen-free water to an economizer.

Economizer performance depends upon the temperature difference between the flue gas and the feedwater. Since the feedwater will come from a Deaerator, that temperature is relatively constant: about 220° F. The temperature of the flue gas depends upon the operating pressure of the boiler. In practice, the payback of an economizer is not attractive if the boiler operates below 100 psi or if the boiler is smaller than 100 HP. These are ballpark figures based on today's prices of oil and natural gas.

Another factor enters into the consideration of whether to use an economizer: sulfur in the fuel being burned. If sulfur is present, the feedwater temperature must be increased to prevent cooling the flue gasses below the sulfur dew point and forestalling sulfur corrosion from attacking the outside of the tubes. But this also reduces the temperature differential across the economizer and its payback.

D10. Dealkalizer or Reverse Osmosis:

If a steam system operates with a significant amount of make-up and/or if the water used has a significant amount of impurities -- like alkalinity, TDS, or silica -- then consideration should be given to pre-treating the make-up water. Pre-treatment, i.e., treatment before it enters the system, is afforded by adding a dealkalizer or a reverse osmosis unit, shown as item 11 on Figure C, to the discharge of the water softener.

The price of the dealkalizer or reverse osmosis unit depends upon flow rate and water quality, so prices can vary widely. The payback -- often attractive -- accrues from two factors: sharply less use of water treatment chemicals and significantly less blow-down. Both of these factors are cost savings, but only one -- blow-down reduction -- is an efficiency improvement.

Consider the investment effect of pre-treatment. As pre-treatment is added, blow-down is sharply reduced, and the payback for a blow-down heat recovery device is also sharply reduced. Planning the eventual scope of your steam system should include awareness of this.

E. FUTURE STEAM SYSTEMS

Figure C shows a reasonably complete steam system appropriate for today's fuel price. If fuel prices were to increase by a factor of 2 or 3 -- and if this increase were more than the inflation for other goods -- then the schematic of the steam system would probably look pretty much the same, but several components may change radically.

E1. Pre-Treatment of Feed Water:

In the past, when fuel was really cheap, few commercial or industrial steam systems used heat recovery devices on blow-down lines. These devices are now becoming more common because of today's fuel prices. As fuel prices increase, the emphasis will probably change from recovering blow-down heat to preventing blow-down by pre-treatment of make-up. The future probablity of a faster payback of feedwater pre-treatment should overcome today's reluctance of many managers to train their boiler room staff to deal with the chemical aspects of pre-treatment devices. Consequently dealkalizers, demineralizers and reverse osmosis units may become much more common.

E2. Condensing Economizers:

At today's fuel prices, any corrosion of economizer tubes will cause a tube replacement cost greater than the savings from the recovered heat. If, at today's fuel prices, the materials of the economizer were improved to eliminate corrosion, the higher cost would make today's payback time unacceptably long. But if fuel prices were several times today's fuel prices, the use of more exotic and more expensive materials would be justified.

Most of today's economizers extract only the sensible heat from flue gas. But all boiler flue gas also contains moiture, the end product of the combustion process. The latent heat in that moisture can be reclaimed by condensing the flue gasses. Today, condensing economizers are rare, but higher fuel costs could make condensing economizers almost routine, especially with boilers that burn no-sulfur fuels like natural gas and most distillate oils.

By designing the economizer to reduce the outlet flue gas temperature to 120°, stack losses could be reduced an additional 3% to 4%. Such a reduction of stack gas temperature would require a source of water colder than the final stack gas temperature. Only make-up water could be expected to be that cold, so the future condensing economizer would probably be a two section economizer. The first section would be exactly like the economizer shown in Figure C. The second section would receive the flue gas discharge from the first section, and the make-up water would be piped through it.

Future condensing economizers may not be for all steam systems, but with the incentive of higher fuel prices, condensing economizers may well become commonplace.

E. CONCLUSION

As we have seen, capital expenditures in connection with a steam system do not always show a clear payback. Where a payback does result, the amount of the payback will vary from steam system to steam system. The payback of heat recovery devices will increase as fuel prices rise, but the steam system itself may undergo changes which emphasize prevention of heat losses rather than their recovery. It may be well to consider whether these changes will affect the long range planning for your steam system.

METHODS TO IMPROVE THE OPERATING COEFFICIENT OF PERFORMANCE OF HEAT PUMP WATER HEATERS

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INTRODUCTION

Dedicated heat pump water heaters (HPWHs) are currently being marketed by a number of companies. These units are of two basic designs with the individual companies each offering unique design features as well. One basic design is the integral unit with the fan, evaporator and compressor located on top of a storage tank and the condenser immersed in or surrounding the tank. The second design is the add-on where the heat pump is remote from the storage tank. In the add-on units, water is circulated between the heat pump and the storage through flexible tubing.

Design variations among add-on HPWHs are discernable in the areas of controls, storage tank interfacing, and recovery rate. Table 1 summarizes design and Energy Factor data for various HPWHs. Table 1 was derived from sales literature and phone conversations with HPWH marketers. Variations in the Energy Factor rating among add-on units (as published in reference 1) will result in variations in expected energy savings of 47 to 62% per year.

Variations in add-on HPWH compressor efficiency, heat exchanger performance and resulting system (refrigerant) operating conditions are expected to exist but are not discernable from the manufacturers' literature. In an early study by Hustrulid and Cloud (2) of HPWH designs, the influence of various evaporating temperatures upon expected system COP was discussed. The lower the evaporator temperature (and/or the higher the condenser temperature) the lower the COP. This early study indicated that the highest COP was likely for a HPWH with a completely submerged (in the storage tank) refrigeration system. Units having on submerged condensers and those with remote counterflow condensers provide lower COPs in the order given. The higher Energy Factors for integral HPWHs given by reference 1 indicates these early design suggestions and results are being validated by the performance of commercial units.

While it is probably unlikely that the best add-on HPWHs will be capable of achieving the performance levels of the best integral units, there are several aspects of add-on HPWH operation which, if understood and accounted for by manufacturers, could contribute to generally higher Energy Factors for the units. In addition, field tests of HPWHs have generally not included in the data collected information concerning certain key factors which we believe will influence performance. Finally, the Energy Factor values derived from the NBS/GAMA test (3, 4) are not necessarily indicative of expected field performance of HPWHs operated with water usage rates or storage tank sizes different than those used in the test procedures. The variation in HPWH performance will be greater than the variation in conventional water heater performance under similarly varying loading.

STORAGE TANKS AND ADD-ON HPWHs

All add-on HPWHs must be connected to a storage tank due to their low recovery rates. As noted in Table 1, there are four different locations on the storage tank to which water is returned from various HPWHs. These locations vary from the same location used to remove water (the drain valve location) to the hot water exit pipe or the pressure relief valve. All add-on heat pump water heaters remove water at the storage tank drain valve location in an attempt to utilize colder inlet water available due to ta stratification. NBS/GAMA tests (3, 4) specify the use o nominal 50-gallon storage tank (electric water heater).

Laboratory testing at Cornell of one model of add-on HPWH indicated that the location used to return water to the tank may influence the HPWH operating COP. The HPWH tested returned water from the HPWH to the cold water inlet location on the storage tank. Return of water to the tank cold water inlet resulted in two adverse affects on HPWH performance.

TABLE 1. Manufacturers of HPWH

	Fedders	Duotherm	Temcor	E-Tech	Morflo	Carrier	Sears	Rheem
Controls								
Water Flow Control Valve	-	-	-	x	-	x	-	-
Pump Timer	(15 min) x	(10 min) x	(1) -	(1) -	(15 min) x		(?) x	Continuous Flow
Variable Water Temp. Setting	x	-	x	(?) x	-	x	-	-
Refrigerant								
R-12	x	x	x	?	x	x	?	x
R-22	-	-	-	?	-	-	?	-
Recovery Rate (GPH)	18	15.5	13.5	18	16	12	n.a.	n.a.
Water Inlet								
Tank Drain Point	x	x	x(2)	x	x	x	x	x
Water Return								
Cold Water Inlet	-	x	-	-	x	-	x	-
Hot Water Exit	-	-	-	x	-	x	-	-
Pressure Relief Valve (side of tank)	x	-	-	or x	-	or x	-	-
Tank Drain Point	-	-	x(2)	-	-	-	-	x
GAMA Energy Factor Rating	N.R.	2.0	1.9	2.5	2.0	2.0	2.0	2.5

(1) Operation Time Thermostatically Controlled
(2) Patented Connector

The first adverse effect was a result of induced flow of water through the HPWH. As cold water entered the tank through the cold water line and dip tube, flow of water out of the drain valve location, through the HPWH and into the cold water inlet was induced. This resulted in activation of the HPWH by the thermostat which senses the HPWH inlet water temperature. In this way the HPWH was activated with a water usage of little more than 1 or 2 gallons since the cold inlet water to the tank tends to also become the inlet water to the HPWH. Under circumstances of low water usage it is possible the mixing of the inlet water in the storage tank, which would normally occur under conditions of such usage, would not result in water temperatures low enough to activate the HPWH. The result of the induced flow was to sustain the average storage tank temperature at levels closer to the HPWH cut-out temperature thereby increasing the heat loss rate from the tank and from the HPWH during its operation.

The second adverse effect of the use of the cold water inlet as a return location concerns the resulting reduction in tank stratification. Once the HPWH circulating pump was activated, approximately 2.5 gallons per minute of water were removed from the tank bottom and injected into the cold water inlet. As a result, with an expected drawoff rate of 2 to 5 gallons per minute, the flow rate into the tank through the cold water inlet pipe would be 4.5 to 7.5 gallons per minute. This high flow rate is believed to greatly increase tank mixing, causing a reduction in tank stratification and higher temperature water entering the HPWH. Operation of the HPWH circulating pump during tank draw probably should be avoided to maximize stratification and COP.

The NBS/GAMA test procedure for add-on HPWHs (3, 4) utilizes the cold-start (recovery) COP of the unit to derive an expected daily COP which is called the Energy Factor. NBS has reported (4) a variation in the COP versus the initial inlet (Tii) water temperature of one model of add-on HPWH which can be approximated by the equation given below (the NBS data was presented in Figure form):

$$COP_R = 3.25 - .025\ (Tii) \qquad (1)$$

Ambient air temperature was 27°C.

Since the degree of tank stratification will effect the average water inlet temperature to the HPWH, tank stratification is potentially important. Each 10°C increase in inlet water temperature will change the expected COP of this particular HPWH by 0.25 units. Since the HPWH tested by NBS was equipped with a flow control valve which delivered water at 46.1°C (115°F), the COP value represented by the above equation is essentially a overall COP rather than an instantaneous value.

Tests at Cornell with an add-on HPWH without a flow control valve result in the following expression for the instantaneous COP as a function of inlet water temperature.

$$COP_I = 4.22 - .032\ (Ti) \qquad (2)$$

Ambient air temperature was 25°C.

The above expression for COP cannot be directly compared to that in equation 1 since equation 1 is the overall COP for delivery of 46.1°C water. Equation 3 presents the COP at the unit tested at Cornell assuming 46.1°C water is eventually produced by the unit (via numerous passes of the water through the unit rather than the single pass of the NBS test unit).

$$COP_R = 3.41 - 0.17\ T(ii) \qquad (3)$$

Equations 1-3 illustrate the dependence of HPWH recovery COP on the initial inlet water temperature from the storage tank. This sensitivity is an order of magnitude greater than that found in field studies (6).

Laboratory testing at Cornell has demonstrated that the size tank to which the add-on HPWH is connected can affect the measured COP. Table 2 contains a summary of the performance data for the add-on HPWH tested with two different size storage tanks. While cold-start (recovery) COPs were greater for the larger tank, the COPs measured during the lower draw conditions were generally greater for the smaller tank. The primary reason for the greater COPs under draw conditions with the smaller tank is believed to be the colder initial inlet water temperature in the smaller tank as shown in Table 3. When one considers that the initial tank temperature was 60°C and the inlet water 19°C, the data of Table 3 indicates a high degree of mixing of the inlet water. Both storage tanks were equipped with dip tubes on the cold water inlet. Data from field studies (6,7) indicates relatively little effect on COP due to the supply water temperatures. This is probably due to the mixing effect noted above effectively masking the influence of the supply water temperature variations.

If the laboratory tests shown in Table 2 are indicative of expected field performance of this particular model HPWH under draw conditions, the data indicates the smaller the storage tank the higher will be the operational COP. (Actually, more correctly, the greater the daily tank turnover rate the higher the COP.) Operation of add-on HPWHs with the smallest possible storage tank would appear to increase the operating COP of these units when in actual use. In addition to the improvement in COP due to the colder HPWH inlet water temperature, the use of a smaller tank will result in lower standby losses. HPWH operation to replace standby losses results in operation at a

TABLE 2

Summary -- Lab Testing of HPWH

Test		COP
Cold-start	(300 ℓ tank)	2.6
	(110 ℓ tank)	2.4
18.9 liter (5 gallon) draw off		
	(300 ℓ tank)	1.8
	(110 ℓ tank)	2.0
37.9 liter (10 gallon) draw off		
	(300 ℓ tank)	1.9
	(110 ℓ tank)	2.0
56.8 liter (15 gallon) draw off		
	(303 ℓ tank)	2.2
	(114 ℓ tank)	2.2

Ambient for all runs approximately 25°C.
Supply cold water approximately 19°C.

$$COP = \frac{\text{Energy Added to Water}}{\text{Energy into HPWH}} = \frac{\text{BTU's measured by BTU meter}}{\text{kWh x 3413}}$$

TABLE 3

Initial Inlet Water Temperatures
Following Completion of Draw

Test		Tii to HPWH
Cold-start	(300 ℓ tank)	19 °C
	(110 ℓ tank)	19 °C
5 gallon draw off		
	(300 ℓ tank)	51 °C
	(110 ℓ tank)	46 °C
10 gallon draw off		
	(300 ℓ tank)	46 °C
	(110 ℓ tank)	44 °C
15 gallon draw off		
	(300 ℓ tank)	44 °C
	(110 ℓ tank)	39 °C

Ambient for all runs approximately 25°C.
Supply cold water approximately 19°C.

particularly poor COP since the inlet water temperature is generally high (typically above 45°C).

BATCH MODE HPWH OPERATION

The laboratory data of Table 2 indicate that the expected COP of the HPWH tested will increase as the load increases since the cold water inlet temperature to the HPWH decreases -- the maximum COP being the value measured for the cold start operation. This data indicates that batch mode operation of an add-on HPWH may result in a higher COP than would result from on-demand operation.

Batch mode water heating is currently utilized in many parts of the U.S. where off-peak electric rates exist. Water heater capacities of 300 to 450 liters (80 to 120 gal) are used with the water heater elements energized through the off-peak side of the meter. Off-peak periods are approximately 8 hours in length.

Operation of a HPWH in a batch mode (and, possibly using an off-peak rate) would appear to offer the possibility of significant increases in unit COP due to the lower inlet temperatures. Assuming hot water usage rates of 243 liters/day (64 gal/day) resulting in water heating energy requirements (including standby losses) of 53,000 KJ/day (50,000 BTU/day) and HPWH capacities of 8,440 KJ/hr to 12,660 KJ/hr (8 to 12,000 BTU/hr), HPWH operating times of from 6.3 to as low as 4.2 hours per day would be required. Thus all the HPWH operation could be during off-peak periods. The lower off-peak electric rates and improved COPs due to batch operation would contribute to favorable economics for such operation.

SOLAR AUGMENTED HPWH OPERATION

Operation of a HPWH within the thermal envelope of a house in the northern U.S. can result in potentially poor annual COP due to the additional home heating load imposed by the HPWH. Effective annual HPWH COPs as low as 1.1 to 1.3 are estimated for houses using electric resistance heat and 1.2 to 1.6 for dwellings heated via heat pumps (both with mechanical space cooling). (5) Cost justification of the $800 to $1,400 HPWH investment becomes difficult under such conditions.

If a HPWH installed in the northern U.S. could be provided with a heat source which is not parasitic upon the dwelling heating system and is at a temperature warmer than the ambient, the cost feasibility and energy savings of a HPWH would be substantially improved. Such improvement may be possible by the installation of a HPWH within a sunspace/attached solar greenhouse.

Table 4 contains data recorded in a sunspace in Ithaca, NY during a 22-day period in the winter of 1981-82. During this period the sunspace averaged 6.3 hours per day above 10°C (50°F). During this same period the average daily high ambient temperature was 2.8°C (37°F) and the average ambient temperature -2.8°C. While some use of the sunspace for space heating would be possible, such use would generally be limited to sunspace conditions above 32°C (90°F) which was 1.1 hours per day in this sample. A substantial number of hours were available when the temperatures were higher than those expected in the usual locations for HPWH installation. Levins (6) assumed a HPWH in an unconditioned basement would experience air temperatures of 12.8°C (55°F) when ambient temperatures are below 12.8°C and that a HPWH in an unconditioned attached garage would experience temperatures 5.5°C greater than the ambient. For the 22-day period during the winter of 81-82, this would mean an expected temperature of 2.7°C in a garage. Roberts (8) indicated measured cellar temperatures of 15.5°C in June and 6.7°C in January for a NJ location. Table 4 data clearly shows substantial availability of low temperature heat suitable for operating a HPWH. This data provided the conceptual justification for an on-going evaluation of the performance of a HPWH operating within a sunspace.

Since June of 1982 a HPWH has been operating in a sunspace/greenhouse in Ithaca, NY. Initial operation of the HPWH in the sunspace resulted in relatively low COPs due to low water usage (with respect to tank size) and no attempt to control the time of operation of the HPWH to maximize COP. Increased water consumption coupled with controlling the HPWH with the upper heating element thermostat (element not connected) resulted in a significant improvement in COP. Using the tank thermostat required the HPWH to function more in a batch mode. A further control refinement attempted to operate the HPWH during periods of highest sunspace temperature. This was initially successful but later resulted in insufficient operating hours and a failure to meet the load. Since November 11, 1982 the control has been via a time clock from 1000 to 1500. Table 5 presents a summary of the HPWH performance.

The site for the HPWH/sunspace project is not an ideal location for this study. The site was graciously provided by a staff member after the funding agency declined to support the construction of a sunspace on campus. The sunspace is probably 15 years old, single glazed, faces nearly due west and has a high ratio (1.7 to 1) of glazing to floor area. In spite of these and other problems, the data gathered continues to show that solar augmentation of the HPWH has promise.

TABLE 4

Sunspace Temperature History
2/26 - 3/21/82

Temperature Range	Number of Hours Sunspace Temperature Was Within Given Temperature Range (Average Per Day)
>10°C (50°F)	151 (6.3)
>12.8°C (55°F)	116 (4.8)
>15.8°C (60°F)	94 (3.9)
>18.3°C (65°F)	75 (3.1)
>21.1°C (70°F)	63 (2.6)
>32.2°C (90°F)	27 (1.1)

TABLE 5

Sunspace Augmented HPWH Performance (1982)

Period	Water Usage ℓ/day (gal/day)	HPWH Delivered Energy KJ/ℓ (BTU/gal	HPWH COP*	Remarks
5/13 - 6/21	64 (17)	165 (591)	.60	Low water usage, standby losses large
7/8 - 10/8	151 (40)	145 (520)	1.38	Control via Tank Thermostat
10/8 - 11/15	189 (50)	66 (235)	1.90	Control via SS air temperature (HPWH on if above 25°C)
12/1 - 12/31	193 (51)	146 (524)	1.49	Time clock control (1000 to 1500)

$$*COP = \frac{\text{Energy Delivered to Home in Hot Water}}{\text{Input Electricity to HPWH}}$$

CONCLUSIONS

The are many factors which impact on the operational coefficient of performance of HPWHs. The Energy Factor values derived from the NBS/GAMA tests are not necessarily indicative of field performance. There are additional factors which impact on performance that need to be addressed. Two of these factors are discussed; temperature of inlet water to the heat exchanger (condensers) of heat pump and augmenting the temperature of the energy source.

Inlet water temperature to HPWH is believed to be influenced by the water connections between the HPWH and the storage tank, the capacity of the tank with respect to the daily water usage and the control theory employed for the HPWH unit.

Cold-start COP is the highest COP that can be achieved because Tii is lowest. System designs which promote and optimize batch mode of operation will result in the most efficient operation. Location of tank water connections with add-on HPWH, flow rates (velocity) of circulation water and draw-off, use of baffles and diffusers, size of tank with respect to usage, water flow control valves and electrical controls which restrict operation of HPWH all should be considered. HPWHs are perhaps least efficient when making up standby losses because of the high values of Tii. Small well-insulated tanks should be encouraged.

Augmenting the temperature of the energy source, in this case air, with solar energy is discussed. Using a sunspace as an energy source offers the advantage of being a non-parasitic heat source and one with elevated air temperature (elevated with respect to other non-parasitic sources). With proper installation, significant gains in operational performance and savings can be achieved by operating a HPWH in a sunspace.

GLOSSARY OF TERMS

COP_I = instantaneous coefficient of performance
COP_R = recovery COP. Would be equal to cold-start COP when tank is full of cold water.
Ti = inlet water temperature to HPWH at any time.
Tii = initial inlet water temperature to HPWH. The inlet temperature when the HPWH is energized.

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HEAT PUMP SEASONAL HEATING EFFICIENCY PREDICTION

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This paper presents the major results from a project to develop simple and accurate predictive algorithms for heat pump seasonal heating efficiency A parallel effort consisting of field tests, laboratory tests and analysis was used to prepare and verify the algorithms Additional details are available in References 1 and 2

FIELD TESTS

Field tests were conducted to measure, with integrating devices, compressor power during normal operation and during defrost operation, compressor on-off cycles, defrost cycles, indoor fan power during heat pump operation and during resistance heat only operation, resistance heat use during heat pump operation and during resistance heat only operation, hours of defrosting and hours of compressor operation The heating was accomplished either by the heat pump system or by pure resistance heat, controlled by a timer to alternate every 24 hours The primary thermostat set point control was switched at each 24 hour period so that the primary heat source (heat pump or resistance heat) was controlled to the same temperature Field measurements confirmed that the temperature control in the residence was unaffected by mode

The residential load was measured by running straight resistance heat on alternate 24 hour periods Monthly records of the total resistance heat use were obtained Concurrently obtained drybulb temperatures were used to compute the temperature distribution during resistance heat only operation An assumed linear load line was determined which best fit the measured load for all of the monthly records The regressed load lines are summarized in Table 1 The balance points computed on the basis of these load lines are also presented in Table 1 and show the equipment to be properly sized in most cases The sensitivity to errors in the load estimation was found to be small, based on simulations of test site A A summary of the field data is provided in Table 2

Table 1

SUMMARY OF TEST RESIDENCE HEAT LOSS EQUATIONS
(Based on Load and Degree Hours in Resistance Heat Mode)
Linear Equation of the Form: Loss = Rate × (T_o-T)

Test Site	Measured Load (kWh)	Heating Degree Hours	Balance Point (F)	Rate (Btu/Hr)	T_o (F)
A	8118	57800	20	488	54
B	10489	56800	30	839	55
C	13787	58400	33	784	62
D	9065	48300	28	618	59
E	8602	53900	27	554	62*
F	8816	41300	29	689	59
G	8810	29800	38	978	62*

* denotes no minimum in regression

Table 2

SUMMARY OF FIELD DATA FOR 7 RESIDENCES
(All energy use in kWhs)
(Heating Degree Hours Based on Actual Zero Load Points)
(A,B,C located in Albany, NY; D,E,F located in Harrisburg, PA)
(G located in Memphis, TN)

Test Site	Heat Pump Energy Use		Defrost		Resistance Heat Supplement	Test Hours	Heating Degree Hours
	Normal	Defrst	Cycles	Hours			
A	3015	79	1646	51 2	1721	2819	56200
B+	1131	15	238	11 8	444	1105	13800
B	1876	36	1066	33 3	3799	962	13900
C	3416	52	1900	96 8	6545	1638	58700
D	3558	111	1579	65 8	1508	1851	48100
E	3294	93	1649	64 1	1651	1876	53900
F	2030	38	1464	38 1	2030	1467	41200
G	2359	43	482	25 9	3718	1683	30900

+ first entry for site B for operation with 90 minute defrost timer, next entry for operation with 45 minute defrost timer

The weather data was found to give much less weighting to higher temperature bins than is commonly done (i e , DoE) The lack of weighting of these higher temperature bins and load lines with zero load temperatures well below the 65 F were partially responsible for the small impact of cycling on seasonal performance in these tests

CYCLING EFFECTS

The task of predicting cycling losses begins with a model for the thermostat and house A lumped parameter model which characterizes the thermostat as a constant deadband control with a fixed thermal mass in the residence has been chosen (Equation 1) The empirical parameter (C) in Equation 1 is the on period (t_0) for the heating system at zero duty cycle (F) and has typically been found to be near 5-6 minutes

$$t_o = \frac{C}{(1-F)}$$

When the thermostat model represented by Equation 1 was used, the total number of compressor cycles was vastly over predicted in almost all cases Load, frosting and defrost effects cannot reasonably explain the discrepancy illustrated by Table 3 On the assumption that the functional form of Equation 1 still held, new minimum on periods were computed which resulted in a better match to field data,these new values are also provided in Table 2 No attempt was made to match the cycles exactly for two reasons, (i) cycling rates were so low in many cases that the effect of cycling on seasonal performance was reduced to nearly insignificant amounts and (ii) cycle times in some cases had become so long that the implicit model assumption that the load is approximately constant over one cycle was clearly violated

Table 3

COMPARISON OF THE NUMBER OF FIELD DATA COMPRESSOR CYCLES TO PREDICTIONS

Test Site	Compressor Operating Hours	Compressor Cycles Reduced Field Data	Predictions Initial	Predictions Final	Adjusted Minimum On Period (minute)
A	1267	415	3550	868	25
B	1229	479	1720	541	20
C	1541	217	530	252	15
D	1318	1007	2150	1190	12
E	1305	1044	2400	1130	14
F	1182	1064	1190	1150	7
G	892	380	1500	453	18

Because of the discrepancies between field cycles and initial predicted cycles, additional measurements were made on two of the residences These measurements included use of a continuous event recorder to determine the cycling behavior, and a temperature measurement (at one site) to determine the thermostat deadband The thermostat deadband was 2 5 F ($\pm$ 0 2 F) and was independent of the operating mode The data was divided into groups representing cycles during heat pump operation and during resistance heat only operation The resistance heat groups were further divided into groups at high and low stages The data for all groups corresponds reasonably well to the functional form of Equation 1 The problem, illustrated by the data of one residence (Figure 1), is that the earlier derived constant for Equation 1 is grossly misrepresentative of the thermostat response in these structures The data in Figure 1 suggests the on period is inversely proportional to the straight heating rate, directly in accord with a constant thermal mass assumption, and diametrically opposed to a anticipator dominated thermostat model

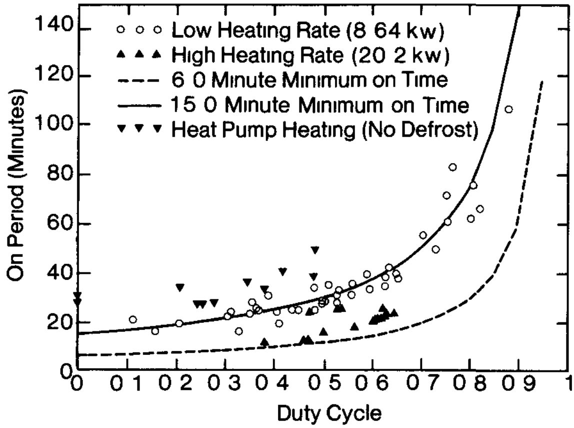

Figure 1. Field Measured Cycling Response Under Various Heating Modes

Laboratory tests were performed to evaluate the capacity (q) and power transients during startup, and the effect of off cycle period on the startup transients with no heat recovery during the off cycle The tests were performed at several ambient dry bulb temperatures and usually with a dry outdoor coil condition The capacity transients proved to be the overriding influence on part load efficiency Capacity transients from cold starts and normalized to the peak capacity (q_s) during the 15 minute startup are plotted in Figure 2 A two time constant exponential is also plotted in Figure 2 as a fit to the warm ambient capacity transients The 35 F tests were run under frosting conditions so the presence of the wet coil at startup might be expected to alter the startup transients

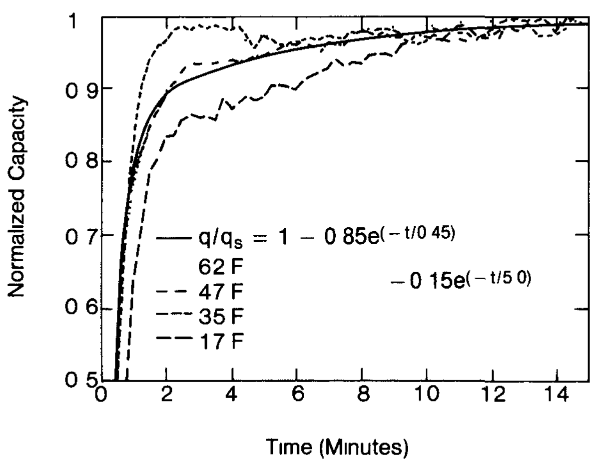

Figure 2. Normalized Capacity Startup Transients at Various Ambient Temperatures

The correlations for heat pump transients may be combined with the thermostat model to produce the commonly used part load efficiency curves. Part load efficiencies are plotted in Figure 3 against load factor for two different thermostat functions with and without the off period capacity effect. The beneficial effect of short off periods on the subsequent startup transient is found to be present, but small, only in the case of a rapidly cycling thermostat. The corresponding C_d values for the two thermostat functions are shown next to the respective curves. The startup power transients are ambient temperature dependent so Figure 3 is constructed with a load line which yields a 30 F balance point temperature. The temperature effect is slight and curves for several thermostat functions can be considered representative. The straight line, derived from the DoE cycling test, is seen to be a good approximation to the predicted part load efficiency curve if the implied DoE thermostat function is used.

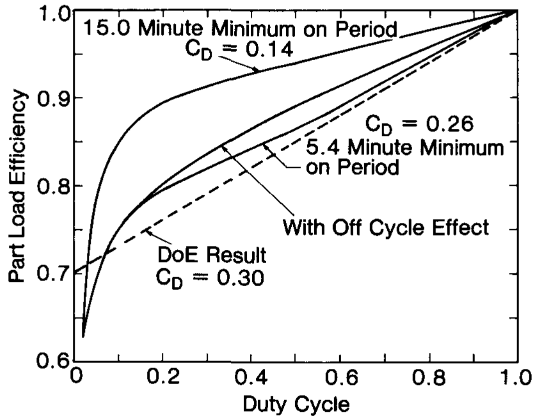

Figure 3. Part Load Efficiency Curves

FROSTING AND DEFROSTING

Laboratory frost-defrost tests were performed at ambient temperatures from 42 to 17 F and at relative humidities from 70 to 90 %. Tests were performed with a timed frost-defrost control set variously at 45 and 90 minutes. Integrated power and capacity measurements were made for each complete frost-defrost cycle. Instantaneous capacity and power were recorded for most runs. The tests were performed on two different units of the same model.

The reverse cycle defrost should ideally have constant capacity and power [illegible] both source (residence) and sink (ice) temperatures are fixed. Under an assumption of constant capacity, defrost times should be proportional to the quantity of frost plus a minimum time associated with sensible heating of the outdoor coil. The capacity ratio (ratio of instantaneous capacity to steady state capacity q_i/q_s) at defrost initiation is used as a measure of frost quantity. Defrost periods (t_d) are plotted in Figure 4 against the capacity ratio. The hoped for behavior is demonstrated, with the data reasonably well represented by a linear fit and a minimum defrost time evident. No effect of ambient temperature is evident in the data.

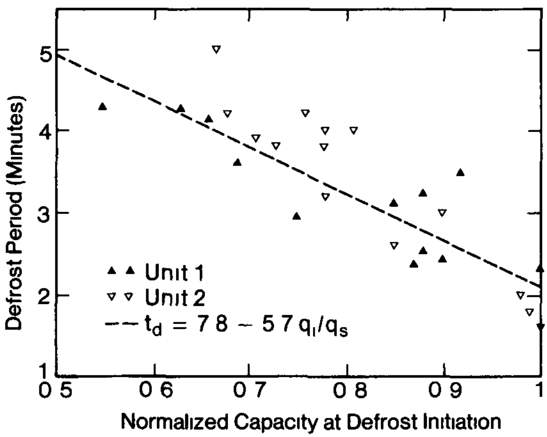

Figure 4. Defrost Time as a Function of Capacity Ratio at Defrost Initiation

Average compressor power during defrosting was measured to be 2.0 kW with little (10%) or no dependence on defrost period or ambient temperature. The power demonstrated a rapid initial transient to low power followed by a slower transient during the remainder of the defrost, only during the later parts of some defrost cycles could the power be considered to be nearly constant.

The capacity ratio was assumed to be related to the specific humidity difference and the elapsed time from peak output. The specific humidity difference is the difference between the specific humidity of ambient air and air saturated at the average coil temperature. The capacity ratio is plotted vs the product of specific humidity difference and frosting period in Figure 5. With the exception of a few points, a linear represen-

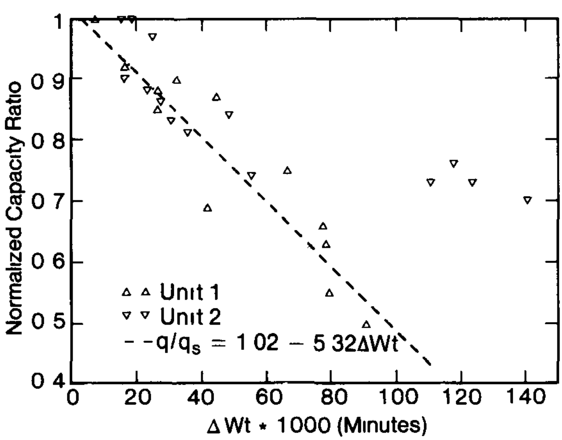

Figure 5. Capacity Ratio as a Function of Frosting Time and Specific Humidity Difference

tation works well A similar linear relationship for the integrated average power ratio data gives only a fair result, but the sensitivity of seasonal predictions was found to be insensitive to this parameter

The timed defrost strategy made prediction of the number of defrost cycles relatively easy if the load was properly characterized The number of defrosts were, on the average, predicted within 4 % The effect of frosting on the prediction of the number of defrosts was also small (less than 3 %) The prediction of the time spent in defrost is not very good

Since the defrosting period has a strong impact on the supplemental resis heat, additional field data was taken to try to resolve the discrepancy Coupled with the measurements of cycling at sites A and C were individual measurements of defrost period A tabulation of these defrost cycles for both residences showed a bimodal distribution of defrost periods, one mode slightly over one minute and another slightly over two minutes The distribution of defrost periods at site A was broken into two groups defrosts which occurred under a predicted frosting condition and those which occured under a predicted dry coil condition The resulting histogram demonstrated a marked distinction between the two modes An average of the defrosts which were predicted to occur under dry coil conditions was 1 1 minutes Most of the data from site C could not be compared to weather data, but the limited (15) number of defrosts which were compared on this basis yielded simihar results Using 1 1 minutes for dry coil defrosts, the defrosting periods are in some cases better predicted

SEASONAL PERFORMANCE PREDICTIONS

The effects discussed in the previous sections were implemented in two bin type models The models were constructed in the following order steady state ambient temperature effects with supplemental heat, cycling effects, timed defrost effects, frosting effects, demand defrost Bin calculation procedures assume each hour may be treated as a complete, periodic representation of the heat pump performance at that ambient temperature condition In the first (detailed) implementation, the bin assumption is relaxed to allow a small amount of information from the previous hour to be passed through and each bin is one degree F wide The second (bin) implementation is a strict bin type calculation with double bins, humidity bins for each five degree F temperature bin The predictions of both implementations agree very well

The steady state calculation is based on the load information and the steady state product performance given at nominal indoor airflow conditions The thermostat cycling function determines the duty cycle based on steady state capacity values, an iterative procedure follows as the capacity startup and shutdown transients are used to determine a new average capacity at an outdoor temperature The resultant duty cycle is used to establish the energy requirements based on the steady state power, a p transient model and the off cycle sump power The capacity of the heat pu represented as a constant average to all subsequent calculations at that outdoor temperature

The defrost events in the equipment occur when the set number of minutes (45 or 90 including operation during the last defrost) of compressor operation have been accumulated with the defrost temperature sensor (attached to the outdoor coil) below 26 F The only modification in the computation to the actual scheme is that the timer is reset to zero if the coil temperature is computed to be above 26 F for one hour The coil temperature is computed on the basis of laboratory data and product data which gives the steady state evaporator saturation temperature as a function of ambient drybulb temperature No account is taken of operating periods which contain thermostat as well as defrost cycling, all operation is assumed to occur with the coil temperature specified by the steady state condition even if the capacity and power are corrected for cycling

The cycling calculation is initially used to determine the fraction of time the heat pump runs, that period of time is assumed to occur in one long cycle with an average steady capacity determined by the cycling If the defrost temperature sensor is compared to be above its setpoint (26 F) then no further calculations are required If the frost sensor allows defrosting then an iterative procedure is used to determine the duty cycle which includes defrost cooling capacity, tempering heat effects and frosting effects The number of defrosts and the defrost period as well as energy requirements are then determined from the duty cycle

A demand defrost scheme was implemented in the detailed model to provide a comparison to some of the predictions in the literature The scheme assumes that a demand defrost occurs when the capacity ratio of the heat pump reaches a fixed value (0 85 in the following simulations), an equivalent hardware implementation is not specified

Table 4

FIELD PERFORMANCE PREDICTIONS AND MEASUREMENTS
(based on actual field operating periods)
DETAILED MODEL PREDICTIONS: 7 RESIDENCES

		Performance factor			
Test Site	Field Test	Steady State	Cycling only	Timed Defrost	Demand Defrost
A	1 69	1 88	1 85	1 66	1 76
B	1 44	1 74	1 73	1 58	1 64
C	1 35	1 45	1 44	1 33	1 37
D	1 75	2 00	1 95	1 74	1 81
E	1 72	2 01	1 97	1 77	1 84
F	1 69	1 85	1 81	1 62	1 68
G	1 42	1 77	1 76	1 55	1 62

Table 4 gives seasonal efficiency comparisons for the seven residences a) field test results, b) as computed using only steady state performance parameters, c) imposition of cycling on b), d) imposition of frost/timed defrost on c), e) imposition of frost/demand defrost on c) Timed defrost-frosting is predicted to result in a penalty between 11 and 14 % The demand defrost scheme is predicted to result in a penalty of 11 % or about two thirds that for timed defrost The performance predictions for the entire heating season are provided in Table 5 Full season simulations with residence D are provided in three climates in Table 6 and demonstrate a small sensitivity of cycling losses to winter severity

The final predictive comparison utilizes the DoE procedure Two calculations are performed on variations of the algorithm The first calculation uses the method exactly as specified assuming that the design load is determined by evaluating the regressed load lines at the specified design temperature These numbers are provided for 5 residences in the second column of Table 7 (two residences had 90 minute defrost timer settings and cannot be directly compared to the DoE predictions based on a 45 minute timer) The second calculation (third column) uses the cycling rate implied

Table 5

SEASONAL PERFORMANCE PREDICTIONS
DETAILED MODEL PREDICTIONS FOR FULL SEASON (1981-1982)

Test Site	Steady State	HSPF Cycling Only	Timed Defrost	Compressor Cycles	Compressor % Run Period	Defrost Cycles	Defrost Hours
A	1 78	1 76	1 58	1730	45	3290	117
B	1 60	1 59	1 47	1390	63	4400	149
C	1 61	1 60	1 48	1780	72	4680	157
D	2 05	1 99	1 79	3360	57	3280	118
E	2 09	2 04	1 84	3060	58	3280	118
F	1 99	1 92	1 74	5170	61	3510	124
G	1 95	1 92	1 71	1430	46	970	60

Table 6

SEASONAL PERFORMANCE PREDICTIONS IN THREE CLIMATES
(Residence D)

Climate	Steady State	HSPF Cycling Only	Timed Defrost	Compressor Cycles	Compressor % Run Period	Defrost Cycles	Defrost Hours
NY	1 72	1 70	1 56	3030	61	4190	142
PA	2 05	1 99	1 79	3360	57	3280	118
TN	2 19	2 11	1 90	2570	31	1502	62

Table 7

PERFORMANCE PREDICTIONS BASED ON THE DoE ALGORITHM
(Based on Actual Field Operating Periods)
(Performance Factor)

Test Site	DoE No Change	DoE Essence	Detailed Model	Field Data
A	1 72	1 68	1 66	1 69
C	1 51	1 40	1 33	1 35
D	1 91	1 81	1 74	1 75
E	1 91	1 83	1 77	1 72
F	1 85	1 70	1 62	1 69

by DoE (5 4 minute minimum on period) and the integrated performance curves based on the two (DoE) frosting tests to determine the performance in the detailed model with the actual weather and load line for each residence These last values compare very well with the measured field performance Since it was found that the DoE cycling rates resulted in an overestimation of the cycling loses (for these residences and thermostats), the results of the last calculation suggests that the effects of frosting and defrosting must be underestimated

ACKNOWLEDGEMENTS

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INDUSTRIAL HEAT PUMP: A CASE STUDY

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ABSTRACT:

Industrial processes frequently generate large quantities of hot liquid streams which provide attractive opportunities for energy conservation. A hot water stream at a large chemical plant was tapped to generate more than 30,000 lbs/hr of 60 PSIG steam for process use. Through the effective use of multistage centrifugal compressor technology and efficient flash evaporator technology heat which was considered unusable was recovered and delivered to a process steam header resulting in significant energy savings. This paper will describe the procedure used in evaluating the energy intensive source streams, hardware requirements needed to explore the application, and discussion of economic tradeoffs in employing a major process recovery system.

INTRODUCTION

The use of heat pumps in the residential and commercial sectors have existed for a long period of time. These applications have typically utilized an intermediate refrigerant loop to capture energy from low temperature sources. Following is a description of a new concept termed the open cycle heat pump which may be used to economically recover this heat.

A schematic diagram of the process recovery equipment is shown in Figure 1. The numbered areas on the schematic diagram correspond to the thermodynamic states of the fluid shown on the temperature-enthalpy diagram of Figure 2.

The waste water stream (1) at temperature T_1 enters a throttling control valve which decreases the pressure of the water. The water leaving the control valve (2) is below the saturation pressure for the temperature T_1 and therefore exits as a two-phase mixture. This two-phase mixture enters a flash chamber which is maintained at a low pressure by the suction of the compressor. The flash chamber separates the liquid portion (3) of the waste stream from the steam portion (4) by gravity. Typically, 2-4% by mass of the incoming flow will be flashed to steam while the remaining liquid is pumped back into the waste water system. The discharge liquid is of a lower temperature than the liquid before flashing, since the liquid's sensible heat is the source of the latent heat of the steam which is produced in the flashing process. Saturated steam (4) enters the compressor where it is compressed to a pressure high enough to use for process heating. In this report, we will discuss only those industrial process heat pumps which produce steam from liquid water.

Hardware has been developed to incorporate this process recovery cycle into an industrial application. A description of the industrial application, equipment utilized and economic parameters comprise the remainder of this paper.

PROCESS RECOVERY SYSTEM APPLICATION

An industrial application of this new process recovery technology was identified at a large chemical manufacturing operation located in Selkirk, NY. The chemical plant is part of the Noryl^R Products Division of the General Electric Company which manufactures a family of thermoplastic resins under the trademark of Noryl^R. These resins are characterized by high heat deflection temperatures, excellent dimensional stability, extremely low water absorption, high impact strength, excellent mechani-

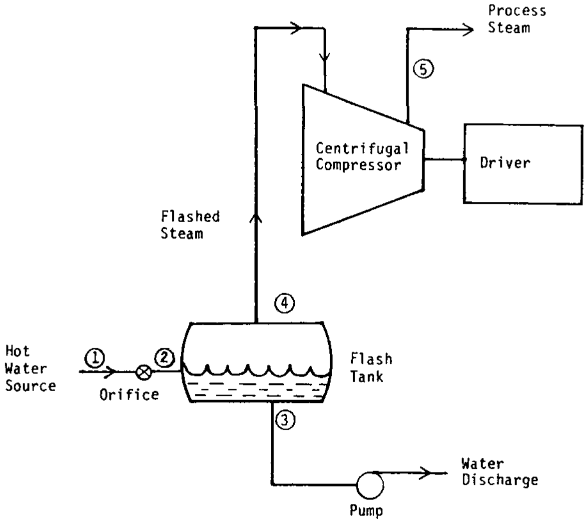

FIGURE 1 SCHEMATIC DIAGRAM OF OPEN CYCLE HEAT PUMP SYSTEM

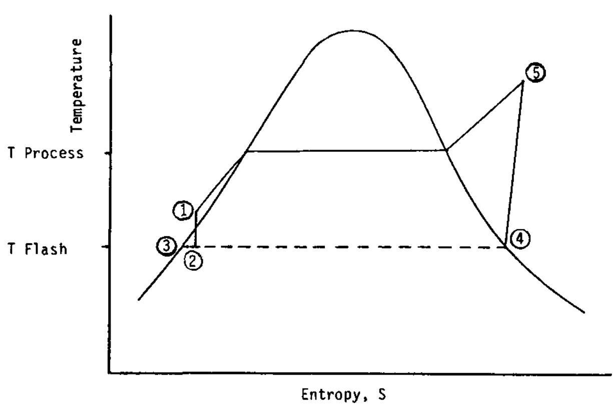

FIGURE 2 TEMPERATURE-ENTROPY CHART FOR STEAM SHOWING OPEN CYCLE HEAT PUMP CYCLE

cal and electrical properties, and broad U.L. recognition. Applications include every major industry, including appliances, automotive, business machines, television, liquid handling, construction and electronics.

Like most chemical process plants, Noryl^R operates a large number of heat transfer operations at the site. Many of these require that the process streams be cooled by a tempered water system. Return water temperatures can reach 195°F before the cooling for recycle. It is this source of heat that is available for a heat recovery operation.

The present tempered water loop on the site is a closed system circulating water from the hot process to a bank of fin fan coolers. Approximately 100 MM BTU's per hour are removed from the process and liberated to the atmosphere in this fashion. By physically tieing into this water source and diverting 3000 GPM of the water through the heat recovery operation, cooler water will be returned to the process, fewer fin fan coolers will be required, and useful steam will be produced.

Several factors had to be reviewed before a heat recovery system such as this could be integrated into the plant. The average flow and temperature of water was determined to find out how much heat was available. Low pressure steam users were identified to make use of the newly available energy from the heat pump system. Control schemes were developed to integrate the heat pump system into the existing plant's operation from both the water and steam side.

The tempered water loop including the proposed Process Recovery System is shown schematically in Figure 3. The open cycle Process Recovery System can utilize a portion of the available energy (which is presently discharged to the atmosphere) to provide over 30,000 lbs/hr. of process steam.

DESCRIPTION OF EQUIPMENT

The large hot water source from the tempered water loop is delivered to a flash tank. The flash tank is a cylindrical carbon steel tank twelve feet in diameter and twenty feet long. Water enters the tank through a water box where it is forced through a stainless steel orifice. The water flow continues over a separation plate to allow steam to be liberated from water and delivered to the compressor. A subatmospheric pressure is maintained in the tank by the suction of a six stage centrifugal compressor. The flashed steam passes through a demister (steel mesh design) while the water not flashed to steam is pumped back to the process. The tank is fitted with

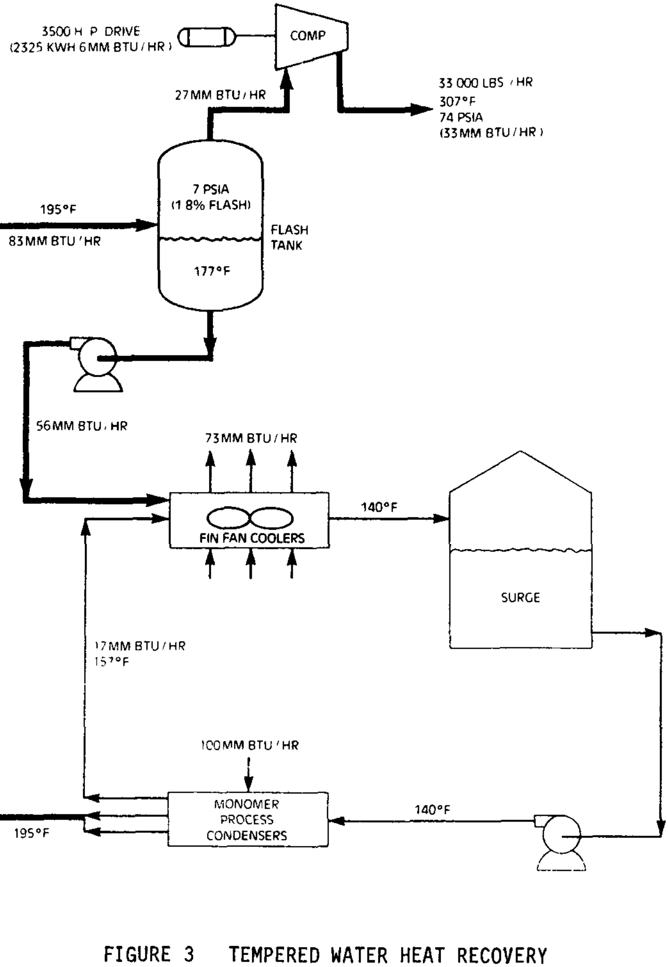

FIGURE 3 TEMPERED WATER HEAT RECOVERY

level, temperature and pressure sensors to maintain the process within specified operating parameters.

Steam enters the suction of a six stage centrifugal compressor where it is compressed up to useful process steam pressures. The heart of the compressor used in this application is a six stage rotor having an open impeller on the first stage followed by five closed impellers. The rotor normally operates at 12000 RPM enabling compression ratios in excess of 10. This gas path is sealed with a conventional steam sealing arrangement widely used for rotating equipment in the process industries. The rotor is supported by tilting pad journal bearings which act to dampen vibration and respond to unbalance. The compressor has a fabricated carbon steel casing which holds the stainless steel diaphragm bundle. The compressor is fitted with standard vibration, temperature and pressure sensors to assure safe, dependable operation.

The compressor is coupled to a motor and speed increasing gear by diaphragm-type couplings. The speed increasing gear is of a standard double helical gear design enabling the compressor train to use only one thrust bearing. This advantage means an improvement efficiency of 1-2% on the gear performance; thus improving the overall train performance.

The driver for the compressor train is a standard 3500 HP induction motor providing constant speed to the base loaded process recovery equipment. Both the gear and motor have sensors for bearing temperatures and rotor vibration which are transmitted to a remote computer based monitor panel for alarm and trip sensing.

The compressor, gear and motor are mounted on a common base with factory piped and wired auxiliaries for ease of installation and compactness. The lube system is incorporated into the process recovery system base and provides the needed oil service for the rotating equipment. Steam sealing is also factory piped on the skid using a small portion of the process recovery steam to seal the shaft ends. This steam is then extracted from the seals with a steam ejector which uses a small portion of the steam discharged from the compressor for motive steam. The ejector discharge gases are then piped to a gland condenser where the non condensable gases are vented and the condensate piped to a chemical sewer.

It is expected that the process recovery system will be base loaded to supply a large portion of the plant's steam demand. The plant would normally supply steam to the low pressure steam header using a standard reducing valve from the 150 psig header. However, it will be shown that it is much more cost effective to use the process recovery system to provide this steam using energy normally discarded in the tempered water loop.

ECONOMIC EVALUATION

The Process Heat Recovery System at the Noryl^{R} Products Department is designed to produce 33,000 lbs/hr of steam at 60 psig. To do this, the motor skid requires 2500 kw of electrical energy to run the compressor and other auxiliaries. With a charge of 5¢/kwh, steam is being produced at a cost of $3.80 /1000 lb.

To evaluate the economic attractiveness of generating steam using this new technology, an evaluation of the alternatives available and the relative costs of each method was conducted. The alternative to the process recovery system generating steam for process use is an oil-fired boiler located on site. The boiler uses #6 fuel oil to generate process steam need on site. Using fuel oil costs of 75¢/gallon and a boiler efficiency of 80% yields a steam cost of $6.30/1000 lbs for steam generated by the boiler.

Therefore, the cost of steam produced by the process recovery system is only 60% of the cost of steam produced by the boiler. A net savings of $2.50/1000 pounds of steam is realized by the users. For a typical chemical plant operating 8400 hours/year, this cost savings translates into approximately a 700,000 dollar a year savings in steam generation costs.

SUMMARY

The Process Recovery System discussed in this paper is applicable to many large hot gas or liquid streams. Applications for this new technology exist in the chemical, paper and food industries. In general, the cost of steam produced by the Process Recovery System is much less than boiler produced steam, especially in oil-fired boiler applications. With the ever-changing energy picture the Process Recovery System offers a cost effective energy conservation alternative.

OPEN-CYCLE VAPOR COMPRESSION HEAT PUMP SYSTEM*

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1. INTRODUCTION

In many industrial processes, large quantities of waste energy are often liberated in the form of:

- Low-pressure waste steam
  - Clean
  - Contaminated

- Low-grade waste heat
  - Sensible heat of liquids or gases
  - Latent heat of condensible gases

Economical recovery of these waste energy sources is often difficult due to such factors as low-temperature levels and contamination of the steam. In industrial processes that utilize steam directly or as a mode of energy transport, waste energy can be efficiently recovered and upgraded in the form of high-pressure steam by means of an open-cycle steam heat pump system. Recovery and upgrading of these waste steam or heat sources offer a great potential for energy conservation.

Thermo Electron has developed an open-cycle steam heat pump to recover this waste energy in the form of high-pressure process steam. The system utilizes excess low-pressure steam (or that produced from an excess heat source with a waste heat boiler) and compresses this steam to the

*This work is supported by the Gas Research Institute, Southern California Gas Company, and the Consolidated Natural Gas Service Company.

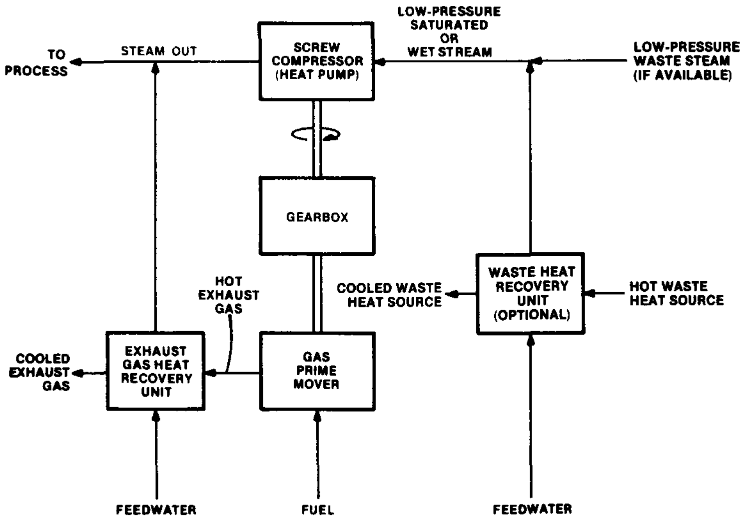


Figure 1. Flow Schematic of Steam Heat Pump System

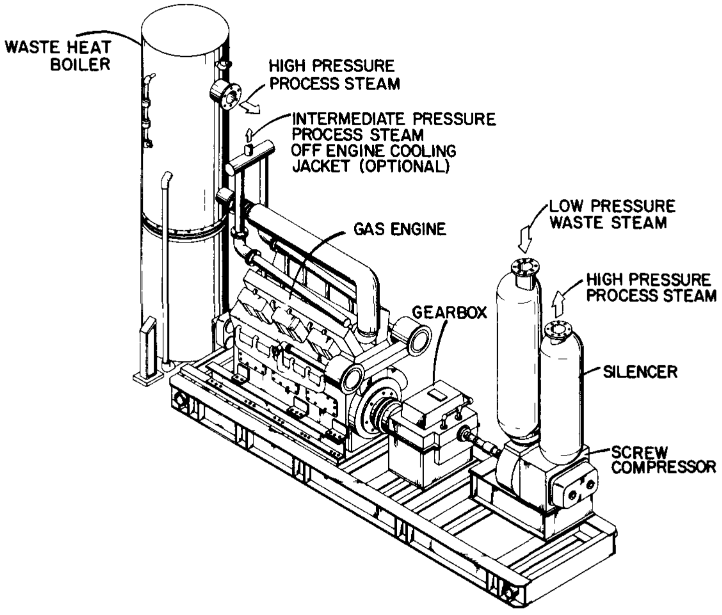


Figure 2. Steam Heat Pump System

desired pressure level for process use. The compressor is driven by a gas turbine or gas engine prime mover. To enhance the system performance, the prime mover exhaust and/or cooling jacket heat is recovered to generate additional process steam or hot water. Utilizing the Thermo Electron system, fuel consumption can be as low as 30 percent in comparison to a direct-fired boiler. Simple payback periods of 1 to 3 years are generally found for most applications.

2. STEAM HEAT PUMP SYSTEM DESCRIPTION

A flow schematic of the heat pump system is shown in Figure 1. In operation, low-pressure steam, which is directly available or generated from low-grade waste heat in a waste heat boiler, is mechanically compressed to high pressures, thereby increasing its condensing temperature to the level required for process use. A key feature of the system is the use of a positive displacement rotary screw compressor. The compressor provides high-pressure ratios up to 7:1, is capable of handling wet and contaminated steam, has excellent turndown characteristics for part-load operation, and comes in sizes typical of the majority of industrial applications encountered. The work of compression is supplied by a gas engine or gas turbine. The temperature of the products of combustion from the prime mover are at approximately 800° to 1000°F; therefore, this energy can be used to generate high-pressure steam directly in the system's own waste heat recovery boiler. Also, with a gas engine, the cooling jacket heat can be used to make low-pressure (15 psig) steam or hot water.

An illustration of the system is shown in Figure 2. It consists basically of a rotary screw compressor, gas engine prime mover, speed increaser (gearbox), waste heat recovery heat exchanger or boiler, and control system. The following is a short description of these components.

Compressor

To achieve maximum performance and reliability, the choice of the compressor is critical to the system. In evaluating the compressor, it was found that basically three compressors, centrifugal, axial, and rotary screw, showed the greatest potential for successful operation with steam.

Centrifugal and axial compressors achieve compression based upon aerodynamic operating principles. Both of these compressors have the capability of handling large flow rates up to 200,000 cfm, but because of their high rotating speeds are very sensitive to water droplets that can cause blade erosion. These compressors are also limited to operation over a rather narrow range of operating conditions, due to either surging or unacceptably low efficiency.

The rotary screw, however, is widely used for compressing two-phase fluids and therefore was selected for use in Thermo Electron's system. This is a positive displacement machine consisting of two mating helically grooved rotors, one male and the other female, operating in a stationary housing with suitable inlet and outlet ports. No inlet or discharge valves are required. In operation, inlet gas is pulled into a void created by a pair of spiral rotors, as shown in Figure 3. As rotation occurs, the incoming gas is cut off from the inlet and compressed by the meshing rotors as it is moved along the axis of the machine. At some

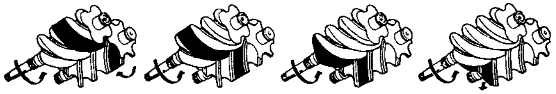
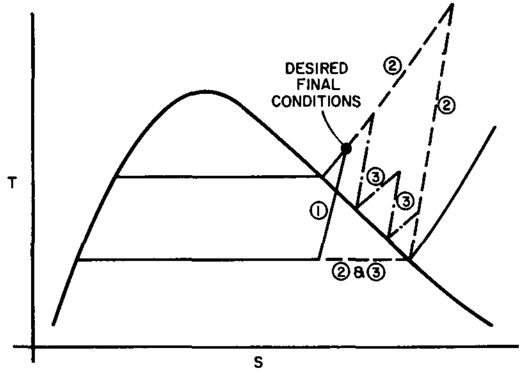


Figure 3. Screw Compressor Operation



① DIRECT COMPRESSION OF TWO-PHASE MIXTURE TO DESIRED CONDITIONS

② DIRECT COMPRESSION OF DRY SATURATED STEAM TO DESIRED PRESSURE FOLLOWED BY LIQUID INJECTION TO DESIRED TEMPERATURE

③ MULTI-STAGE COMPRESSION WITH INTERSTAGE LIQUID INJECTION

Figure 4. Possible Compression Paths

point, depending on the compression ratio built into the machine, discharge ports are uncovered and the compressed gas is discharged.

This type of machine is built in a wide range of sizes and is characterized by good volumetric and adiabatic efficiencies over a range of 50 to 100 percent of maximum capacity. Flow and horsepower are proportional to speed, and speed variation is the most efficient method of capacity control. Flow capacities up to 22,500 acfm are available in a single unit. An internal compression ratio is built into the machine and operation at an external pressure ratio other than the built-in compression ratio results in some loss in efficiency. Screw compressors are available with built-in compression ratios up to 7:1 for single-stage units and 14:1 for two-stage units.

The screw compressor has a number of unique characteristics which make its application best suited for mechanical vapor recompression. Because of the relatively low velocities and smooth fluid flow path along the rotors, the machine is capable of compressing two-phase fluids without damage. In addition, at high-pressure ratios, intercooling is not necessary when compressing two-phase fluids because the work which normally goes into producing sensible heat during the compression process simply causes additional fluid to evaporate. This makes the process more nearly isothermal, and in doing so minimizes the work of compression.

Several different thermodynamic paths may be followed during the compression process. These paths, shown in Figure 4, are: (1) compression of a two-phase wet mixture of appropriate quality to final conditions, (2) compression of dry saturated steam to final pressure, with final temperature attained by the addition of liquid to the superheated vapor, and (3) multistage compression with liquid addition between stages. The theoretical performance of a compressor operating under these three conditions is shown in Figure 5.

The screw compressor, because it is able to compress wet steam, has the potential of following the first path, which requires the least work of the three potential paths because the fluid remains homogeneous and in thermodynamic equilibrium during compression. If the steam were to first be dried, as would be required for centrifugal or axial machines to avoid erosion damage, the second or third paths would be followed, both of which are less efficient than the potential path followed by the screw compressor.

In addition to being able to compress wet steam, the screw compressor also has the potential capability of compressing steam containing condensible and noncondensible gases and particulate matter. Because the screw compressor is a positive displacement machine, it is not dependent on aerodynamic effects, as are centrifugal and axial compressors, to achieve the desired pressure rise. As a result, high relative velocities are avoided and erosion minimized. Axial and centrifugal compressors, because of their high-speed operation, are very sensitive to rotor imbalance. Erosion of turbine blades or rotors, in addition to reducing performance, may result in dynamic imbalance and potential mechanical failure. The rotors in a screw compressor are relatively massive in size and slight erosion or corrosion tends to have little effect on dynamic stability, although it will affect performance. Buildup of foreign matter also does not

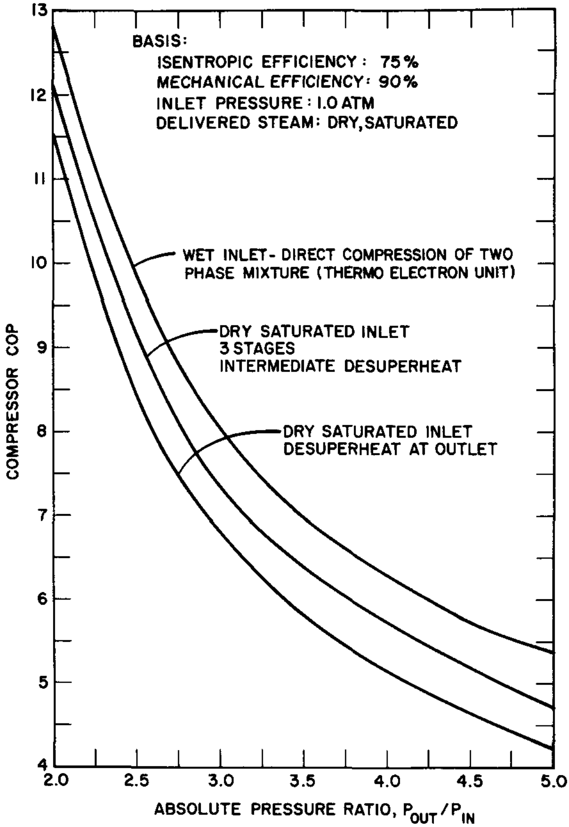


Figure 5. Compressor Coefficient of Performance at Various Compression Paths

have a large effect as would be the case with centrifugal and axial machines. In fact, such buildup may actually improve performance as a result of better sealing.

Another advantage of the screw compressor for contaminated steam operation is that being a positive displacement device, it will pump against whatever pressure is required to achieve a given flow so long as adequate power is available. Under circumstances where fouling of equipment would entail an increase in pressure to achieve the desired flow, the screw compressor performance would still be satisfactory; while centrifugal and axial machines, being constant pressure devices, would be forced to operate at reduced flow rates.

Prime Mover

The selection of the prime mover is also of marked importance to the system performance and economics. For gas turbine or gas engine driven systems, there are a number of important factors to consider depending on the specific application. They include: (1) specific fuel consumption or efficiency, (2) exhaust gas temperature and flow, (3) cooling requirements, (4) size and weight, and (5) costs. The first three factors determine how efficiently the input fuel energy is converted to shaft power for driving the compressor and how much of the remaining waste heat can be recovered to generate additional steam or hot water. The size and, most important, cost of the prime mover help determine the economic feasibility of the system.

Gas turbines are small in size for their horsepower ratings but also have relatively high specific costs. Efficiencies are relatively low at about 20 to 25 percent (HHV). However, because the losses are in the form of high-temperature exhaust products, a large fraction may be recovered in a waste heat boiler to generate additional high-pressure steam. Gas turbines are not well suited for part load or variable speed operation without a significant loss in efficiency.

Gas engines on the other hand are large in size relative to their horsepower rating. Efficiencies are approximately 30 to 35 percent. Gas engines lose about 30 percent of the fuel input energy in the cooling jacket which may be recovered as low-pressure steam (30 psia) and if desired, recompressed in the system. Another 30 percent is lost in the exhaust products which may be recovered as high-pressure steam in an exhaust waste heat boiler. Gas engines have good power and speed turndown capability to about 50 percent without significant loss in efficiency.

Excess Heat Boilers

Waste heat boilers are commercially available to generate steam from hot gas or liquid streams. Sizing boilers involves a trade-off between heat exchanger effectiveness, excess heat temperature and flow rate, and cost. When utilizing a gas engine prime mover, the heat in the exhaust gas may be recovered as high-pressure process steam. In addition, the engine cooling jacket and/or exhaust gas heat may be used for boiler feedwater preheating or other applications.

Control System

The control system must regulate the steam flow rate through the compressor based upon the availability of waste supply steam or that produced in a waste heat boiler, and/or the output demand requirement for steam. It must also regulate the desired quality or degrees superheat of the output steam for varying steam conditions. Flow control through a screw compressor is generally accomplished by suction throttling, bypass, or blowoff, and speed variation. Speed variation is the most efficient method of capacity control. Since the screw compressor is a positive displacement device, the flow rate and power requirement are basically proportional to the compressor speed. Suction throttling and bypass control provide flow control for fixed speed operation; however, there are no power savings with these methods.

Miscellaneous Components

Additional system components include a speed increaser (gas engine prime mover) or speed reducer (gas turbine prime mover) gearbox to properly match the prime mover speed characteristics to the compressor; a lubrication system for the compressor and gearbox bearings; a base frame for mounting the individual components; couplings to connect the various components and act to control torsional oscillations; and miscellaneous pumps and heat exchangers.

3. ENERGY SAVINGS AND SYSTEM ECONOMICS

The amount of energy saved by means of a steam heat pump system is dependent on the performance of the prime mover as well as the compressor and other individual components. Figure 6 illustrates the predicted energy savings for both gas engine and gas turbine prime movers. For absolute pressure ratios between 2 and 6, respectively, energy savings of approximately 70 and 40 percent compared to a conventional direct-fired boiler can be achieved. This unique aspect of the system is a result of the fact that the major fraction of the energy in the steam is already available to the compressor as latent heat. As a result, only a small fraction of additional energy is required to raise its pressure and temperature to a useful level. As the pressure ratio increases, the energy savings decrease due to the additional work of compression.

Although significant energy savings can be realized by vapor recompression, such a concept must also be justified economically. The justification for such industrial equipment is often expressed in terms of the simple payback period, which is equal to the initial capital costs divided by the net annual energy savings. Although detailed cost and performance estimates of the system must be determined on an individual basis, it is nevertheless possible, given certain assumptions, to predict the general trends based upon the: (1) process steam flow rate, (2) pressure ratio, and (3) excess heat temperature and flow if a waste heat boiler is necessary. Typical steam payback analyses for waste steam are shown in Figure 7. These analyses are based on: a gas engine prime mover, fuel costs of $\$5/10^6$ Btu, 8400 annual operating hours, and a boiler efficiency of 85 percent.

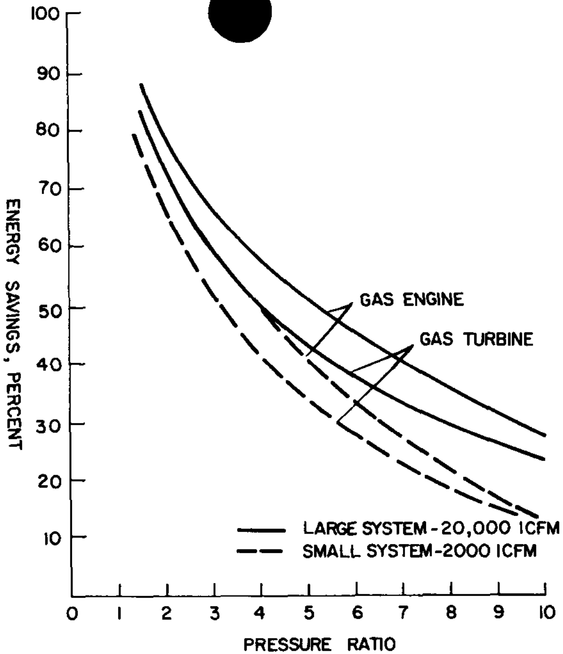


Figure 6. Cost Savings with Steam Recompression Over Direct-Fired Boiler

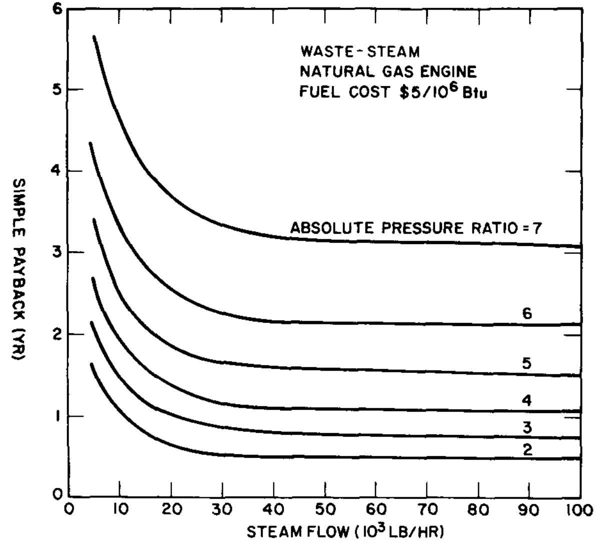


Figure 7. Simple Payback Period as Function of Steam Flow Rate and Pressure Ratio

For a given steam mass flow rate, the payback period increases as the compressor pressure ratio increases. This is simply because the compressor specific power requirement increases, reducing the savings over a direct-fired boiler. The most favorable payback times are obtained for pressure ratios of 5 or less, and flow rates of over 15,000 lb/hr. Simple payback times can often be less than one year for this situation.

4. STEAM HEAT PUMP DEMONSTRATION SYSTEM

In the design of a steam heat pump system operating at high pressure ratios, the compressor is the major component whose application for compression of steam represents the most uncertainty. Of the various types of compressors, axial, centrifugal, reciprocating, and rotary screw, only the screw compressor has shown itself to be insensitive to liquid in the working fluid. Recognizing the large potential of the screw compressor, Thermo Electron undertook a development program sponsored by the Gas Research Institute, Southern California Gas Co., and Consolidated Natural Gas Service Co. to develop a gas-fired steam heat pump system utilizing a rotary screw compressor.

In the first phase of development a relatively small (750 cfm) screw compressor was modified for steam service and tested to evaluate the performance and operating characteristics. The compressor was operated over widely varying conditions and scaling information was gathered. The performance of the compressor, while not expected to be as high as larger machines, was found to be completely satisfactory for its size and as shown in Figure 8, in excellent agreement with predicted performance.

A complete system was then designed, built, and tested at Thermo Electron. A photograph of the system is shown in Figure 9. The system is based on a 2200-cfm screw compressor with a built-in pressure ratio of 3:1. The compressor is driven by a 500-hp industrial gas engine. The system includes all the major components of a full-scale unit.

The design specifications for the system are listed in Table 1. The system is designed for a nominal steam flow rate of 10,000 lb/hr at an inlet pressure of 30 psia and an outlet pressure of 90 psia. The performance of the heat pump system compared to an 85-percent-efficient direct-fired boiler is shown in Figure 10. As would be expected, the system performance is most sensitive to the pressure ratio, with fuel savings ranging from approximately 70 to 40 percent over a pressure ratio of 2 to 4 respectively. The differences in performance at a given pressure ratio are the result of differences in engine efficiency and compressor performance at the various operating speeds and power levels. The system has operated for over 650 hours under various laboratory conditions. System operation has been completely satisfactory demonstrating the engineering concept and applicability of the mechanical design.

The steam heat pump system has now been installed at the Monsanto Plastics and Resins Company in Indian Orchard, Massachusetts, for long-term operation under industrial conditions.

Figure 11 is a flow diagram of a heat pump system application. The system will be used to recompress the exhaust from a steam turbine drive for use in a new manufacturing process. The steam is currently vented

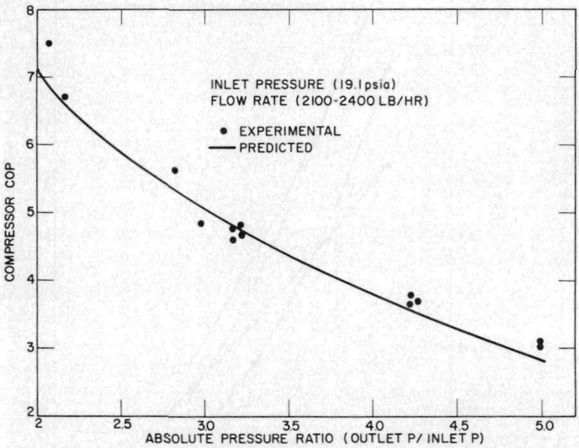


Figure 8. Experimental and Predicted Compressor Performance

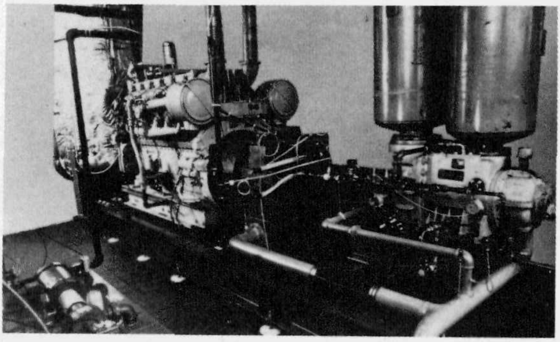


Figure 9. Steam Heat Pump System

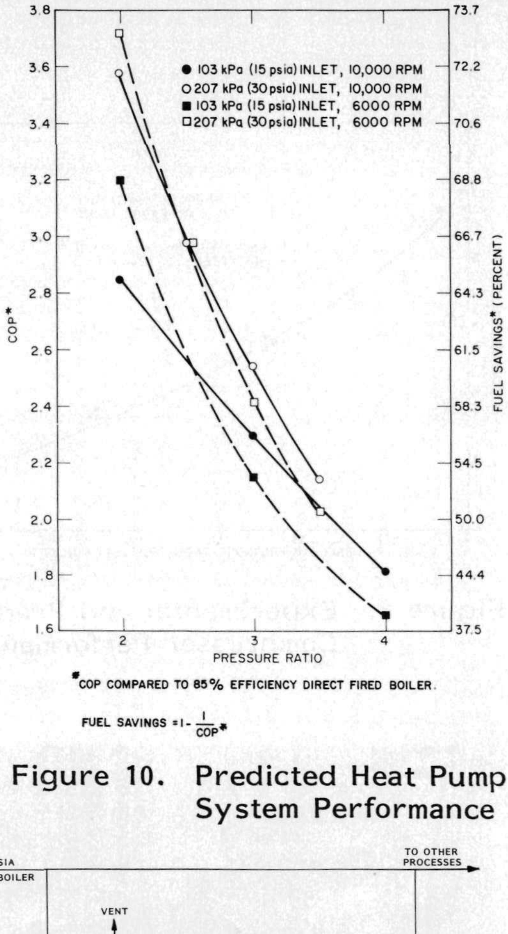


Figure 10. Predicted Heat Pump System Performance

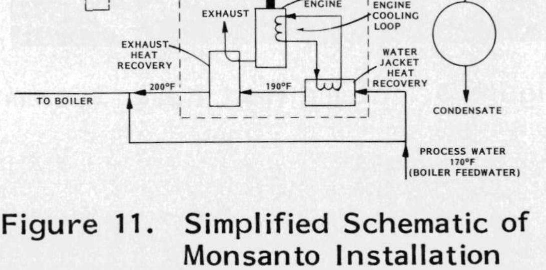


Figure 11. Simplified Schematic of Monsanto Installation

to the atmosphere. The heat from the engine cooling jacket and exhaust is being used to preheat the boiler feedwater. Table 2 gives an energy profile of the system application. Energy savings of over 63 percent compared to steam generation in their present direct-fired boiler is expected.

TABLE 1

SYSTEM DESIGN SPECIFICATIONS

	Overall Operating Range	Nominal Design
Steam Flow Rate (lb/hr)	3000-15,000	10,000
Inlet Pressure (psia)	15-45	30
Outlet Pressure (psia)	30-105	90
Pressure Ratio	2-6	3
Input Power (hp)	220-550	480

TABLE 2

ENERGY PROFILE FOR MONSANTO DEMONSTRATION SYSTEM

Steam Inlet Pressure	20 psia	
Steam Outlet Pressure	60 psia	
Steam Flow Rate	5600 lb/hr	
Hot Water Flow Rate	90 gal/min	
Heat Pump System Fuel Input	3.13×10^6 Btu/hr	
Heat Pump System Energy Output		
Heat Pump	5.13×10^6 Btu/hr	(80%)
Engine Jacket	0.87×10^6	(13%)
Engine Exhaust	0.43×10^6	(7%)
Total	6.43×10^6 Btu/hr	
Coefficient of Performance	2.05	
Fuel Input to Direct-Fired Boiler for Equivalent Energy Output of Heat Pump	8.38×10^6 Btu/hr	
Energy Savings Over Direct-Fired Boiler	5.25×10^6 Btu/hr	(63%)

5. CONCLUSIONS

The steam heat pump energy recovery concept represents a simple and viable approach for the ultimate conservation of fossil fuel in the U.S. industry. In all industries where steam (or vapor) is utilized within a process or a series of processes, the steam heat pump, through mechanical vapor recompression, has the potential for reducing energy consumption up to 70 percent over a direct-fired boiler.

The Thermo Electron steam heat pump can deliver high-pressure and high-temperature steam (or vapor) by compressing low-pressure waste steam (or vapor) commonly found in steam vents and in the exhausts of evaporators, dryers, and turbines.

Other applications include waste energy recovery from hot exhaust or product streams, where low-pressure clean steam (or vapor) is first generated in a waste heat boiler and then recompressed to a usable process pressure level.

Depending on energy costs in a given region, most applications show a simple payback of one to three years.

Long duration operation of this steam heat pump system will be of significant importance towards demonstrating the applicability of waste energy recovery utilizing this concept and promoting its use in industry.

ICE PONDS FOR AIR CONDITIONING AND PROCESS COOLING

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THE CONCEPT

An ice pond is a mound of porous ice made by water sprays exposed to freezing air in winter and protected by an insulating cover to preserve the ice for cooling during warm weather. The ice is accumulated in a watertight excavated reservoir. Cold meltwater is pumped from the bottom of the ice pond to a heat exchanger used for air conditioning or process cooling. The warmed cooling water is then pumped back to the ice pond for re-cooling to 32°F. Heat is thus gradually transferred from the process or building to the ice until the following winter, when a new mound of ice is made.

Ice ponds thus harvest the renewable cooling capacity of cold winter air for use throughout the year or during the summer months. Their use is limited to regions where air temperatures are below freezing for at least several hundred hours each winter. This condition is met in most regions of the United States except parts of the Southeast and Southwest that are not at altitudes significantly above sea level.

For some applications it is advantageous to pre-cool the warmed cooling water in a spray cooling pond adjoining an ice pond before discharging the return water back to the ice.

R & D PROGRAM

The ice pond concept has been developed at Princeton University in a program that started in the fall of 1979 and has been funded by the Prudential Insurance Company of America. (1,2) The first test pond, (called P-I), built was in the winter of 1979-80 at the University's Forrestal Campus. The pond was square, about 60 feet on a side, 12 feet deep, with a 45° slope, and lined with nylon reinforced plastic sheeting. The ice was produced by a commercial snow-making machine (the SMI Snowstream 320) manufactured by Snow Machines, Inc. Approximately 1,200 tons of ice were accumulated in the ice pond during 340 hours of snow machine operation in January and February, 1980. The top of the ice pile was about 8 feet above the top of the pond berms. The average bulk density of the ice, which was porous, was about 35 pounds per cubic foot. After nearly half the ice melted its surface was covered with about 8 inches of straw sandwiched between two layers of plastic sheeting. The ice was used to cool a 2,500 square foot nearby building the following summer by circulating chilled water from the ice pond to an air-water heat exchanger in the building and back to the surface of the ice. Several hundred tons of unmelted ice remained in the pond by the end of the summer of 1980.

Following this successful demonstration of the ice pond concept, a second test pond, called P-II, was built in the fall of 1980. Its function was to test the concept in a form suitable for use to cool an office building planned for construction by Prudential at the Princeton Forrestal Center. The P-II pond is circular, with a diameter of 60 feet, and is 10 feet deep. The pond is covered by a steel arch supported fabric dome with six fabric sides that can be raised to allow cold air to enter the building during ice-making operations. About 600 tons of ice were accumulated in the P-II pond in January and February of 1981, using the same snow-making machine that was used for accumulating the ice in the P-I pond. This machine was mounted on a steel rail about 15 feet above the edge of the pond, and could be moved laterally and aimed in different directions to allow control of the placement of the ice in the pond. The maximum height of the ice pile was about 15 feet above the top edge of the pond. The [illegible] was then covered with insulating blankets of polyurethane foam sandwiched between layers of plastic sheeting, and several hundred tons of the accumulated ice were again used to cool the adjoining University building during the summer of 1981. The P-II test program successfully demonstrated that ice could be efficiently produced and stored under a permanent low cost structure. It also reconfirmed that the total electrical energy required to make the ice was substantially less than would be required to meet the same annual cooling load by conventional refrigeration.

The P-II pond was again filled with ice in the winter of 1981-82, to learn more about the ice making process under a ventilated dome, but the accumulated ice, though preserved by an insulating blanket, was not used for significant air conditioning during the summer of 1982. Several hundred tons of ice made more than a year ago still remain unmelted in the P-II ice pond.

Based on encouraging results of this test program, Prudential decided to proceed with construction of a much larger ice pond for air conditioning one of the office buildings now nearing construction as part of their ENERPLEX complex now nearing completion at the Princeton Forrestal Center.

Also encouraged by the results of the Princeton/Prudential ice pond demonstration program, in which we have actively participated since its inception, Don L. Kirkpatrick and I founded Taylor Kirkpatrick, Inc. (TKI), whose business is the design, checkout, and construction of ice ponds for commercial applications.

COMMERCIAL DEMONSTRATION

Construction of Prudential's ENERPLEX ice pond at Princeton was completed in January, 1983, and it is being filled with ice this winter. The pond is rectangular, with horizontal dimensions of 120 feet by 160 feet. It is 20 feet deep and covered by a lightweight insulated membrane dome that is 30 feet high at the center. The four bases of the steel arch supports for the fabric cover are attached to cables mounted in towers at each corner in such a way that the entire structure can be lifted 20 feet off the ground to allow unobstructed access to cold air during ice-making operations. Long term preservation of the ice from environmental melting is accomplished by 9-inch-thick fiberglas insulation attached to the under side of the fabric that forms the building dome.

The ENERPLEX ice pond will be used to cool the 130,000 square foot north building of the ENERPLEX office complex this coming summer. The pond's design capacity is 7,500 tons of ice, of which about 5,000 will provide the heat sink required for cooling the building. The ice is being made by three Boyne snow machines purchased from Snow Machines, Inc. These are mounted on wheeled carriages that can be suitably placed along the edges of the pond. The design maximum height of the accumulated ice is about 20 feet above grade level, corresponding to a maximum ice thickness of about 40 feet.

Total electrical energy consumption by the ENERPLEX ice pond is expected to be less than 10% of that required for a conventional air conditioning system to meet the same cooling load. This corresponds to annual energy cost savings in the range of $12,000 to $15,000 per year. Credit for capital cost savings does not apply to this system, since a conventional backup chiller is provided for this first commercial demonstration project. Extensive instrumentation is provided for monitoring all important aspects of performance of the ENERPLEX ice pond in a cost shared program funded by Prudential and the U.S. Department of Energy. Engineering services related to this ice pond are being provided to Prudential by TKI.

What we believe to be the world's first ice pond for process cooling was designed by TKI for Kutter's Cheese Factory, Inc., located about 20 miles east of Buffalo, New York. Funds for design and construction of this ice pond were provided by a cost sharing agreement between the Kutters and the New York State Energy Research and Development Authority. Funds have also been provided by the Authority for an assessment of the suitability of ice ponds for process cooling at industrial and agricultural facilities throughout New York State, and for a program to monitor the ice pond system performance through the spring of 1984. The project started late in September, 1982. Ice accumulation began in mid January, 1983, and the new system has been used for cooling pasteurized cream at the factory since early February. An insulating cover to preserve the ice will be installed this spring, and some of the preserved ice will be used this summer for dehumidifying air in three of the factory's cheese processing rooms.

The Kutters' new cooling system also makes use of a spray pond for precooling warmed cooling water before discharge into the ice pond. The ice pond is a square 54 feet on a side and 6 feet deep, lined with 30 mil thick sheet plastic. Its design capacity is for 650 tons of ice, much of which is above grade level. The adjacent spray pond is 54 feet by 40 feet, 4 feet deep, and also lined with sheet plastic. Ice is being made by a low cost spray nozzle system, rather than a commercial snow machine. The electric power costs of producing the ice is between 10 and 15 cents per ton of ice, less than 1/20 the cost of making ice by conventional compressor systems where electric power costs 7 cents/kw. hr. Capital cost contributions add another few cents per ton to the ice-making cost. Thus dramatic energy cost savings, compared with conventional refrigeration equipment, are to be expected from such a system.

The capital cost of the Kutters' ice pond/spray pond system is expected to be less than $20,000. Annual energy cost savings for the four cooling loads to which the system is being connected (one year-round load for cream cooling, and three process room dehumidification summer loads) will be about $2,500 per year. The savings of capital costs for conventional dehumidification equipment will be about $12,000. These savings will therefore correspond to a straight payback time, at present energy prices, of 3 to 4 years. Further energy savings are likely, however, if the present ice pond system is used, with appropriate matching equipment, to meet additional cold weather season cooling loads for which present energy costs are about $5,000/year. Such possibilities are now being examined.

FURTHER APPLICATIONS

Ice ponds can be used for a wide variety of types of cooling applications in locations with sufficiently cold winters and available land. Land requirements for ice storage depend on the application, ranging from several hundred square feet for air conditioning a house to several acres for large industrial plants or district cooling systems. Among the many applications of ice ponds are:

* Year-round industrial or agricultural process cooling.

* Exceptionally low cost process cooling for up to six months during the colder part of the year, using an uninsulated ice pond and a spray pond.

* Air conditioning of large commercial and residential buildings.

* District cooling, using a chilled water distribution system.

Where the setting, climate, and cooling needs are appropriate ice pond cooling systems can offer these advantages over conventional refrigeration systems:

* Much less energy consumption (typically by a factor greater than 20).

* Sufficiently low capital cost to save money by energy savings alone when used instead of refrigeration equipment already in place.

* Reduction of peak daily and seasonal demands for electric power.

* Lower capital cost for new or replacement refrigeration, especially for systems that require high peak cooling capacities.

* Security of cooling supply.

* Precision control of temperatures, especially near $32^{\circ}F$.

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PRACTICAL FEATURES OF ILLUMINATION WITH HIGH PRESSURE SODIUM LAMPS

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The high pressure sodium illuminants (HPS) have the potential of being the most highly efficient light sources available. Recently a number of concerns about this illuminant have been voiced which may make specifiers and designers shy away from the use of this source. I want to address these concerns so that reasoned choices concerning the use of this source can be made. It should be noted that in what follows I can only scratch the surface of the many fundemental issues involved.

Is HPS fundementally different from other acceptable illuminants? If so, are special precautions required. A light source, at a minimum should not detract from health, safety and comfort and it certainly should not detract from visual performance.

HEALTH

Health, is obviously of prime consideration. If a light source is deleterious to health it obviously fails to be useful regardless of any other characteristics it might exhibit.

There have been claims and conjectures that by reason of its difference from sunlight, HPS is unhealthy. However, there is no intrinsic reason why one should expect health difficulties, nor are these assertions based on any satisfying data.

Light is light. A photon of a "green" wavelength from the sun is precisely the same as any "green" photon from any source, be it an incandescent lamp, a candle, HPS or a fluorescent lamp, and will have therefore, the same visual and physiological effects. True enough; but what about the possible affect of the difference between the wavelength composition of HPS and sunlight?

The thesis that human health requires of an illuminant the same spectral composition as sunlight is based on misconceptions concerning human evolution and the way light interacts with biological organisms. Consider first, that the light that one experiences is not simply the light of the illuminant but rather is determined in large part by the colors of the objects that make up the environment. When the light from the illuminant strikes colored surfaces it experiences a change of spectral composition. Thus, the light that reflects from a green wall, for example, will have a considerably smaller proportion of long wavelength light(i.e., "red") than the illuminant. The reason the wall is green is that it absorbs more strongly the "red" wavelengths than the "green" ones. A blue object reflects the short wavelengths preferentially, and so forth. Thus, the light coming to the eyes and skin is very different from that of the illuminant. Only in a totally white or neutral grey environment would the spectral composition of the illuminant be preserved. Thus the simple desire to use a sunlight simulating spectral distribution as an illuminant, in order to provide a "natural" illumination environment is not readily accomplished.

Simply accomplished or not, should we nevertheless strive to reproduce that "natural" photic environment? Before we consider whether or not we should emulate that natural light environment we must ask what is meant by the "natural" photic environment. It has been generally held to mean that light to which the human is physiologically and visually adapted, by virtue of a long evolutionary development. This position seems most reasonable. Assertions have been made that the light responsible for human evolution is sunlight.(1) However the data of paleoanthropology, physiology, and of the visual sciences strongly indicate that the evolution of the primates occured in the forest and that homo sapiens as a result, is adapted to this forest light.(2)

The chlorophyl in foliage absorbs both the "red" and "blue" wavelengths preferentially, leaving predominantly a "greenish" spectral distribution. That is of course, precisely the reason foliage is green. Figure 1. shows the measured spectral composition of a forest light(3) compared to both that of sunlight, and to the eye sensitivity of the human. Note how closely the eye sensitivity of the human is adapted to the predominant wavelength of this "natural" light. It is highly unlikely that this correspondence is a mere coincidence.

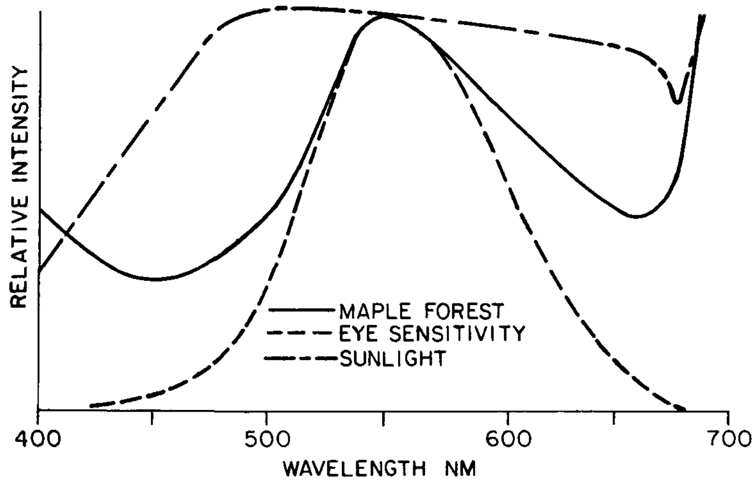

Fig.1 Comparison of the human spectral sensitivity to that of forest light and sunlight.

Also consider how poorly adapted the human is to sunlight. Sunlight causes cancer, cataracts, sunburn and degredation of the retina.(4)(5)(6)(7) The human cannot even fully adapt to the intensity of open sunlight, which causes squinting or the resort to sunglasses. After a time in sunlight the ability to see in lower light levels is reduced significantly. Furthermore, low light vision may be impaired for days after sunlight exposure.(8) Note that plains animals do not suffer such difficulties, being adapted to that intense illumination.

Further, clinical problems traceable to the use of artificial illumination have not been observed. After all, almost all artificial illuminants differ markedly from sunlight. What is most ironic is that the artificial source that has up to now received the most disapproval, the cool white fluorescent lamp, has a spectral composition quite similar to that of forest light. Figure 2.

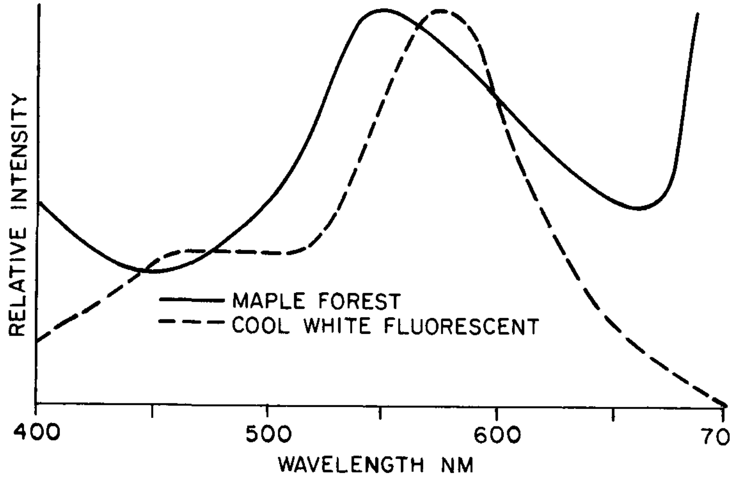

Fig. 2 Spectral composition of light in a maple forest and that of a cool white fluorescent lamp.

There have been a number of animal experiments which purport to bolster the claim that illuminants that differ from sunlight are deleterious to health. Are these to be ignored? This experimental data has been called into serious question both because of the dubious experimental procedures employed, as well as unproven and disputable interpretations of the data.(9)(10)(11)(12) It is important to realize that the animals employed in these investigations are without exception nocturnal mammals. Such creatures owe their evolutionary development to an environment which is devoid of sunlight. These animals are so poorly adapted to an illuminated environment that they often become blind in the laboratory when they are forced to suffer illumination levels which are considerably lower than sunlight. Yet these investigators stipulate that sunlight for these animals is the "natural" photic environment, and presumptiously declare that any difference between the physiological development of these animals observed under the sunlight simulating and the test illuminants, is unhealthy, and due to the lack of sunlight. This, in spite of the incontestable fact that sunlight is a most unnatural illumination for nocturnal animals! It is simply incongruous to extrapolate and apply such conclusions to the diurnal animal, homo sapiens.

There have been reports of headache, eye strain, nausea, etc. due to HPS illumination. Such reports focus attention on a very important aspect of lighting design with HPS. This source is an extremely bright one. If improperly used it can lead to all kinds of visual problems, problems of the very type which would be expected to produce such complaints as eyestrain, headache etc. Since HPS is a relatively new and readily identifiable source, these types of problems are most often assigned to the lamp, per se, rather than to a possible problem of lighting design. The classroom difficulties that have received so much publicity can be traced to the lighting design. Very high luminance ratios were observed. Glare was a significant factor, as was extremely high light levels. Bright sources must be handled with care. Whatever difficulties postulated as intrinsic to HPS, they cannot be evaluated in an environment that suffers from poor lighting design.

COLOR RENDITION

HPS illumination, if it does nothing else, will emphasize the sterilty of the use of the concept of chromaticity to predict the color rendering properties of an illuminant. We have at present no way to calculate how colors will be perceived under illuminants.(13) If we are to appreciate the color rendition of HPS illuminants, or of any illuminant, for that matter, one must use the eyes.

There is a common misconception that a full range of colors is not possible under HPS. This is quite inacurate. Such a misconception arises for two reasons primarily from the concept of the Color Rendering Index and the misapplied chromaticity calculations. Secondarily, it arises from the use of side by side light box evaluation of illuminants. Chromatic adaptation is not possible when observing rendition of illuminants in such a visual construct. It must be emphasized that illuminants are not employed in practice in the same manner in which they are commonly investigated in the laboratory. Beware therefore, of conclusions based on experiments which do not recognize this limitation.

A study of the perception of surface colors in realistic conditions shows that a wide range of colors can be perceived under HPS.(14) The human visual system is extremely adaptable to changes in illumination both of intensity and spectral composition. Further, chromatic adaptation can be extremely rapid depending on familarity with the illuminant. Thus one is adapted, for example, to incandescent illumination immediately upon entering such an environment from daylight.(15) Incandescent and daylight are very much different in spectral composition yet the color changes that occur are small. It might be expected that as the public becomes more familiar with HPS a similar adaptation will occur. There is considerable anecdotal data indicating that such is already the case.

It is always been good practice to choose colored materials under the illuminant employed. This is, particularly important for HPS since pigment manufacturerers generally have not been concerned with the appearance of their products under HPS, having been concerned with the more ubiquitous sources, daylight, incandescent and cool white fluorescent. It is likely that as HPS use becomes more extensive the pigment and paint manufactureres will take an interest in the appearance of their products under HPS. Indeed, the Sherman-Williams paint company has already issued a paint chart for paints suitable for use in an HPS illuminated environment. These include the important

OSHA safety colors as well. The chart includes some 50 paints covering a wide range of colors.

VISUAL PERFORMANCE

There is a considerable body of experimental data which demonstrate that the spectral composition of an illuminant does not affect visual performance of achromatic tasks. Colored tasks present a different situation. These tasks can be enhanced or degraded by particular illuminants depending on the spectral properties of the illuminant and the colored surface involved. Also, there is evidence that visual performance is degraded under illuminants which consist principally of very short wavelengths. This probably results from the foveal insensitivity to these wavelengths.(16)

Piper, nevertheless, has claimed a marginal problem with focus under HPS.(17) He speculates that inasmuch as chromatic aberation is possibly an important cue for accommodation and since the relative lack of the shorter wavelengths in HPS reduces chromatic aberation, the focusing mechanism would suffer. His results appear to be in contradiction to much previous experimental data.(18)(19)(20)(21)(22)(23)(24) Charmin & Tucker, for example, have shown that although some subjects do appear to use chromatic aberation as a focusing cue they quickly learn to use other, equally effective ones when chromatic aberation is not possible.(24) Further, it should be noted that HPS is certainly not totally lacking in the shorter wavelengths. Also, Corth (25) has shown that no difference between the accomodation-convergence process could be observed between HPS illumination and daylight or cool white fluorescent illumination.

CONCLUSIONS

Careful investigations in realistic constructs and practical experience with HPS has shown that the HPS sources can be sucessfully employed in indoor lighting.(26)(27)(28)(29) In a study of the acceptability of light sources Yuan and Bennett came to the following conclusions:(30)

> "In a short term evaluation of fluorescent, metal halide, (and) high pressure sodium ...sources, appropriately presented, results of visual acuity, color discrimination tests

> and subjective responses in an office environment showed that these light sources were equally acceptable." (emphasis added)

Some examples of sucessful lighting design with HPS illuminants are listed in table 1.

Table 1. Examples of HPS Indoor Lighting Installations

Standard HPS	
Offices-	Formica Corp. Evendale, OH
Offices-	Georgia Power & Light, Atlanta, GA
Offices-	National Semi Conductor, Santa Clara, CA
School-	North Division H.S., Milwaukee, WI
Stadium-	Northern Arizona University, Flagstaff, AZ
Industrial-	Oklahoma Natural Gas, Shawnee, OK
"	-G.M.A.D., Oklahoma City, OK
"	-Convair/Gen'l Dynamics, San Diego, CA
"	-Newel Co., Glendale, CA
"	-Boeing, Auburn, WA
"	-Paul F. Beich Co., Bloomington, IL
"	-Steelcase, Inc, Tustin, CA
Deluxe HPS	
Offices-	Duquesne Light Co.,Pittsburgh, PA
Gymnasium-	United Community Church, Glendale, CA
Merchandising-	Montgomery Ward, North Riverside, IL
Shopping Mall-	Pleasonton, CA
Museum-Exhibition-	National Geographic, Wash., DC

To this should be added that based on both the experimental evidence and an understanding of the possible photobiological mechanisms there is no cause for concern over health effects due to the use of HPS illumination.

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EFFECTIVE USE OF DAYLIGHTING

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I. Introduction

Daylight utilization has been a major consideration in building design throughout history. In fact, from an historical viewpoint, daylight has been the major source of interior illumination, with electric lighting being a fairly recent development. Daylight is defined as light whose ultimate source is solar radiation, although the light may reach an interior location as a combination of direct beam, diffuse sky or interreflected illuminance.

The practice of daylighting design is both a science and an art. The design of the building fenestration determines the daylighting potential. Many factors can influence the fenestration design in any one building, including esthetic considerations, occupant requirements, energy concerns, structural or mechanical limitations, and most importantly, owner preference. Many times the architect seeks to create a particular atmosphere, or develop a building design in accordance with a certain style. These artistic concerns must be addressed while additional consideration is given to the solar/thermal performance of the fenestration. Careful analysis of all of these factors can result in a fenestration design that is both attractive and energy efficient.

Building fenestration has been estimated to account for as much as five percent of the total energy consumption in the United States, with electrical lighting accounting for an additional 5.5 percent of total energy use [1]. Thus, effective use of fenestration and lighting could have a significant impact on over 10 percent of the energy used in the United States. In addition, up to 50 percent of the energy used in commercial buildings has been shown to be due to electric lighting, with an additional energy expenditure of 15 to 20 percent due to increased cooling requirements to remove heat produced by lighting [2, 3]. This indicates that commercial buildings in particular have great potential for energy savings through optimum design and utilization of fenestration and lighting systems.

Fenestration utilization has been recognized as an effective way of reducing the energy required for illuminating buildings. However, the impact on building heating and cooling systems must also be considered before net annual benefits can be determined. Comprehensive computer programs are available for calculating the net impact of fenestration options on heating, cooling and lighting loads and energy. These programs consider the interaction between the fenestration solar/thermal/daylighting performance and the building's heating, cooling and lighting loads and energy.

The purpose of this paper is to describe daylighting design considerations, design procedures and general design guidelines for effective fenestration utilization. Results obtained from measurements and computer simulations are presented to illustrate key points and conclusions.

II. Background

Daylighting offers the opportunity to reduce annual lighting energy requirements, to reduce peak building electric loads (since peak electric loads occur during periods when exterior daylight is abundant), and to reduce peak and annual cooling energy requirements, while providing a pleasant and attractive working environment. Daylighting is effective because the luminous efficacy of solar radiation (luminous efficacy is a measure of the effectiveness of a wide-band radiation source in providing visible light) is greater than the luminous efficacy of electric lighting. In some cases, the use of daylighting results in an increase in heating energy requirements due to a reduction in heat gain to the building space from the lighting system. However, the negative impact on heating is usually more than offset by the lighting and cooling energy benefits of daylighting. Peak building heating loads are not significantly influenced by daylighting, since the peak heating load occurs during the early morning warm-up period when little daylight is available, and consequently little reduction in lighting power occurs.

Daylighting is implemented in a building through the design of the fenestration and lighting control systems. The lighting can be controlled by continuously dimming systems or switching systems, automatically or manually. Figure 1 illustrates the performance of typical lighting control systems [4]. A dimming system will maintain a fairly constant illumination level, but usually requires a minimum power level be maintained. A switching system will cause the illumination level to adjust in discrete steps, but will allow the lighting to be completely de-energized, requiring only a small amount of power for the control system.

One of the most important daylighting design considerations is providing daylight to the interior zones of a building. Perimeter building zones are easily daylit by windows, but little useful daylight penetrates beyond a depth equal to 2.5 times the ceiling height. Daylighting of interior building zones can be accomplished through the use of toplighting (skylights or clerestories) or reflective window appendages. Figure 2 shows a reflective louver design to provide for deeper penetration of daylight [5]. Toplighting is limited to single floor structures or the upper floor of a multi-story structure (unless light wells or atriums are used) however, it has been found that 71 percent of the nonresidential buildings built in the United States since 1945 have only one floor [6], and thus, could have utilized toplighting.

Other daylighting design considerations include occupant factors such as required illuminance levels, glare problems and comfort conditions. The fenestration may transmit solar heat at a rate too fast to be handled by the HVAC system, resulting in localized overheating [7]. Building occupants are rarely comfortable if required to work while irradiated with direct beam sunlight. Glare problems can occur if the fenestration component appears much brighter than the remainder of the surroundings. The problems of glare and overheating can be controlled through selective use of window management strategies, such as shades, blinds or screens.

III. Daylighting Design Procedures

There are many procedures available to evaluate the daylighting performance of fenestration options. A few of these procedures are also able to determine the combined effect of fenestration options on lighting, heating and cooling loads or energy.

The simplest design techniques use charts, graphs and/or a limited number of hand calculations to compute interior daylight at points of interest within a building. These types of procedures require as input, information concerning room and fenestration geometry, and optical properties such as reflectance and transmittance. Calculations can usually

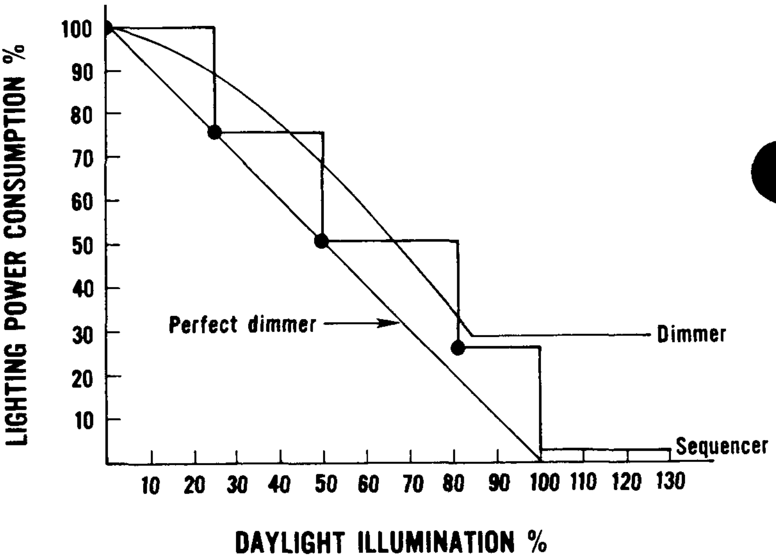

Figure 1. Performance characteristics of typical dimming and switching (sequencer) lighting control systems.

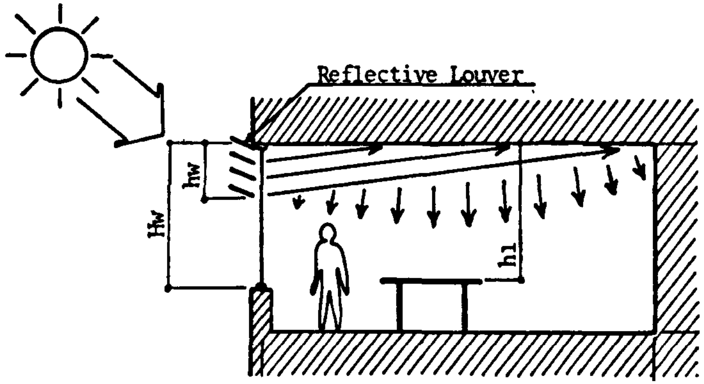

Figure 2. Daylighting with reflective louvers.

be performed only for standard overcast or clear skies, and are usually intended as design day analyses. Using these techniques, determining the annual lighting energy alone would require that the calculations be repeated for each hour of the year. Extending the analysis to include the calculation of heating and cooling loads would be extremely difficult and time consuming. Examples of these types of design procedures include the area source graphical method [illegible], the lumen method [8] and the daylight factor method [9].

The next level of design procedures includes calculations suitable for hand calculators, preferably programmable, or small (micro) computers. The basis for these types of procedures is similar to the first group, however, the format and intent are geared toward facilitating repeated calculations [10]. Yet annual analyses, and heat and cooling load calculations are still not easily accomplished with this level of design procedure.

The most accurate and comprehensive daylighting design procedures involve building energy analysis computer programs with integrated daylight calculation capabilities. While these types of computer programs require more detailed input information than the simple techniques, their output provides much more useful information, including annual heating, cooling and lighting loads and energy. Examples of this type of computer program include NBSLD-2, developed at the National Bureau of Standards [11, 12], DoE-2, developed at the Lawrence Berkeley Laboratory for the Department of Energy [13], BLAST with CEL-1, developed by the U.S. Army Construction Engineering Research Laboratory and the Naval Civil Engineering Laboratory [14, 15], and a program developed by the IBM Scientific Center [16]. Another program, LUMEN 2, has sophisticated daylighting calculation capabilities but no building thermal load capabilities [17].

These types of computer programs require access to large (main-frame) computers, but are not particularly expensive to run, considering the amount of detailed information they provide. The major expense associated with their use is the development of the detailed input data required for accurate simulation. With a little experience, the user can become quite proficient, and effectively and successfully perform building energy analyses using these types of computer programs.

IV. Daylighting Design Guidelines

The NBSLD-2 computer program is one of the few programs with the current capability of analyzing the performance of windows, skylights and clerestories [18]. A measurement program has been underway at the National Bureau of Standards for the past four years aimed towards compiling a broad data base of exterior daylight conditions [19] and the daylighting and thermal performance of fenestration systems. Based on these measurements and computer analyses, design guidelines have been developed for effective fenestration utilization for commercial buildings in the Washington, D.C. area. Because optimum fenestration design varies with building use and location, these guidelines may not be completely applicable to buildings located in areas with significantly different weather conditions, although the overall trends may be similar. The guidelines are as follows:

- For any fenestration design, the use of daylighting reduces total building energy consumption, as compared to the non-daylighting case.
- The use of daylighting reduces maximum hourly cooling loads, but does not significantly influence maximum hourly heating loads.
- When daylighting is used skylights are the most effective fenestration options in terms of minimizing annual total building energy use for heating, cooling and lighting. Figure 3 presents a comparison of total building energy use for equivalent areas of different fenestration types with daylighting.
- When daylighting is not used, minimum annual total building energy use occurs when no fenestration is used, with slightly higher energy consumption with small windows. Figure 4 presents a comparison of total building energy use for equivalent areas of different fenestration types without daylighting.
- Skylights are the most effective daylighting source, reducing electric energy consumption by as much as three forths compared to non-daylighting cases.
- Clerestory windows are more effective than wall windows of equal area, and south-facing windows and clerestories are better than north-facing ones.
- The use of fenestration with daylighting is always better than using no fenestration.
- Switching type lighting control systems should be used in building spaces where high daylight levels are expected.
- Dimming type lighting control systems should be used where uniform illuminance is required, or where the daylight levels are not expected to provide more than 75 percent of the required illumination for a significant portion of the daylight hours.
- When windows are used for daylighting, high wall and ceiling reflectances can provide three times greater daylight levels at deep locations than those provided by low reflectances.

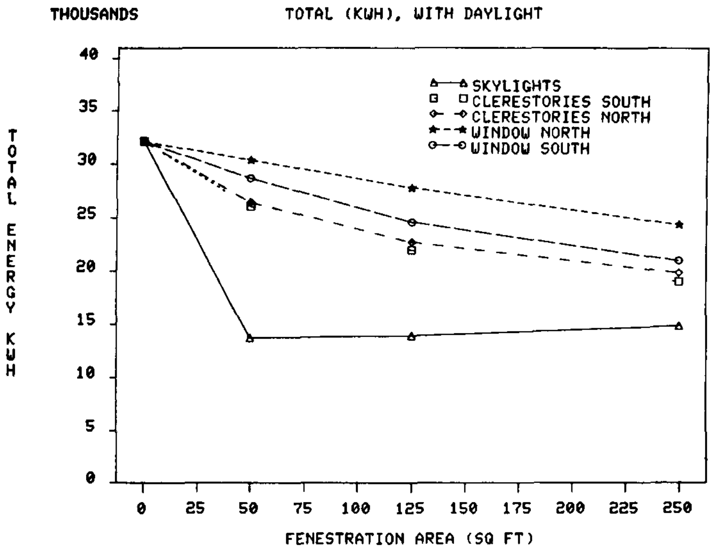

Figure 3. Total annual building energy use as a function of fenestration area with daylighting.

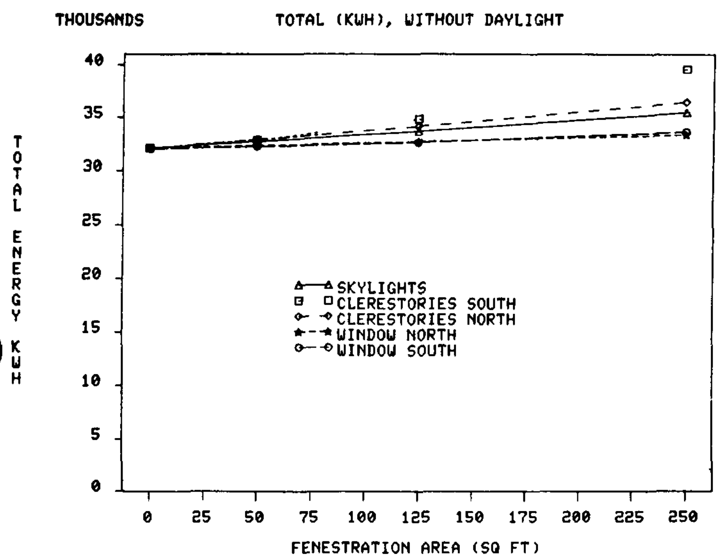

Figure 4. Total annual building energy use as a function of fenestration area without daylighting.

o Reflective louvers are particularly effective in projecting daylight deep into the building.

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WAREHOUSE LIGHTING MAX/MIN CONCEPT

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INTRODUCTION:

In a survey made of randomly selected industrial plants,it was found that a surprising proportion of floor space under roof was used for non-fabrication activities. Perhaps it is not so surprising if we consider that raw materials,in-process goods,finished products,packing materials,maintenance items,safety gear,and ready-to-ships are all integral aspects of the manufacturing process, but functionally are warehouse or storage operations.

Since this survey of a decade ago,changes to increasingly greater automation have further reduced the space in which manual operations are performed and it is therefore likely that the process of increasing storage spaces will continue to accelerate in the decades ahead.

In addition to manufacturing related work space,the distribution industry,at all levels,is also experiencing an alteration of operating patterns that results in an increase of both the required warehouse space,as well as the complexity of tasks performed in such spaces. In all instances,as the manual labor content in warehousing is reduced,the main operating costs become cost of money for investment in facility and equipment and electric energy cost.

Of the latter, lighting is a significant burden.

The MAX/MIN concept is based on achieving the most economical, energy efficient, readily maintainable kind of warehouse lighting with

MAXimum spacing of units with maximum coverage.
And
MINimum energy use with minimum operating cost expenditures.

TASK:

In most warehouses, the primary lighting task is (unlike most other working areas) not the horizontal plane or the floor. Rather, the task of visual recognition takes place on the vertical surface where the goods are kept.

Whether these goods are barrels, racks, cartons, bins, drawers, pallets, sacks or open stock --- the field of vision is from floor to top stack, on both sides of the aisle and along the entire aisle.

Hence the photometric distribution that can best provide vertical footcandles from top to bottom, and do so with the greatest spacing between units, will yield optimum over all efficacy.

TOOLS:

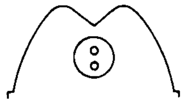
Optical design techniques make it abundantly clear that by starting from scratch and using vertical lighting performance criteria as a design objective---considerable improvements in "warehouse-aisle" lighting photometrics can be achieved.

Unlike the adaptation or modification of existing lighting fixtures which generally utilize high intensity discharge (H.I.D.) sources in a vertical burning position, this new approach to design led to the use of horizontally oriented arc tubes.

Carried one step further, and in order to carry out the efficacy objective of this MAX/MIN concept, only the most efficient generators of lumens need to be considered --namely, the sodium sources, both low pressure and high pressure.

By using a specially determined reflector contour, as in Fig. 1, for a low pressure sodium source, an asymmetric distribution of light results, as shown in Fig. 2.

Figure 1

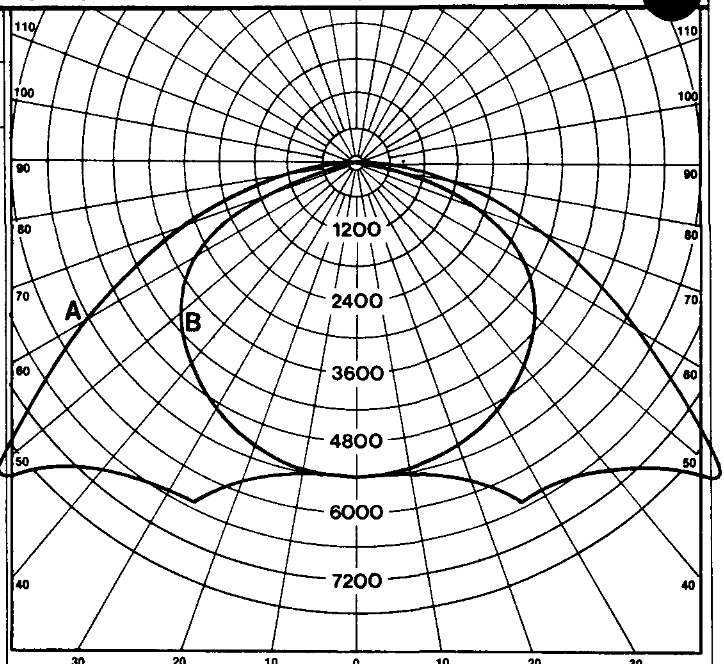


VOIGT PHOTOMETRIC TEST REPORT

Voigt Lighting Industries, Inc. Philadelphia, Penna. • Leonia, N.J.

Candlepower Distribution Data

Angle From Nadir (Degr.)	Candle-Power ALONG AISLE
0	5460
5	5430
15	5560
25	6520
35	6620
45	7580
55	6450
65	4400
75	1930
85	164



Zonal Output

Zone in Degr	Total Lamp Lumen %
0-90	76·3

Unit Tested Power-Down® No I-23-120-ASY

Description Warehouse - Spread Asymmetric Light Output

Lamp Position Horizontal A ACROSS MAIN LUMINAIRE AXIS; B ALONG MAIN LUMINAIRE AXIS

Lamp Low Pressure Sodium · SOX-180

Lumens 33,000 **Watts** 180 **Bulb** T-21

Test Distance 25 Feet **Test No** 65

Tested By Electrical Testing Laboratories, Inc **Date** November 4 1976

Approved By Norman Fad

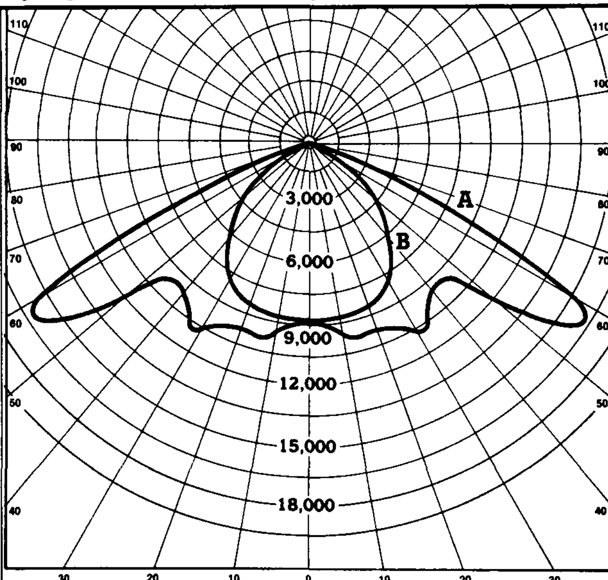
Figure 2

VOIGT PHOTOMETRIC TEST REPORT

Voigt Lighting Industries, Inc. Philadelphia, Penna. • Leonia, N.J.

Candlepower Distribution Data

Angle From Nadir (Degr.)	Candle-Power
0	8858
5	9001
10	9454
15	9761
20	9614
25	10046
30	10607
35	10012
40	9350
45	9268
50	11923
55	16021
60	13727
65	5328
70	510
75	50
80	0
85	0
90	0



Zonal Output

Zone in Degr	Total Lamp Lumen %
0-40	26 7
40-90	46 0
0-90	72 7

Unit Tested	**ASYM-A-LYTE™ I-30-120**
Description	WIDE SPREAD WAREHOUSE ASYMMETRIC LIGHT OUTPUT
Lamp Position	HORIZONTAL A ACROSS MAIN LUMINAIRE AXIS B ALONG MAIN LUMINAIRE AXIS
Lamp	HIGH PRESSURE SODIUM—CLEAR
Lumens	50 000
Watts	400
Bulb	E 18
Test Distance	8 METERS
Test No	79
Tested By	LIGHTING SCIENCES INC
Date	MARCH 23 1981
Approved By	

Figure 3

When translated to a high pressure sodium lamp with the necessary hardware alterations, again an asymmetric distribution of light results as shown in Fig. 3.

Through the use of appropriate, computer generated, vertical illumination, footcandle computations for a variety of stack heights, aisle widths and luminaire spacings, a number can be determined which characterizes the maximum allowable spacing to mounting height ratio for a given photometric fixture light distribution.

Conventionally referred to as "Spacing Ratio", this number is the single most useful index for use of a warehouse unit.

In both photometric curves shown above, this "spacing ratio" number is "3".

This can be graphically illustrated by the observation of Fig. 4, which is a top view of units in a warehouse aisle, units using conventional industrial highbay light distributions, in comparision to Fig. 5 showing the result of asymmetric light output equipment.

The only caution to be exercised is that the orientation of luminaire in relation to the aisle, is now important and must be as shown in Fig. 6.

TRADE-OFFS:

While this entire discussion has focused on vertical illumination, so far, it's reassuring to realize that horizontal illumination on the floor of the aisle is always uniform and more than adequate whenever vertical illumination is uniform and adequate. Innumerable calculations have born this out, so that unless floor illumination is particularly critical, it is generally not necessary to calculate it.

Low pressure sodium is advisable whenever color recognition is not a necessary part of the seeing task, since L.P.S. is a monochromatic source and renders the visual field in black and white.

The advantages of L.P.S. are simply that it is substantially (up to 50%) more efficient on a lumens per watt basis than high pressure sodium --- and hence, lower energy use and operating costs result.

Also, since L.P.S. is much larger a source, as seen in Fig. 7, the brightness of source and fixture is considerably reduced. Such units are, therefore, substantially more comfortable to the eye of the warehouse operating crew.

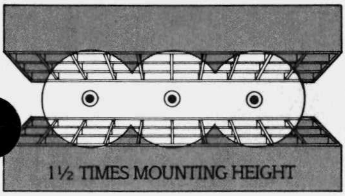


Figure 4

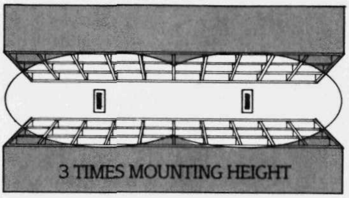


Figure 5

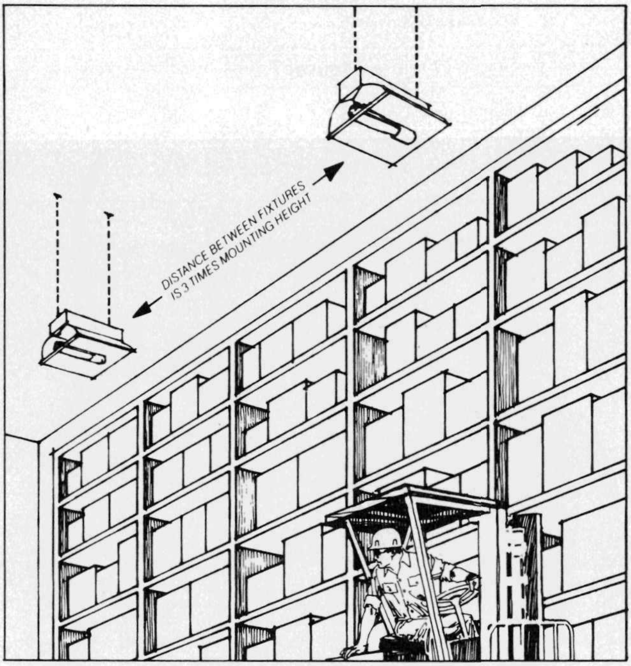


Figure 6

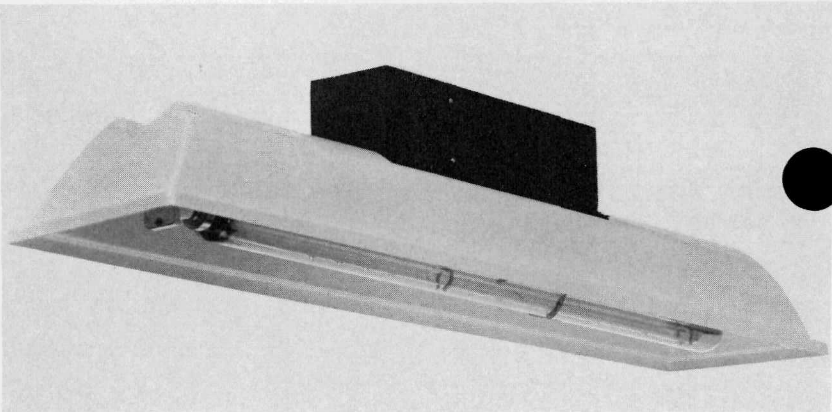


Figure 7

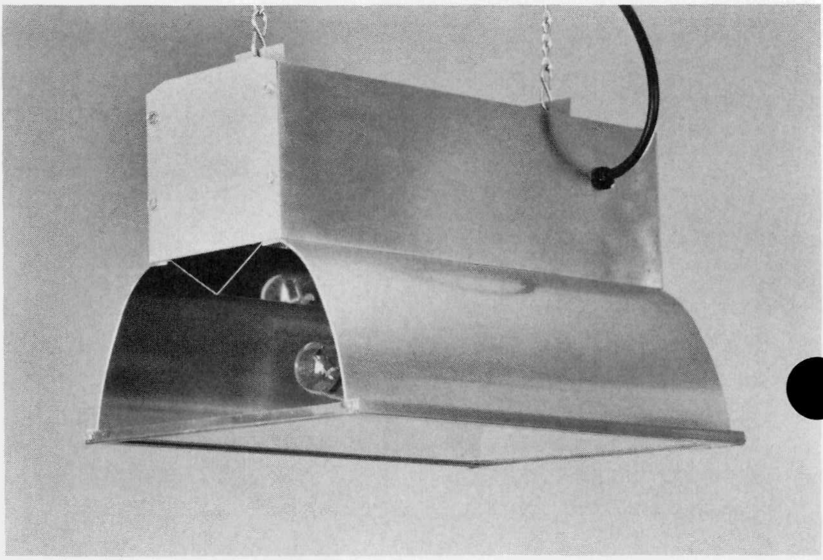


Figure 8

QUANTITATIVELY, THIS CAN BE EXPRESSED BY AN ARC SOURCE BRIGHTNESS OF APPROXIMATELY 375 LUMENS PER INCH OF ARC.

THE ADVANTAGE OF H.P.S. IS PRIMARILY THAT AS A VERY EFFICIENT SOURCE OF LIGHT IT ALSO PROVIDES A SUFFICIENTLY BROAD SPECTRUM OF FREQUENCIES TO ALLOW THE RECOGNITION OF MOST COLORS. THIS LITTLE COMPROMISE WITH COLOR RENDITION NEEDS TO BE MADE.

SINCE THE H.P.S. LAMP PROVIDES ITS POWERFUL ILLUMINATION FROM A SMALL ARC, AS SEEN IN FIG. 8, A CONSIDERABLY BRIGHTER SOURCE MUST BE ACCEPTED.

QUANTITATIVELY, APPROXIMATELY 8700 LUMENS PER INCH OF ARC ARE INVOLVED HERE.

FURTHER TRADE-OFF CONSIDERATIONS THAT CAN BE FACTORED INTO THE DECISION-MAKING PROCESS OF SELECTING WAREHOUSE LIGHTING ARE:

EXCELLENT COLOR RENDITION CAN BE ACHIEVED WITH THE USE OF CLEAR METAL HALIDE LAMPS IN PLACE OF H.P.S. LAMPS, WITH THE IDENTICAL SPACING RATIO OF "3" BUT WITH REDUCED SYSTEM EFFICIENCY BECAUSE OF THE LAMPS LOWER EFFICACY.

THE ADDITION OF A SMALL PROPORTION OF LUMENS FROM A FLUORESCENT SOURCE, ADDED TO THE L.P.S. IN THE SAME FIXTURE (ABOUT 15%) CAN PROVIDE COLOR RECOGNITION WITH AN L.P.S. SYSTEM AT ONLY A SMALL REDUCTION IN SYSTEM EFFICIENCY AND NO DECREASE IN SPACING RATIO.

SIZES:

L.P.S. SOLUTIONS ARE AVAILABLE IN A VARIETY OF SIZES.

180 WATT LAMP	33,000 LUMENS
135 WATT LAMP	22,500 LUMENS
55 WATT LAMP	8,000 LUMENS
35 WATT LAMP	4,800 LUMENS

H.P.S. SOLUTIONS ARE ALSO AVAILABLE IN A VARIETY OF SIZES.

1000 WATT LAMP	140,000 LUMENS
400 WATT LAMP	50,000 LUMENS
250 WATT S-LAMP	30,000 LUMENS
250 WATT LAMP	27,500 LUMENS

THE CHOICE OF THE LAMP IS GENERALLY DETERMINED BY THE FOOTCANDLE LEVEL DESIRED---SINCE IT IS ADVANTAGEOUS TO USE THE MAXIMUM SPACING AND FEWEST FIXTURES POSSIBLE IN ORDER TO REDUCE CAPITAL INVESTMENT.

Figure 9

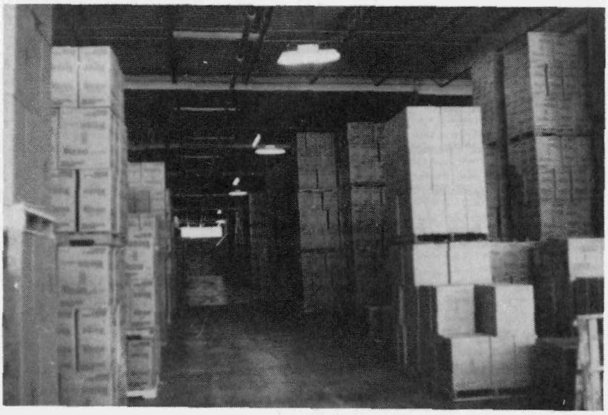


Figure 10

Figure 11

APPLICATIONS:

SYNTEX BEAUTY CARE, INC.
DIVISION OF SYNTEX CORPORATION
NEWBURGH, N.Y.
44-400 WATT H.P.S. UNITS, AS SHOWN IN FIG. 9, REPLACED 239 2 LAMP HIGH OUTPUT FLUORESCENT FIXTURES FOR A POWER SAVING OF $10,769 PER YEAR.

MIDWEST DISTRIBUTION CO.
COLUMBUS, OHIO
PUBLIC WAREHOUSE
USING 180 WATT L.P.S. UNITS TO REDUCE ENERGY USE BY 67%---AS SHOWN IN FIG. 10.

HARMON COLORS, INC.
DIVISION OF MOBAY CHEMICAL CO.
HALEDON, N.J.
SHOWN IN FIG. 11.
EACH 500 WATT INCANDESCENT LAMP WAS REPLACED WITH A 55 WATT L.P.S. UNIT AND LIGHTING LEVELS INCREASED BY 20%.

CONCLUSION:

DO NOT SPACE WAREHOUSE LIGHTING UNITS CLOSER TOGETHER THAN THREE TIMES THEIR MOUNTING HEIGHT, IF YOU WANT TO SAVE MONEY.

DAYLIGHTING ASPECTS OF THE DOE PASSIVE COMMERCIAL BUILDINGS PROGRAM

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SUMMARY

The U.S. Department of Energy is conducting an experimental program to assess the use of passive solar technologies in non-residential buildings. Begun in 1979, this effort has consisted of design, construction and performance evaluation for 23 buildings throughout the country. While the buildings vary in size and type, all designers have developed solutions which use passive techniques to address the lighting, heating and cooling energy requirements and which integrate these passive elements with the conventional building mechanical and electrical systems. A group of ten projects, in which daylighting was a primary element of the design solution, has been selected for analysis in this study.

In previously published technical papers, several aspects of this DOE Program have been discussed (overall program organization, economic analysis, cooling strategies, analytical approaches and lessons learned). The purpose of this paper is to present data regarding the daylighting aspects of ten projects and to address the following topics:

- oo Presentation of physical parameters, primary daylighting features and predicted performance of the projects

- oo Comparison of physical aspects of the building (such as aperture and floor area) to predicted lighting energy savings and total energy savings.

- oo Preliminary measured performance results for lighting energy savings in selected buildings and responses of users to lighting aspects.

PHYSICAL PARAMETERS AND DAYLIGHTING FEATURES

While all projects in the DOE Program make some use of daylighting to save energy, the ten projects shown in Table 1 make daylighting a primary element of the design solution. Table 1 presents the most important physical parameters of these ten projects, the primary daylighting strategies, and the predicted energy requirements.

The definitions used to characterize the primary daylighting strategies are as follows:

- o Lightshelves: A reflective device (usually located near a window) which reflects and disperses sunlight onto ceilings and walls.

- o Clerestory: An upper zone of a wall pierced with a window to admit light or air.

- o Roof Monitor: A raised section of roof with openings, louvers, or windows (not parallel to roof plane) used to admit light or air.

- o Skylight: A glazed roof aperture parallel to the roof.

A dimensionless ratio of the glazed solar aperture area to the building floor area is also shown in Table 1 to allow comparison of projects internally and comparisons to other daylighting studies. This ratio will be referred to in this paper as the "percent aperture." The solar aperture shown represents that glazing which, in the judgment of the authors is primarily included in the design for the purpose of admitting sunlight to save conventional energy rather than for view. Since each project developed an integrated design approach to address heating, cooling and lighting energy requirements, the solar aperture cannot be attributed exclusively to daylighting purposes. The size of the solar aperture was selected by each design team as part of a comprehensive solution to architectural and energy requirements; no attempt was made by designers to optimize the solar aperture area based exclusively on daylighting benefits.

Two of the projects included in this study have sunspaces or atriums as a part of the design. Generally, these features are not incorporated primarily for day-

TABLE 1. DESCRIPTIONS OF TEN BUILDINGS IN PASSIVE COMMERCIAL BUILDING PROGRAM

#	PROJECT NAME	BLDG. TYPE	LOCATION	PRIMARY DAYLIGHT STRATEGIES	BLDG. AREA	GLAZ. AREA / BLDG. AREA	PRE-DICTED LTG. ENERGY RQD (BTU/FT^2-YR)	PRE-DICTED TOTAL ENERGY RQD (BTU/FT^2-YR)
1	Mt. Airy Public	Library	Mt. Airy, NC	Roof Moni-tors/Light shelves	13,450	1,410 / 13,450 = 10.5%	6,443	17,315
2	Community United Methodist	Meeting/ Classrms.	Columbia, MO	Clerestory w/light shelf	5,493	655 / 5,493 = 12%	1,950	6,690
3	Abrams Primary School	Elem. School	Bessemer, AL	Roof Moni-tors & sky lights	26,593	1,920 / 26,593 = 7%	5,170	26,593
4	St. Mary's School	Gym/Audi-torium	Alexan-dria, VA	Roof Moni-tors	8,880	1,420 / 8,880 = 16%	2,470	27,097
5	Princeton Profes-sional Pk	Rental Offices	Prince-ton, NJ	Atrium and windows w/ light shelves	64,000	8,965 / 64,000 = 14%[1]	4,665	14,898
6	Security State Bank	Bank	Wells, MN	Clerestory	11,012	1,840 / 11,012 = 17%	2,420	28,577
7	Kieffer Store	Retail/ Office	Wausau, Wisc.	Roof Moni-tor, light shelf and sunspace	3,212	373 / 3,212 = 12%[2]	4,844	23,251

[1] For calculating glazing sq. ft. used for daylighting, half of atrium was used.
[2] For calculating glazing sq. ft. used for daylighting, half of sunspace aperture was used.

TABLE 1. (CONT.) DESCRIPTIONS OF TEN BUILDINGS IN PASSIVE COMMERCIAL BUILDINGS PROGRAM

#	PROJECT NAME	BLDG. TYPE	LOCATION	PRIMARY DAYLIGHT STRATEGIES	BLDG. AREA	GLAZ. AREA / BLDG. AREA	PRE-DICTED LTG. ENERGY RQD (BTU/FT^2-YR)	PRE-DICTED TOTAL ENERGY RQD (BTU/FT^2-YR)
8	Walker Field	Airport Terminal	Grand Junction, Colo.	Roof Monitors	66,700	$\frac{3,380}{66,700}$ = 5%	8,125	42,187
9	Johnson Controls Branch Office	Office/ Warehouse	Salt Lake City, Utah	Light Shelves/ Roof Monitors	15,000	$\frac{1,487}{15,000}$ = 10%	5,350	40,000
10	Twin Rivers School	Elem. School	Fairbanks, Alaska	Windows w/ light shelves	736 (Class-room only)	$\frac{130}{736}$ = 17.7%	5,322	44,094

lighting purposes, although some of the atrium or sunspace glazing does have daylighting benefits. For purposes of calculating the percent aperture in these projects, half of the atrium glazing was included when comparing to the predicted lighting energy requirements; the full glazing area was included when comparing to the predicted total energy requirements.

Table 1 also shows the predicted lighting energy requirements and predicted total energy requirements (heating, cooling, lighting, service hot water and miscellaneous), expressed in BTU/square foot of building floor area/year. These predictions have been made by each design team based upon average climatic data and the best available information regarding the intended schedule for use of the facility.

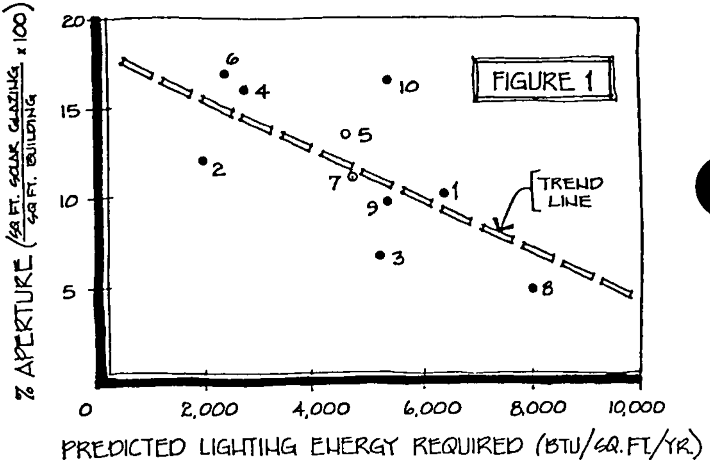
COMPARISON OF PERCENT APERTURE TO ENERGY REQUIREMENTS

The projects included in this study are insufficient in number to make statistical correlations regarding solar features and energy requirements. Nevertheless, observations can be made regarding the trends exhibited by these projects.

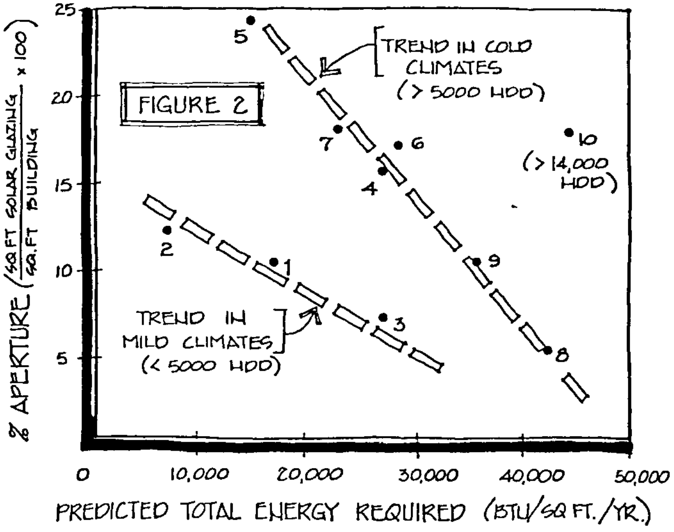
Figure 1 is a comparison of the percent aperture to the predicted lighting energy requirement. Although substantial scatter is apparent, there is a trend which indicates a decrease in the requirement for auxiliary lighting energy as the amount of glazing increases (relative to floor area). This appears to occur without respect to building size, type or location.

Figure 2 is a comparison of the precent aperture to the predicted total energy required for heating, cooling, lighting, service hot water and miscellaneous uses. In this figure there are two trends apparent based on climatic characteristics. In mild climates (heating degree days $<$5,000; base 65 F), total energy requirements decrease with increasing percent aperture; in colder climates (HDD $>$5,000; base 65 F) the decrease of total energy requirements occurs more rapidly with increasing percent aperture. Project #10, constructed in a severe heating climate ($>$14,000 heating degree days; base 65 F) falls outside of either trend.

One project, St. Mary's School gymnasium (#4) exhibits a higher percentage aperture to achieve comparable energy performance than others in its climate group. (The project is located in Alexandria, Virginia, about 5,000 heating degree days). This may be attributable to the fact that this project makes use of roof monitors to provide daylighting in a high (3 story) gymnasium space; this results in a requirement for a large aperture area to provide sufficient daylight levels at the building floor.



o - PROJECTS WITH ATRIUM OR SUNSPACE (½ OF ATRIUM/SUNSPACE GLAZING IS CALCULATED FOR DAYLIGHTING)



PRELIMINARY PERFORMANCE RESULTS

Each of the projects constructed in this DOE experimental buildings program will have at least one year of performance evaluation to determine, at a minimum, (1) the building auxiliary energy requirements for each end use (heating, cooling, lighting, etc.), and (2) the response of building occupants to the working environment of these solar buildings. Although the performance evaluation for most projects is incomplete, three of the projects in this study have preliminary results from partial data.

The store in Wausau, Wisconsin consumed an average of 400 Btu/square foot per month for lighting during the period October 1981 through May 1982. This represents a 35% reduction from the predicted lighting energy use level of 635 Btu/month and, assuming conservatively a 40 hour per week schedule, represents an average lighting level of 0.7 watts per square foot.

The passive solar addition to the Community United Methodist Church in Columbia, Missouri consumed an average of 135 Btu/square foot per month for lighting from November 1981 through May 1982. This is an extremely low lighting energy use figure, but the building is used only intermittently during the week so it cannot be compared directly to the Wausau, Wisconsin store.

Five months of preliminary data from the bank building project in Wells, Minnesota indicates that lighting has consumed 210 Btu/square foot per month. Since the building was occupied over 200 hours each month during this period, the average lighting level was 0.31 w./square foot. This 6% less than predicted lighting energy consumption. The very low light level was achieved despite a tendency for occupants to override the automatic controls for ambient lighting and to leave task lights on all day long.

CONCLUSIONS

Overall, the projects involved in the DOE Passive Commercial Buildings Program total approximately 450,000 square feet and are expected to utilize approximately 50% less energy than conventional designs based upon calculations performed by the design teams. Performance evaluation of the constructed buildings is in the initial phase for most projects, but preliminary results indicate that, once building operations have been stabilized, the buildings in general are capable of performing at the energy levels anticipated by the designers.

While insufficient data exist to do valid statistical correlation, the projects in the DOE Program exhibit trends which are worthy of note:

1) A decrease in the amount of auxiliary lighting energy requirements occurs with an increase in the percent aperture; this appears to occur without regard to building size or location.

2) The amount of total auxiliary energy required decreases with an increase in percent aperture; the trends appear to be highly climate dependent. Buildings in cold climates have a greater perc aperture to achieve energy performance compara to buildings in less severe climates.

ACKNOWLEDGEMENT

N. Scott Jones, Howard C. Huang and Peter G. Rockwell of Burt Hill Kosar Rittelmann Associates assisted greatly in the data analysis and concept generation of this technical paper.

This paper was previously given at the 1983 International Daylighting Conference, 16-18 February 1983, Phoenix, Arizona.

LIGHTWEIGHT RECHARGEABLE BATTERIES USING POLYACETYLENE, $(CH)_x$ AS THE CATHODE-AND/OR ANODE-ACTIVE MATERIAL

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Polyacetylene, $(CH)_x$, is the simplest possible conjugated organic polymer. It can be prepared in the form of silvery, polycrystalline, flexible films whose conductivity we have found can be readily increased by ca. twelve orders of magnitude by controlled chemical or electrochemical oxidation, "p-doping", or reduction, "n-doping", to give flexible, lustrous films of "organic metals" conducting in the metallic regime (ca. < 10^3 ohm^{-1} cm^{-1}) (2,3). The present discussion is limited to a description of the use of $(CH)_x$ films as electrode-active materials in three different types of rechargeable battery cells.

(1) ELECTROCHEMICAL CHARACTERISTICS OF THE $(CH^{+y})_x$ ELECTRODE

A cell was constructed from cis-polyacetylene film (thickness 0.1mm; ~3.5mg/cm^2) and lithium metal immersed in an electrolyte of 1.0M $LiClO_4$ in propylene carbonate (P.C.)(3). The charging process in which the $(CH)_x$ is oxidized and the Li^+ is reduced is:

$$\text{Anode Reaction:} \quad (CH)_x \longrightarrow (CH^{+y}) + xye^- \quad (1)$$

$$\text{Cathode Reaction:} \quad xyLi^+ + xye^- \rightarrow xyLi \quad (2)$$

resulting in the net charge reaction

$$(CH)_x + xyLi^+(ClO)_4^- \rightarrow [CH^{+y}(ClO_4)_y^-] + xyLi \quad (3)$$

where $y < 0.07$. Reversal of the above reaction may be obtained on discharging at a fixed applied potential of 2.5V, the potential (vs. Li) of parent, unoxidized $(CH)_x$ in this electrolyte.

Significant oxidation of $(CH)_x$ occurs only at an applied potential greater than 3.1V. After the onset of oxidation, the open circuit voltage, V_{oc}, rises rapidly with increasing oxidation up to oxidation levels of ~ 1% and then increases more slowly. The relationship between cell potential and degree of oxidation under various conditions has been studied at oxidation levels up to 6.0%. Diffusion of $(ClO_4)^-$ ions from the exterior to the interior of a 200Å $(CH)_x$ fibril following a charge cycle causes the V_{oc} to fall on standing. Conversely, after a partial discharge cycle, the V_{oc} rises as $(ClO_4)^-$ ions diffuse from the interior to the exterior of a fibril.

Coulombic efficiencies, $(Q_{discharge}/Q_{charge})100$ where Q_{charge} refers to the total coulombs involved in a given charge process and $Q_{discharge}$ refers to the total coulombs involved in a discharge process to 2.5V, have been determined for several different levels of oxidation. Corresponding energy efficiencies have also been measured. They are (oxidation, coulombic efficiency, energy efficiency): 1.54%, 100.0%, 80.8%; 2.01%, 99.2%, 79.7%; 2.17%, 100.1%, 81.5%; 2.51%, 95.8%, 78.2%; 4.0%, 89.5%, 72.8%; 6.0%, 85.7%, 68.2%.

Studies have been made of the change in voltage during constant current discharges of a 7.0% oxidized film at 0.1mA (19.5A/kg), 0.55mA (107A/Kg) and 1.0mA (195A/Kg). Values in parentheses refer to the discharge current normalized per Kg of $[CH(ClO_4)_{0.07}]_x$ employed. The corresponding energy density values upon discharge to 2.5V and 3.0V, between which potentials the voltage begins to drop rapidly are 255Whr/Kg and 217Whr/Kg, respectively. The energy density values are based only on the mass of the electroactive material involved and are calculated using the weight of the $[CH(ClO_4)_{0.07}]_x$ employed and the weight of Li consumed in the discharge reaction (the reverse reaction to that given by equation (3) for the charging reaction). The average power densities for the 0.1mA, 0.55mA and 1.0mA discharges are 70W/Kg, 354W/Kg and 591W/Kg, respectively.

Maximum power densities were obtained at the beginning of a discharge cycle using an external load whose resistance was matched to the internal resistance of the cell. Values were obtained by measuring V_m and/or I_m (V_m and I_m = voltage and current respectively at the very beginning of a discharge cycle) and R_l (the external load) by use of the relationships $P_{max} = V_m I_m$, $P_{max} = V_m^2/R_l$ and/or $P_{max} = I_m^2 R_l$. The values obtained, ~ 30,000W/Kg, were relatively independent of either the extent of oxidation of the $[CH(ClO_4)_y]_x$ or the absolute weight of the $[CH(ClO_4)_y]_x$ employed.

Polarization studies have also been carried out. The value of the average discharge voltage, $\overline{V}_d$, under different constant current, i_d, discharge conditions has been investigated for polyacetylene oxidation levels of 6.0%, i.e., $[CH^{+0.06}(ClO_4)^-_{0.06}]_x$ and 2.0%, i.e., $CH^{+0.02}(ClO_4)^-_{0.02}]_x$ in cells of the above type. <u>Cis</u>-$(CH)_x$ film (~ 0.1mm in thickness) was used in the construction of the cells. Current densities were calculated on the basis of the area of one side of the $(CH)_x$ film employed. All voltages are given with respect to the Li counter electrode.

The variable parameters studied in the polarization investigations were: (i) the constant current discharge density, j_d (mA/cm^2); (ii) the degree of oxidation of the polyacetylene; (iii) the size of the polyacetylene cathode and (iv) the time between the termination of the charge and the beginning of the discharge portion of a cycle.

For cells employing 6.0% oxidized polyacetylene cathodes, measurements were carried out immediately after charging, on a cell containing a 1.0cm^2 (3.3mg) piece of $(CH)_x$ film. Two different methods were used. For constant current discharges at 10, 8 and 4 mA/cm^2, the cell was discharged until the discharge voltage, V_d, fell to 2.5V. The average discharge voltage, $\overline{V}_d$, was taken as the average of the initial discharge voltage and the final discharge voltage, 2.5V, characteristic of parent, neutral, $(CH)_x$. For discharges at 0.001, 0.005, 0.01. 0.02,and 0.04 mA/cm^2 the average discharge voltages were all obtained in the same experiment. The cell was first discharged at 0.001 mA/cm^2 until the voltage was relatively constant, at which stage the discharge voltage was recorded. This was taken as the average discharge voltage for a discharge current of 0.001 mA/cm^2. The discharge current was then increased to 0.005 mA/cm^2 and when the voltage again became relatively constant, it was recorded. The operation was then repeated at 0.01 , 0.02 and 0.04 mA/cm^2. The error introduced by this procedure is small since the extent to which the cell had been discharged when any given voltage was recorded was small. Moreover, any error introduced by this procedure will actually give poorer results, i.e., a greater variation of $\overline{V}_d$ with increasing i_d than when an experiment is carried out under optimum conditions using a fully charged cell for each different discharge current. The cell was then recharged to the 6.0% level of oxidation and was discharged at 0.08 mA/cm^2 until V_d became relatively constant. It was again recharged to the 6.0% oxidation level and was discharged at 0.4, 0.8, and 1.0 mA/cm^2 in a single experiment as described above. The polarization curve shows how remarkably constant $\overline{V}_d$ is, even when i_d is varied over four orders of magnitude. Thus the value of $\overline{V}_d$ decreases by only ~25% during an increase in discharge current of this order of magnitude. The current densities and power densities corresponding to the above discharge currents may be normalized to 1 Kg using the total weight of the $[CH(ClO_4)_{0.06}]_x$ employed and the weight of the Li consumed in a complete discharge reaction. The values are given in Table 1.

Table I
DISCHARGE CHARACTERISTICS OF PARTIALLY OXIDIZED POLYACETYLENE CATHODES[e]

6% Oxidation			2% Oxidation		
i_d[a] (mA/cm^2)	C.D.[b] (A/Kg)	$\overline{P.D.}_i$[c] (W/Kg)	C.D.[b] (A/Kg)	$\overline{P.D.}_i$[c] (W/Kg)	$\overline{P.D.}_{15hr.}$[d] (W/Kg)
0.001	0.204	0.77	-	-	-
0.1	20.4	74	18.7	65	64
1.0	204	670	187	657	626
2.0	-	-	374	1262	1167
4.0	816	2500	-	-	-
5.0	1020	-	935	2788	2681
10.0	2040	5860	-	-	

a. current density; b. current density per Kg; c. power density (immediate discharge); d. power density (15 hr. delayed discharge); e. for convenience in comparing the 6% and 2% oxidation data, the "C.D." and "$\overline{P.D.}$" values are arbitrarily given to a maximum of 4 significant figures.

For cells employing 2.0% oxidized polyacetylene cathodes, measurements were carried out using a cell containing 4.3 cm^2 (19.7 mg) of $(CH)_x$ film. After charging to 2.0% oxidation level, the cell was immediately discharged at a constant current of 0.43 mA (0.1 mA/cm^2) to 2.5V. The $\overline{V}_d$ value was calculated from the area under the V_d vs. Q curve, (V_dQ), by dividing it by the number of coulombs released in the discharge process. The cell was then discharged at an applied potential of 2.5V for 16 hours and was then again recharged to the 2.0% oxidation level. It was next permitted to stand for 15 hours during which time the V_{oc} fell to 3.54V as partial diffusion equilibration of the $(ClO_4)^-$ ions occurred. The $\overline{V}_d$ was calculated in a similar manner to the previous experiment involving the 2.0% oxidized film and the cell was again discharged at 2.5V for 16 hours before recharging to the 2.0% oxidation level. The entire process involving both the immediate and delayed discharge cycles was repeated for discharges at i_d=4.3mA (1.0mA/cm^2), 8.6mA (2.0mA/cm^2), and 21.5mA (5.0mA/cm^2).

The current densities and average power densities, $\overline{P.D.}$, normalized to 1Kg are given in Table I. It can be seen that the results for the immediate discharges of the cell with 6.0% oxidized film and the cell with 2.0% oxidized film are almost identical even though their degree of oxidation differs so greatly and that the weights of the films employed varied by more than a factor of six. The average power density values, $\overline{P.D.}$, (the product of the $\overline{V}_d$ and the i_d for a given experiment) are slightly smaller for the discharges carried out after a 15 hour waiting time since in each case their $\overline{V}_d$ values are ~ 0.15V lower than the values obtained in the immediate discharges. Nevertheless, it was found that the $\overline{V}_d$ values parallel those of the immediate discharges and change relatively little over a fifty-fold increase in discharge current viz., 3.50V at 0.43mA (0.1mA/cm^2) and 2.86V at 21.5 mA (5.0mA/cm^2). It should be noted that the average power densities for a given constant current discharge value are large and are relatively independent of either the degree of oxidation of the polyacetylene or of the mass of polyacetylene used in a cell.

The polarization curves obtained are similar to the published polarization curve (at constant load) for the $SOCl_2$/Li primary cell in which current densities are based on the area of one side of the cathode (4). It may be concluded that cells of the type used in this investigation undergo relatively little polarization while delivering a major portion of their stored energy at high discharge rates even after dopant diffusion into the fibrils has been allowed to occur.

(2)ELECTROCHEMICAL CHARACTERISTICS OF THE $(CH^{-y})_x$ ELECTRODE

Selected electrochemical characteristics of a cell constructed from cis-polyacetylene film (thickness ~ 0.1mm; ~ 3.5mg/cm^2) and lithium metal immersed in an electrolyte of 1.0M $LiClO_4$ in tetrahydrofuran (THF) have been studied. A spontaneous electrochemical reaction occurs when the $(CH)_x$ and Li electrodes are connected by a wire external to the cell. The Li is oxidized and the $(CH)_x$ is reduced during the process according to the reactions given below:

Anode Reaction: $xyLi \rightarrow xyLi^+ + xye^-$ (4)

Cathode Reaction: $(CH)_x + xye^- \rightarrow (CH^{-y})_x$ (5)

giving the overall net reaction

$$xyLi + (CH)_x \rightarrow Li_y^+(CH^{-y})_x \qquad (6)$$

where y < ~ 0.1. It should be noted that the reaction given by equation (6) is the discharge reaction of a voltaic cell and that the cell, in its completely charged state consists of parent, neutral $(CH)_x$ which appears to be stable indefinitely in the electrolyte. Reversal of the reaction given by equation (6) may be obtained on charging at a fixed applied potential of 2.5V, the potential (vs. Li) of the parent, neutral $(CH)_x$ in this electrolyte.

Although reduction occurs spontaneously, most studies were carried out at constant applied potentials at various selected values in order to study the system in a controllable manner. Significant reduction of the $(CH)_x$ occurs only at an applied potential less than 1.7V. After the onset of reduction, the open circuit voltage, V_{oc}, falls rapidly with increasing reduction up to a reduction level of ~ 1% and then decreases more slowly.

The relationship between cell potential and degree of reduction has been studied up to 10% reduction levels. The reduction process was stopped at intervals and the V_{oc} value (vs. Li) was measured immediately. The cell was then allowed to stand for a period of 24 hours in order to permit partial equilibration of the Li^+ ions within the 200Å $(CH)_x$ fibrils. The V_{oc} values were again recorded. An increase in potential was observed on standing. This is caused by a decrease in the degree of reduction of the outside of the (CH^{-y}) fibrils as the counter Li^+ ions diffuse towards the center of a fibril together with their attendant negative charge on the polyacetylene. Exactly the opposite effect is observed after a partial electrochemical oxidation (charge reaction) of $(CH^{-y})_x$ to a less reduced state. In this case, the V_{oc} falls on standing.

Coulombic efficiencies, $(Q_{charge}/Q_{discharge})100$ where $Q_{discharge}$ refers to the total coulombs involved in a given discharge (reduction) process and Q_{charge} refers to the total coulombs involved in a charge (oxidation) process to 2.5V have been determined for several different levels of reduction. Values of ~ 99% were found up to 6.0% reduction levels. Somewhat smaller values were found at higher levels of reduction. These high coulombic efficiencies are undoubtedly related, at least in part, to the excellent chemical stability of the partially reduced polyacetylene in the electrolyte. For example, preliminary studies show that the potential of a 4% reduced polyacetylene electrode remained constant at a V_{oc} of 1.2V for four weeks.

Studies have been made of the change in voltage during constant current dischargs of 0.1mA (19.8Amps/Kg), 0.5mA (98.8Amps/Kg) and 1.0mA (197.6Amps/Kg) to 6% reduction of the $(CH)_x$, i.e. to a composition of $[Li^+_{0.06}(CH)^-_{0.06}]_x$ in each case. The weight of the $(CH)_x$ employed (4.9mg) and the weight of the Li consumed in the discharge reaction were used to calculate the normalized discharge rates in Amps/Kg given above. Even though each constant current discharge involved the same number of coulombs and hence resulted in the same average percent reduction, the final discharge voltage, V_d, decreased as the discharge currents increased, e.g., V_d=0.62V at 0.1mA, V_d=0.52V at 0.5mA and V_d=0.34V at 1.0mA. This is due to the fact that the diffusion equilibrium involving migration of the Li^+ ions from the exterior to the interior of the $(CH)_x$ fibrils becomes less complete the more rapidly the electrochemical reduction process is carried out.

The energy density and average power density values obtained in each of the above discharges are, respectively, 0.1mA, 137.0 Watt hr/Kg and 22.6 Watts/Kg; 0.5mA, 124.6 Watt hr/Kg and 102.7 Watts/Kg; 1.0mA, 116.8 Watt hr/Kg and 192.3 Watts/Kg.

Maximum power density of a cell using 4.5 cm^2 (~ 15mg) of $(CH)_x$ film was obtained by discharging it through an external resistor having the same resistance as the internal resistance of the cell (~ 15 ohms). Measurement of the initial current (54mA) gave a maximum power density of ~ 2,900 Watts/Kg using the relationship $P_{max} = I_m^2 R_l$ where I_m=current at the beginning of the discharge and

R_1=the value of the external load (resistor).
After 1 minute the current was 45mA, after 2.5 minutes it was 24mA and after 5 minutes it had fallen to 14mA.

(3) ELECTROCHEMICAL CHARACTERISTICS OF THE $(CH^{-y})_x/(CH)_x$ CELL

Since both neutral and reduced $(CH)_x$ have good stability in an electrolyte of 1M $LiClO_4$ in tetrahydrofuran a voltaic cell was constructed using $(CH)_x$ as the cathode and $(CH^{-y})_x$ as the anode. During discharge the $(CH^{-y})_x$ gives up an electron to the $(CH)_x$ producing the net overall reaction:

$$[Li_y^+(CH^{-y})]_x + (CH)_x \longrightarrow 2[Li_{y/2}^+(CH^{-y/2})]_x \quad (7)$$

where Li acts as the counter cation to stabilize the polycarbanion species. A cell of this type using 7% electrochemically reduced $(CH)_x$ for the anode and neutral $(CH)_x$ for the cathode has a potential of ~ 1.0V and a short circuit current of ~ $3mA/cm^2$ of $(CH)_x$. The cell shows excellent stability, losing only 0.02V during four to five months. It is fully rechargeable with coulombic efficiencies >99%. It is the first stable, rechargeable battery developed in which both the cathode and anode active materials are organic polymers.

These studies indicate that cells involving neutral and/or partly reduced polyacetylene have excellent stability and exhibit interestingly large energy and power densities even at relatively small levels of reduction of the polyacetylene. The electrochemical characteristics of all the $(CH)_x$ cells are extremely sensitive to the method of cell construction, presence of impurities (especially oxygen), relative ratio of electrolyte to $(CH)_x$, method of charging, etc.

The results obtained in this investigation suggest that electrochemical studies not only of $(CH)_x$ but also of other conducting polymers represent an extensive area for further research not only of fundamental scientific interest but also of possible potential technological value.

ACKNOWLEDGEMENTS

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PROGRESS IN CRYOCOOLER TECHNOLOGY AND ENERGY APPLICATIONS

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ABSTRACT

Although some superconducting devices are now used commercially, the major obstacle to the widespread use of superconducting technology is the requirement for expensive and inconvenient refrigeration systems. We have made significant progress toward the development of a small, low-power, Stirling-cycle cryocooler capable of cooling small devices to superconducting temperatures. The primary limitation on the low temperature performance of Stirling cycle cryocoolers is the lack of proper regeneration of the working fluid at low temperatures. We have experimented with several innovative techniques for improving the low-temperature regeneration of our cooler, and the results of those experiments are discussed. Unprecedented temperatures less than 6K in a magnetically clean system have been achieved, well within the required operating range for SQUID devices. We expect that the availability of convenient, low-cost cryocoolers will rapidly introduce superconducting technology into a wide range of scientific and commercial applications. Some of these potential applications are discussed.

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INTRODUCTION

The goal of our program has been to develop a mechanical refrigerator (cryocooler) suitable for operating superconducting instrumentation near 5 Kelvin (-268°C or -450°F) without the requirement for liquid helium cooling or complicated, unreliable, and expensive cooling devices. The most important application of this is magnetic sensing with SQUID devices which requires the cryocooler to have a low magnetic signature and needs very low cooling powers. This also implies very low input power requirements. Present commercial cryocoolers have a built-in temperature limitation of about 10K and are built from metallic and magnetic materials. This temperature limitation is due to the decreasing heat capacity of the regenerating material and the increasing density of the helium. The experiments being conducted have examined several novel approaches to improving this regeneration in the coldest stage of a four stage fiberglass crycooler.

CRYOCOOLER APPLICATIONS

The primary use for a low temperature nonmagnetic cryocooler is for the operation of SQUID devices used as magnetic sensors. The SQUID is a superconducting device whose output is periodic in magnetic flux. Sensitivities to magnetic field on the order of < 10^{-14}T/ $\sqrt{Hz}$ and energy 10^{-30} J/Hz may easily be obtained with commercial S.H.E. devices. This is several orders of magnitude more sensitive than conventional magnetometers. Besides this, the SQUID is relatively inexpensive and extremely simple to use assuming that one has a source of cold to keep the SQUID superconducting (T < 8K). SQUID magnetometers are regularly used in geophysical prospecting. They directly sense distant magnetic objects and can provide aerial magnetic surveys. They are being used to determine electrical resistivity of the earth as a function of depth (2). This is made possible by correlating the difference in electric field measured on the earth's surface with the SQUID determined magnetic field. This can give a model independent resistivity down to tens of kilometers. Another prospecting method is to use an alternating magnetic field and remotely sense its effect. This controlled electromagnetic source is usually on the surface, but could be in a separate aircraft or in an adjacent borehole. Likewise magnetic materials could be injected into one borehole and sensed in other locations. A self contained cryocooler would be ideal for borehole use in that only input electrical power is required and one does not have the problem of exhaust gases from the liquid helium reservoir. Surveys in remote areas would also be helped by not requiring liquid helium supplies. For the same reasons ocean bottom surveying (i.e., nodules, etc.) could be helped by the use of a self contained magnetometer.

Nonmagnetic seismic information has been obtained with superconducting gravimeters (3) which use a levitated superconducting ball. This instrument measures the position of the levitated ball with gravitational influences.

Satellite based sensors, particularly infrared, can be improved by an order of magnitude and certain microwave receivers and mixers can be improved by several orders of magnitude by low temperature cryocoolers (4).

The cryocooler will conserve the usage of helium since presently our supplies are being treated as disposable and are not recoverable after being vented to the atmosphere.

Other applications are biomedical magnetometers (5), superconducting computers, and clean ultra high vacuum helium pumps (low power).

THEORY

The cryocooler being investigated uses for simplicity, a Gifford-McMahon cycle. This cooler applies pressure from a high or a low reservoir at the correct time with respect to the moving displacer to obtain cooling at the far end. The walls of the piston and cylinder supply the needed heat capacity to regenerate the heat between the two temperatures. Valves are used to control the pressure. When the piston has minimum volume at the cold end, the high pressure reservoir is connected to the engine and the displacer moves up at constant pressure regenerating gas from the hot end to the cold end of the engine. Then, when the displacer is at its topmost position (with maximum volume in the cold end), the low pressure reservoir is connected, depressurizing the engine. The displacer then moves down regenerating gas from the cold end to the hot end at constant pressure. At this point the cycle repeats itself. Our engine can easily be converted to a Stirling cycle by removing the valves and using a properly phased compressor piston. The general cryocooler that we are studying is shown in Fig. 1. This cryocooler has 4 different cooling stages that move with a common displacer. The compressor at the top supplies the pressure and the SQUID magnetometer is at the bottom of the displacer. The height of this is about 1.5 m and weighs about 10 Kg. The cooling power for this configuration is given by:

$$\dot{Q} = \frac{\pi}{4} T\beta \, V_D \, \Delta P/\tau$$

where T is the temperature, β is the isobaric expansion coefficient, V_D the displaced volume, ΔP the engine pressure difference, and τ the engine cycle period.

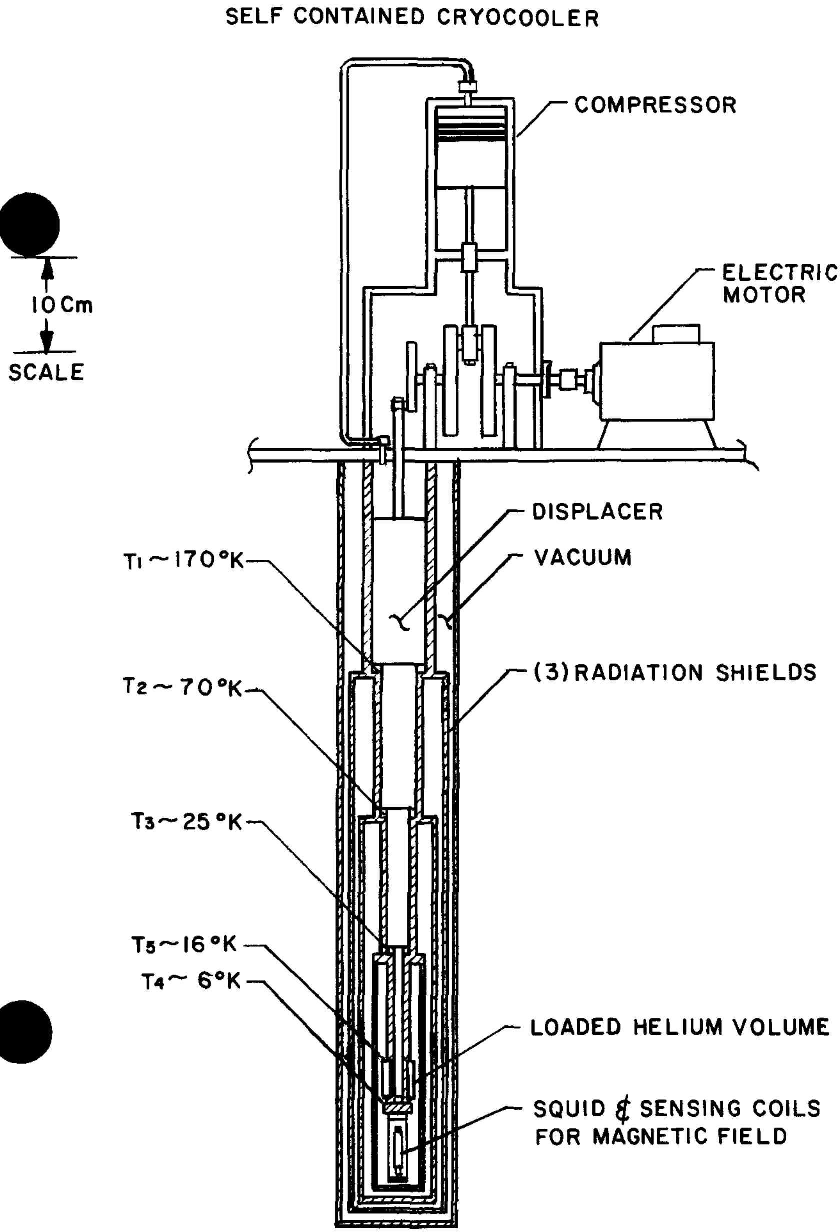

Figure 1. Self contained cryocooler.

The losses involved include conduction, viscous, radiation, shuttle, and most importantly, regenertion loss. The regeneration loss is the largest term at the lowest temperature. This loss has two terms, one of which is due to the finite thermal conductivity of the gap and the other which is due to the ability of the walls to accept heat from the working fluid as it flows through the regenerator. For sinusoidal gas flow, the regeneration loss for a single stage of the cooler operating between temperature T_1 and will be given by:

$$\dot{Q}_R = \left(\frac{17}{280}\right)\left(\frac{d}{\pi DL}\right)(M\dot{n}_o)\left[\int_{T_1}^{T_2}\left(\frac{C_p^2}{K_f}\right)dT + \left(\frac{1.16\sqrt{\tau}}{d}\right)\int_{T_1}^{T_2}\frac{C_p^2}{\sqrt{K_w C_w}}\,dT\right]$$

Here d is width of regenerator gap, D is the displacer diameter, L is the length of the stage, M is the atomic weight of the working fluid (in grams/mole), $\dot{n}_o$ is the molar flow rate along the gap, τ is the period of the cooler cycle, C_w and K_w are respectively the heat capacity and thermal conductivity of the walls, and C_p and K_f are respectively the heat capacity at constant pressure (per gram) and thermal conductivity of the helium working fluid. The integrals account for the variation of C_w, K_w, C_p, and K_f over the temperature gradient, $\nabla_z T$ which is assumed to be constant along the stage. This is shown in Figure 2 for typical cryocooler parameters. This shows that the crossover for refrigeration and losses occurs near 10K unless other steps are taken to increase the heat capacity of the wall of the regenerator. The peaks in refrigeration are due to the critical point of ^4He. The rise in losses is due to the dropping Cp of G-10 fiberglass. Ideally one desires a regenerator of good lateral thermal conductivity to get at a large heat capacity reservoir and very low longitudinal conductivity. Calculated losses for an all G-10 fiberglass machine are shown in Table I. The displacer lengths are about 16 cm and the regenerating radial gaps are .015, .010, .010 and .002 cm for diameters of 3.4, 2.0, 1.2, and .52 cm for stages 1 to 4 respectively.

Table I. Estimated losses and refrigeration in four stage cooler with the fourth stage a 3 concentric tube G-10 regenerator. All values are given in milliwatts. Stroke = 1.5 cm, Speed = 1.5 sec, P_{hi} = .79MPa, and P_{lo} = .15MPa.

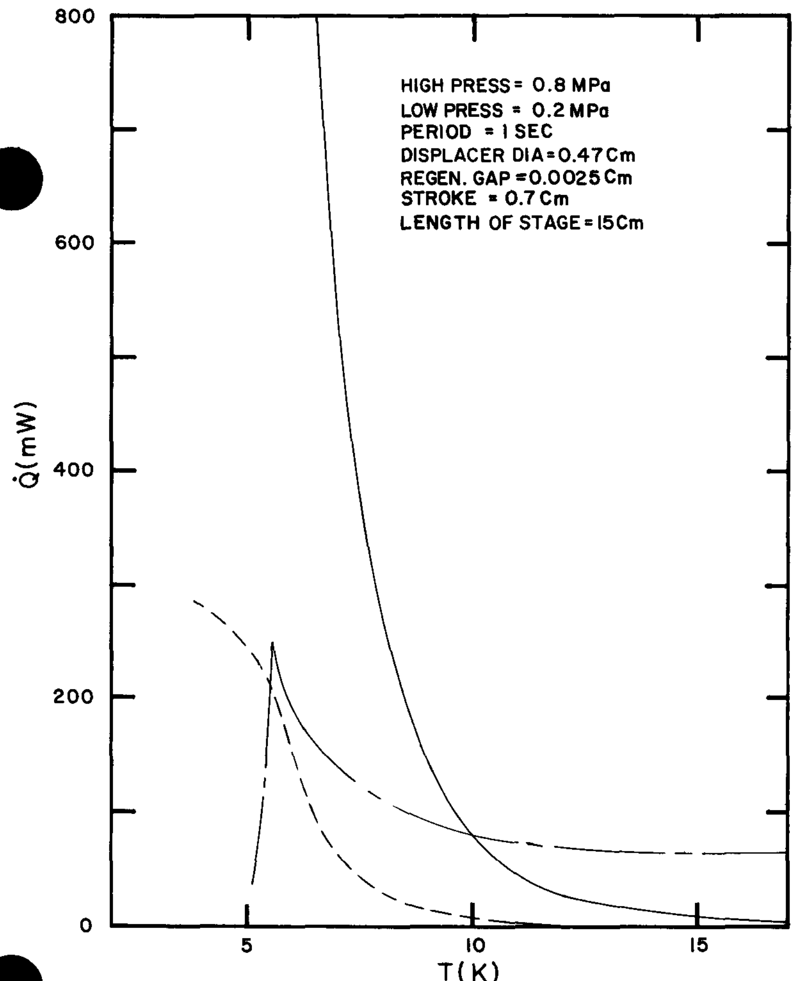

Figure 2. Estimates for regeneration loss and refrigeration for coldest stage of a Stirling-cycle cryocooler. The solid line shows the regeneration loss for operating parameters shown. The broken line (—-—-—) shows the expected refrigeration produced by the stage, and the dashed line (- - -) gives the contribution to the regeneration loss from the finite thermal conductivity of the fluid in the regenerator gap.

Stage	1	2	3	4
Operating Temp (K)	164	68	30	7.6
Regeneration	578	464	286	45
Shuttle	760	179	25	6
Conduction	503	87	10	4
Viscous	97	23	4	2
Radiation	220	7	0	0
Total Losses	2158	760	325	5[illegible]
Total Refrigeration	2210	774	354	15[illegible]

RESULTS

Some of the solutions to this problem of decreasing heat capacity of G-10 and increasing ^4He density that we have tried are shown in Figure 3. Figure 3a shows a static region of helium gas at high pressure surrounding the cryocooler working piston volume. Helium gas is used since its heat capacity is an order of magnitude greater than G-10 fiberglass near 5K and one can use metallic sintered vanes to get contact from the gas inside to outside the tube. This yields an effective heat capacity per unit length much greater than fiberglass alone at our engine periods of τ = 1.5 sec. The vanes have been soldered to 1) a laminated copper to stainless steel stack, 2) to a copper to copper nickel stack, and 3) to a very thin walled copper nickel tube in order to have low longitudinal conduction losses. The copper to stainless steel laminate tested obtained a minimum temperature of 6.9K. This structure was very difficult to fabricate however and always manifested a leak. The tube at the end is typically 5mm diameter and the walls are .5mm thick for the laminate and < .2mm for the CuNi tube. The thin walled CuNi tube structure gave a temperature ~ 7 ½ K.

Another solution must be obtained to overcoming the critical point of ^4He gas (5.2K, .23 MPa). The obvious solution is to use ^3He which has a much lower critical temperature (critical point 3.3K, .12 MPa). When this was tried on the CuNi tube regenerator temperatures < 6K were obtained.

Figure 3b shows a counterflow heat exchanger which requires several check valves and a seal. This counterflow heat exchanger makes use of the heat capacity of the working fluid itself and has an inherent high thermal efficiency. A version of this was experimented with and the circulating flow was obtained but large amounts of friction (~ 300 mW) were yielded by a close tolerance alumina seal. This frictional heating kept the third stage too hot to adequately test this concept.

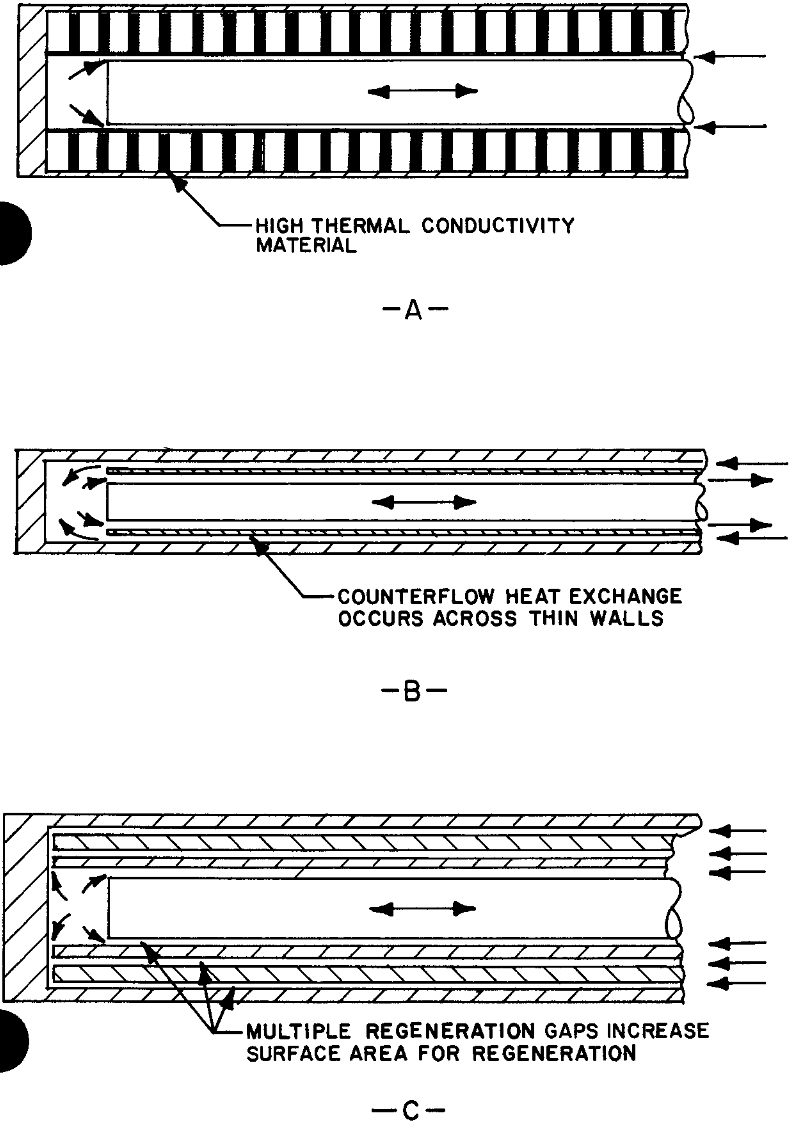

Figure 3. Part (a) shows scheme for loading the final stage of a Stirling cooler with static helium to provide additional heat capacity for regeneration. Part (b) shows counterflow heat exchange mechanism in a Malone cycle, and part (c) shows regeneration gap configuration in first experiments with a 4-stage Stirling cooler.

Table II

Performance of cryocooler tested. $P_{Hi} \sim .79$ MPa, $P_{Lo} \sim .16$ MPa, Stroke = 1 cm, and $\tau = 1.5$ sec. All temperatures are in Kelvin. The gap, L, and D refer to the fourth stage with T_5 located at the top of the helium loaded section.

Type	gap (mm)	L (cm)	D (mm)	T_4	T_5	T_3	T_2	T_1
4 stages Cu to SS	.02	15	5.2	7.1	16.1	26	76	164
G-10 tube	.05	15	5.2	7.8	X	30	68	151
CuNi tube	.02	15	4.3	7.6	16	25	82	177
	.08	15	4.3	8.5	20	26	82	171
	.02	23	4.3	7.6	16	26	75	170
+ ^3He gas	.02	23	4.3	6.0	16	25	75	170
Cu to CuNi	X	X	X	X	X	X	X	X
3 stages only				X	X	12	53	164

Several concentric passages of fiberglass tubes are shown in Fig. 3c. These tubes nested into each other for about 15 cm with a .05mm diametral gap. This construction had problems with alignment which affected its reproducibility but it worked for temperatures ≈ 7.6K.

The solution of the static volume mentioned above has a side effect of stabilizing the temperature of the fourth stage. This is very good since changing the temperature of the SQUID changes its noise level and critical current bias level which results in many orders of magnitude greater noise than possible.

COMMENTS & CONCLUSIONS

Our results to date have provided for the operation of a small nonmagnetic cooler which operates in the temperature range required by superconducting SQUID devices. The many applications of SQUID devices should easily drive the need for such low temperature cryocoolers. Several problems remain such as the requirement for very low pressures, decreasing the diffusion through the cylinder walls, and controlling the tight tolerances required for manufacturing this configuration, but all of these are solvable in time. Our results of temperatures ~ 6K from room temperature for a displacer of only 70 cm long and with very stable temperatures are unique and very encouraging. This represents a major thrust forward towards a self-contained, nonmagnetic, low temperature platform producing the temperatures required for the operation of ultra sensitive devices such as the SQUID. Future work can focus on certain engineering details and noise reduction.

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PHASE CHANGE MATERIALS - STATE OF THE ART

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Energy research has been a very active field for the past few decades and the fruits of this effort are being increasingly integrated into our daily lives. Research in thermal energy storage has been just as active. The emphasis of much of this research has been to develop materials which by the nature of their phase change process, are well suited for storing thermal energy.

This research effort is also bearing fruit, with many commercial phase change materials being used in a number of energy storage applications. Research on phase change materials and systems is still quite active, and should lead to a number of interesting developments.

Rather than projecting the future for PCM's, it is appropriate at this time to consider what we have achieved; to take stock of the energy storage systems now available due to the the research effort over the past few years. To this end, this paper is limited to phase change materials which are presently being used for energy storage, or materials that are developed to the point that they will soon be commercially available.

The phase change materials which have been developed for energy storage from the vast number of potential products have a number of important similarities. They all have the following basic properties.

1. Both phases are condensed, either solids or liquids.

2. The temperature of phase change is "useful" in an energy storage application, typically 0°C to 200°C.

3. The phase change process can be repeated without loss in storage capacity.

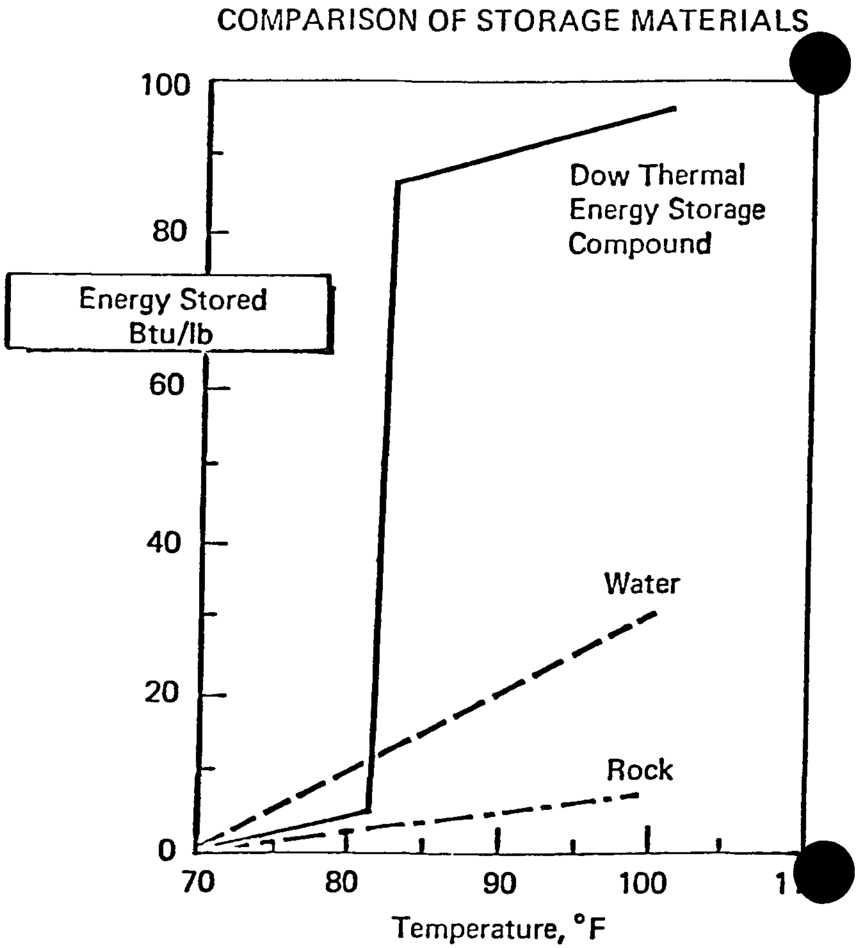
4. The latent energy of the phase change is substantial.

5. The material is not expensive, highly toxic, or noxious.

The fact that PCM's were chosen as the subject for a session at this meeting, attests to their advantages in storing thermal energy. For those of us who have worked in this field for years, that conclusion is without question. For others, it is in order to briefly review the characteristics of phase change materials. Figure 1 illustrates the advantages and limitations of phase change materials. This graph compares the energy storage capacity versus temperature of calcium chloride hexahydrate and the common sensible heat materials, rock and water. This PCM melts at 81°F and stores 82 BTU as latent heat in the melting phase change. This latent heat gives the PCM its key advantage, a greater energy storage capacity. For example, over the temperature range typically used for passive solar heating, 70-90°F, the PCM will store about twenty (20) times the energy of an equal weight of rock or about seven (7) times the energy of an equal volume of water. This advantage of PCM's is the basis for the majority of the energy storage applications, but it is often misunderstood or overstated. The relative capacities of latent versus specific heat materials are dependent on the operating temperature range of the storage subsystem. Correspondingly, the choice of sensible heat or latent heat storage depends on the differences in temperature between the energy available for storage and the energy needed from storage. If this difference is large, i.e. 100°F sensible heat might be a better choice. If the difference is small, i.e. less than 50°F, latent heat is probably the better choice. One exception to these guidelines is when an application needs the other key property of PCM's, its isothermal storage. PCM's store and release energy without a change in temperature. For some applications, this enables energy to be stored and retrieved more efficiently and with simpler controls. As the use of PCM's becomes more commonplace, we are seeing more applications where PCM's are chosen because of this isothermal nature.

The key limitation of PCM's is also evident from this graph. PCM's are only useful at one temperature. 81°F is suitable for some applications, but obviously not all. For this

FIGURE 1


COMPARISON OF STORAGE MATERIALS
100
80
Energy Stored
Btu/lb
60
40
20
0
Dow Thermal
Energy Storage
Compound
Water
Rock
70
80
90
100
Temperature, °F

reason, we need a number of PCM's, with different temperatures to meet the needs of a wide variety of applications.

Due to the efforts of a number of excellent researchers, this variety of PCM's is available. I would be remiss in not recognizing researchers such as Maria Telkes, George Lane of Dow Chemical, and the others who developed these products.

Table 1 contains a list of the key PCM's presently being used or very near commercialization. There are four materials listed, that by themselves, do not fit our category of stable to phase change cycling ($Na_2SO_4 \cdot 10H_2O$, $Na_2SO_4 \cdot 10H_2O/NaCl$, $Na_2SO_4 \cdot 10H_2O/NaCl/NH_4Cl$, and $Na_2S_2O_3 \cdot 5H_2O$). Much work has been done to physically stabilize these products by gelling or otherwise trapping the components in a cross-linked matrix. None of these products are sold directly. Rather, the developers market encapsulated forms of the stabilized system. The remaining products do fit our stability criteria. These products, except for water, are marketed directly as energy storage materials to firms that incorporate them in a variety of applications.

Special attention should be given to the first member of list, water. It is by far the oldest commercial PCM, as the anyone who remembers the days of the iceman can attest. It is however, seldom the basis of comparison for other PCM's. We tend to view Glauber's salt ($Na_2SO_4 \cdot 10H_2O$) as the stereo-type PCM. Yet, many PCM's have properties more akin to water. They undergo a relatively "clean" phase change, without the instability of Glauber's salt and its eutectics. Water is, unfortunately, atypical in one key respect; few materials have as high a latent heat.

This list, which is not inclusive, illustrates the wide range of available PCM's. The products exist, the need is for better methods of encapsulating the products and applying these to the many demands for energy storage.

A state of the art review of PCM's would not be complete without covering the available encapsulated forms of PCM's and some of the applications for which PCM's are being used.

All of the products listed in Table 1 must be contained properly before they are stable. Developing containment for PCM's is at least as difficult, and important, as developing stable PCM's. All of the materials undergo some volume change on phase change. Thus, the container must be capable of containing the resultant repeated flexing. The hydrated salts---favored for their lower price---are quite sensitive

TABLE 1
COMMERCIALLY AVAILABLE PCM'S

PCM	PHYSICAL PROPERTIES		SOURCE OR (KEY RESEARCHER)	COMMENTS
H_2O	0°C (32°F)	80 cal/g	-	
$Na_2SO_4 \cdot 10H_2O/NaCl/NH_4Cl$	13°C (55°F)	(1)	(2)	Incongruent
$CaCl_2 \cdot 6H_2O/CaBr_2 \cdot 6H_2O$	14°C (58°F)	34 cal/g	Dow	
Polyethylene glycol (600 MW)	21°C (70°F)	30 cal/g	Union Carbide, Dow, etc.	
$Na_2SO_4 \cdot 10H_2O/NaCl$	23°C (73°F)	(1)	(2)	Incongruent
$CaCl_2 \cdot 6H_2O$	27°C (81°F)	46 cal/g	Dow (3)	
$Na_2SO_4 \cdot 10H$[illegible]	32°C (89°F)	60 cal/g	(2)	Incongruent

TABLE 1 CONT'D
COMMERCIALLY AVAILABLE PCM'S

PCM	PHYSICAL PROPERTIES		SOURCE OR (KEY RESEARCHER)	COMMENTS
Paraffin Wax	47°C (116°F)	44 cal/g	Sunoco	
$Na_2S_2O_3 \cdot 5H_2O$	48°C (118°F)	50 cal/g	(2)	Semi-congruent
$MgCl_2 \cdot 6H_2O$/ $Mg(NO_3)_2 \cdot 6H_2O$	57°C (135°F)	32 cal/g	Dow	
$Mg(NO_3)_2 \cdot 6H_2O$	89°C (192°F)	39 cal/g	Dow	
$MgCl_2 \cdot 6H_2O$	117°C (243°F)	40 cal/g	Dow	
Polyethylene (cross-linked)	133°C (270°F)	45-50 cal/g	(U. of Dayton, I. Salyer)	Form Stable

(1) Value is dependent on composition and history.

(2) Thermal Energy Storage Composition only available in encapsulated forms.

(3) Chemically modified to be congruently melting.

TABLE 2
COMMERCIALLY AVAILABLE CONTAINED PCM'S

Containment - Air Heat Exchange

Product Type	Temperature °F	Source	Comments
Rigid Plastic Tube	81	PSI, EMI, EECO, Solvay (FR)	
	50, 64, 88,	Calor (UK)	
	70	Sunplace	
	135	EMI	
Rigid Metal Tube	45, 67, 89	Boardman	
	81	Texxor	
Flexible Plastic Film Pouch	73, 86	Colloidal Materials	
	73	Architectural Research	Pouch in polymer concrete panel
Flexible Plastic Film Tube	50, 70, 90	Insolar	

TABLE 2 CONT'D
COMMERCIALLY AVAILABLE CONTAINED PCM'S

Containment - Air Heat Exchange

Product Type	Temperature °F	Source	Comments
Rigid Plastic Panel	81	Solar Components	
	81	Dow	
Rigid Metal Panel	81	Texxor	
Sphere	73, 81, 89, 116	Pennwalt	
	81, 135	Christopia (FR)	

Bulk Containment - Liquid Heat Transfer

Shell & Tube	12, 32, 81, 89, 118, 135	Calmac	
	32	Baltimore Air Coil, and others	
	118	Thermal Energy Storage, Inc.	
Direct Contact	32, 86	OEM Products	

to water content. For these, the container must be an excellent barrier to moisture loss or gain. Similarly, the heat capacity of the polyglycols is degraded by moisture gain and they must be encapsulated in moisture impermeable containers. The glycols and other organics can also degrade from air oxidation and thus should be encapsulated in impermeable materials or be kept away from oxygen, especially when used at elevated temperatures. In addition to these PCM specific requirements, the container must last under exposure conditions and provide for adequate heat transf As evidenced by these requirements, containing of PCM's i not easy. It definitely is not a do-it-yourself undertaking. Proper containment is difficult, but not impossible. Excellent contained PCM's do exist, and some of these products are listed in Table 2.

Table 2 does not list all the available forms of encapsulated PCM's. The field is too rapidly changing for any list to be up-to-date. This list does illustrate that like the PCM's themselves, there are a large number of suitably encapsulated PCM's available.

These products have been used in a wide variety of applications including:

1) Passive Solar Heating, both residential and commercial.

2) Commercial greenhouses - storage of excess daytime heat for nighttime heating.

3) Commercial buildings for the storage of excess daytime heat for nighttime heating, both in conjunction with water source heat pumps and in direct air heat exchange systems.

4. Industrial Energy Recovery for storage of waste heat to supply space heating needs.

5. Air Conditioning - "coolness" storage during off-peak hours for peak cooling loads.

6. Off-peak electricity stored to provide space heating needs.

The applications of phase change materials, this brief li and the many others, reflect some of the strides being m in energy conservation. As we move through this era of energy conscientiousness and get better at what we do, phase change materials will play even more important roles.

ENCAPSULATING PHASE CHANGE MATERIALS - CONCEPT AND APPLICATIONS

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I. Introduction

Widespread use of phase change materials in heat storage applications is contingent upon development of a versatile packaging configuration capable of overcoming such problems as poor heat transfer, pronounced phase separation, possible chemical interaction with environment and cumbersome installation. One concept that offers solution to these problems has recently been developed (1,2). It consists of encasing small PCM tablets in tough polymer materials. Because of high surface area, heat can be transferred in and out of the capsules efficiently. The small capsule size helps prevent phase separation. Since the capsules are self-contained units, the PCM is permanently protected by the wall materials which prevents chemical interaction with the environment.

Capsules of four PCMs useful for active and passive heat storage applications were made and have undergone extensive thermal cycling tests in selected heat exchange fluids and in rigid media such as those used in construction. The four PCMs are a Glauber's salt eutectic mixture (m.p. 71-75°F), $CaCl_2 \cdot 6H_2O$ (m.p. 81°F), Glauber's salt (m.p. 89°F), and paraffin wax (m.p.

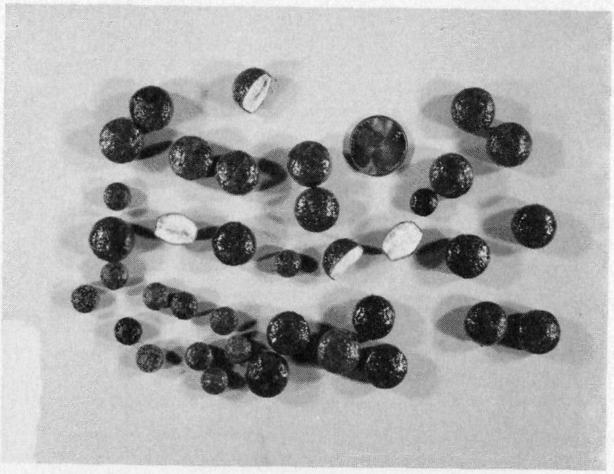


Figure 1. Glauber's Salt Capsules

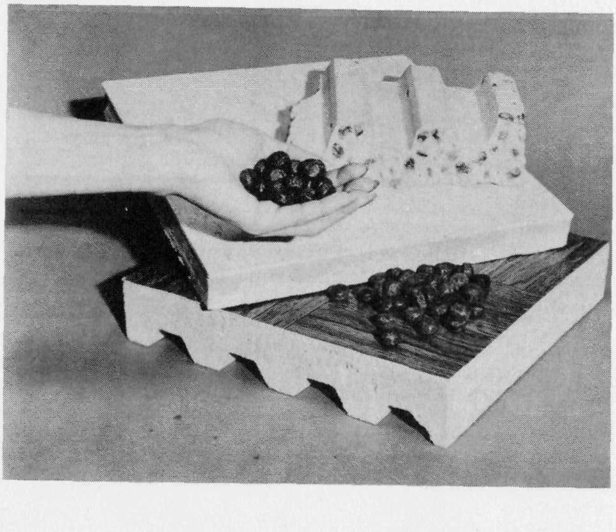


Figure 2. Concrete and Gypsum Blocks Containing Glauber's Salt Capsules

116°F). Test results suggest that these capsules offer new application opportunities in both active and passive systems that are not achievable by conventional PCM package configurations. To this end some new application ideas are proposed.

II. Pelletization and Encapsulation

The geometry and size of the PCM capsules are defined in the pelletization step. Geometry will affect the success of the subsequent encapsulation process, in which excessive edge wear and agglomeration are the problems most frequently encountered. They can be alleviated by eliminating sharp edges and flat surfaces on the starting tablets. Tablets with smooth surfaces and rounded edges were found to have the best geometry.

The manufacturing cost and heat transfer efficiency are both sensitive to the capsule size but in opposite directions. Heat transfer efficiency increases with decreasing size while larger capsules would decrease the manufacturing cost. For practical purposes tablets have been manufactured ranging from 1/4" to 3/4" in diameter.

The PCM tablets were subsequently encased in a tough polymer encapsulant using a roll coater similar to the ones used for sugar coating in the candy and pharmaceutical industries. The wall thickness can be controlled to fit specific application requirements. The standard capsules contain between 15-25% wall materials. Figure 1 shows finished Glauber's salt capsules of various sizes, with some cut open to show a cross section.

III. Thermal Cycling Tests

In order to assess the potential of our PCM capsules in both active and passive applications, they were subjected to thermal cycling in environments simulating application conditions.

A. Thermal Cycling in Selected Heat Exchange Fluids

Ideal heat exchange fluids for the PCM capsules should be compatible with wall materials, nonflammable, and low in cost. In the case of salt hydrates, the fluid should have comparable water vapor pressure. Water and its solutions best fit these criteria.

As expected, wax capsules performed well using water as heat exchange fluid. In the case of the salt hydrates it is necessary to balance the water osmotic pressure on both sides of the capsule walls.

Table 1

Thermal Cycling Tests of Encapsulated PCMs

in Selected Aqueous Fluids

PCM	Heat Exchange Fluids Ethylene Glycol (%)				$CaCl_2$ Solution (%)			No. of Cycles
	0	50	70	75	30	35	40	
Glauber's Salt					X	X		4200
$CaCl_2 \cdot 6H_2O$		X		X				2120
Glauber's Salt Eutectic Mixture		X	X					1900
Wax	X							2800

Solutions of 35-40% $CaCl_2$ and 60-75% ethylene glycol were found to serve well as heat exchange fluids in such PCM capsule compositions.

All four PCMs went through extensive thermal cycling without deterioration. Table 1 summarizes the results in various aqueous heat transfer fluids.

B. Thermal Cycling in Building Materials

One unique feature of these capsules is that they can be embedded in rigid media such as concrete or gypsum without causing chemical interactions between PCM and substrate. In order to evaluate this concept three salt hydrate PCMs were mixed with concrete and gypsum and cast into blocks (see Figure 2). After curing in air the block temperatures were raised above the PCM's melting points. The block containing $CaCl_2 \cdot 6H_2O$ capsules suffered severe cracks at 40°C, while blocks containing Glauber's salt and its eutectic mixture suffered no damage under temperatures as high as 80°C.

Concrete blocks containing capsules of either Glauber's salt or its eutectic mixture were thermally cycled in air between 40° and 120°F along with blocks of plain concrete of similar mass. The blocks containing the PCM capsules showed significant resistance to temperature changes. A temperature profile is shown in Figure 3. When the temperature difference between plain concrete and its PCM containing counterpart is plotted versus temperature of plain concrete, the enclosed area is proportional to the extra heat stored in the PCM (Figure 4). When comparing the enclosed areas on plots from cycle 10 and 270 it is apparent that no deterioration has taken place.

IV. Proposed Application Ideas

These new PCM capsules have potential use in active, passive and hybrid heat storage applications. Some concepts are presented.

A. Active Systems

One implementation could be a storage box of simple design containing PCM capsules through which heat exchange fluid is circulated for charge and discharge of thermal energy. This system is potentially very efficient and low cost. It can be used for solar, waste heat and heat pump storage (Figures 5 and 6).

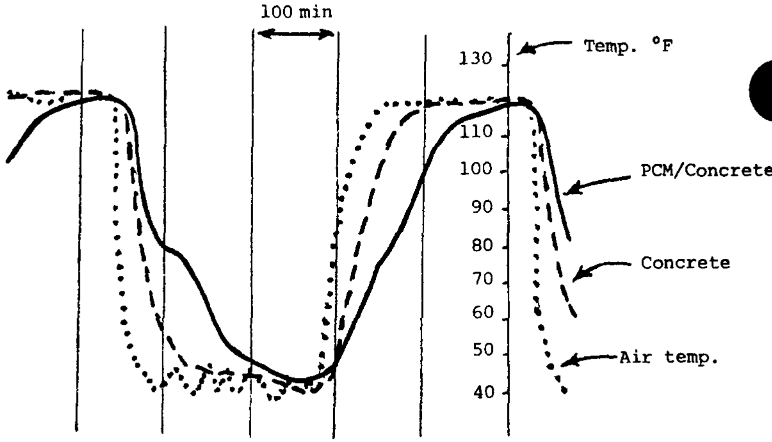


Figure 3. Thermal Cycling Profile of Concrete Block and Block Enhanced With PCM Capsules

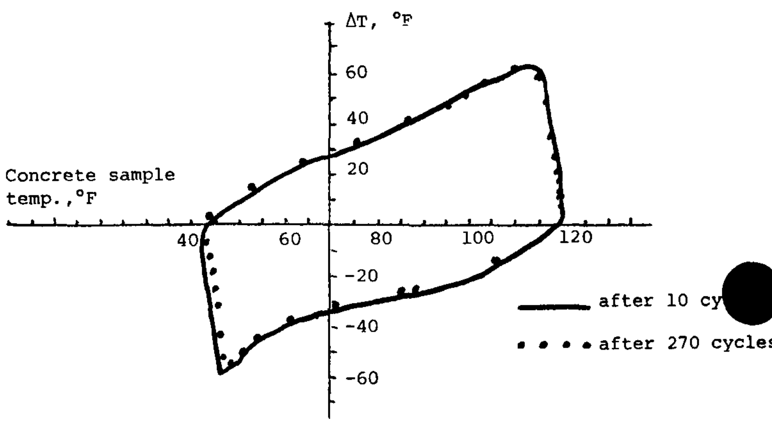


Figure 4. Thermal Cycle Control Temp. vs Temp. Difference

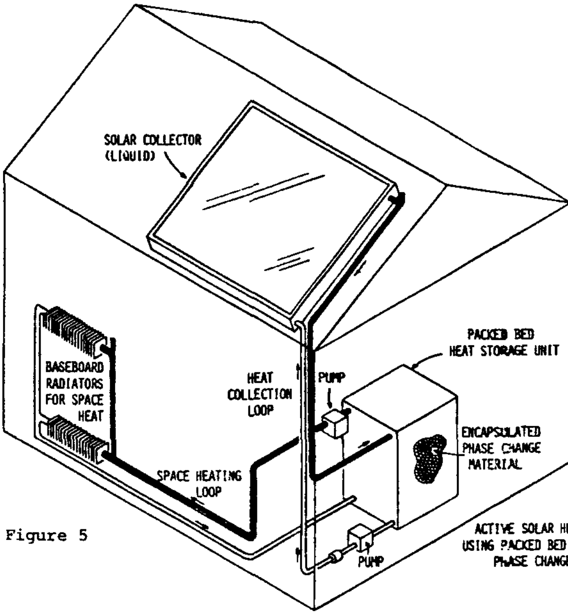


Figure 5

ACTIVE SOLAR HEATING SYSTEM USING PACKED BED OF ENCAPSULATED PHASE CHANGE MATERIAL

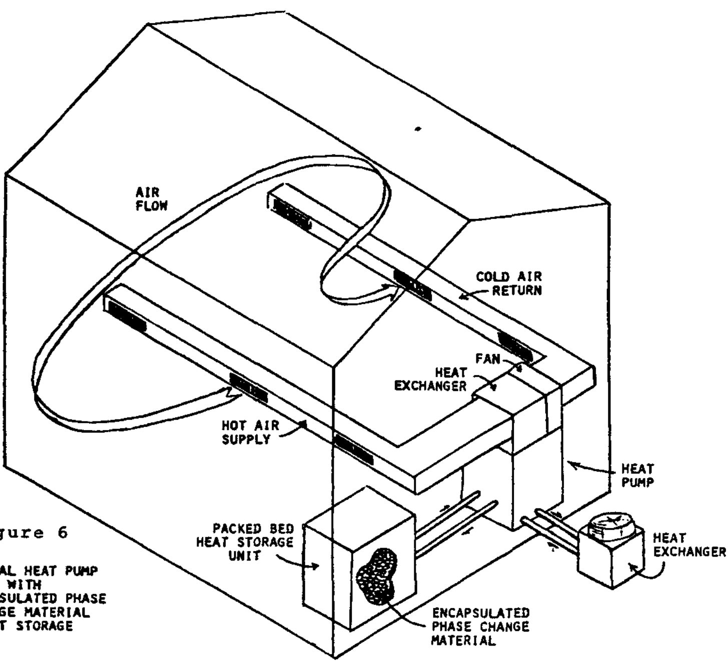
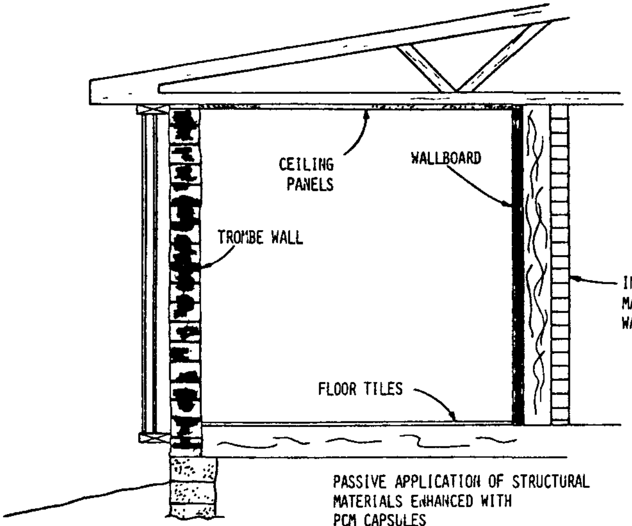


Figure 6

CENTRAL HEAT PUMP WITH ENCAPSULATED PHASE CHANGE MATERIAL HEAT STORAGE



PASSIVE APPLICATION OF STRUCTURAL MATERIALS ENHANCED WITH PCM CAPSULES

Figure 7

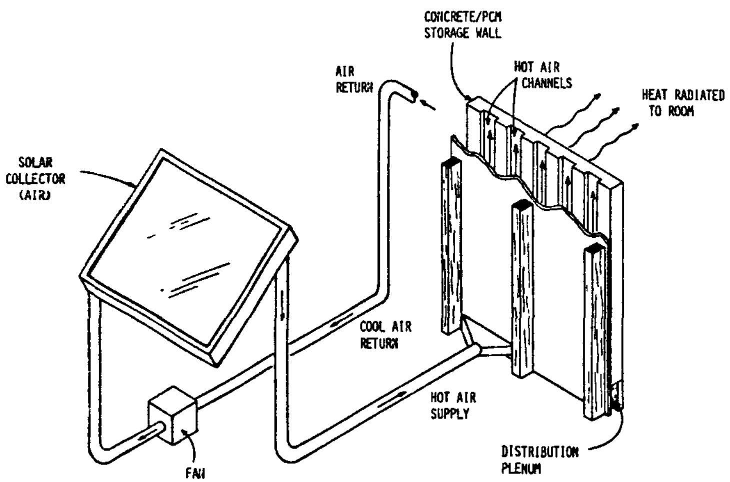


Figure 8

HYBRID
ACTIVE CHARGE - PASSIVE DISCHARGE
SOLAR HEATING
USING PCM ENHANCED CONCRETE WALL
PANELS

B. Passive and Hybrid Systems

Thermal mass of building components such as wallboards, concrete blocks and slabs, floor and ceiling tiles could all be enhanced with PCM capsules. Buildings containing the enhanced components would feature heat storage capacity and be free from often unsightly heat storage boxes, allowing traditional room appearances to be maintained.

With proper design, the components can be custom tailored to fit both passive (Figure 7) and hybrid applications (Figure 8).

V. Conclusions and Recommendations

A novel PCM packaging system suitable for active, passive and hybrid heat storage applications has been developed, which offers for the first time the opportunity of incorporating PCMs in building components. This new packaging system also improves heat exchange efficiency and simplifies system design for active storage unit.

The opportunity of developing downstream heat storage products based on these new PCM capsules is wide open and waits to be explored.

VI. References

1. Johnson Chen, "Pelletization and Roll Encapsulation of Thermal Energy Storage Materials", Proceedings of the 16th Intersociety Energy Conversion Engineering Conference, 931-934 (1981).

2. Johnson Chen and Robert Nelson, "Pelletization and Roll Encapsulation of Phase Change Materials", Proceedings of the Sixth Annual Thermal and Chemical Storage Contractors' Review Meeting, September 14-16, 1981, Washington, D. C., pp. 177-184.

SOLID STATE PHASE CHANGE MATERIALS

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ABSTRACT

Solid state phase change materials (SS PCM's) provide compact thermal energy storage with reduced concern for the containment of the phase change material. Three different kinds of SS PCM which are under laboratory investigation and which show both technical and economic potential are organometallics such as $(n\text{-}C_nH_{2n+1}\ NH_3)_2MnCl_4$, radiation cross-linked polyethylene, and polyalcohols such as pentaerythritol ($C_5H_{12}O_5$). All three of these types of material reversibly absorb thermal energy in the crystalline solid state by an order/disorder transformation. This paper describes the three types of SS PCM and then focuses on the polyalcohols and their possible use in passive solar architectural systems.

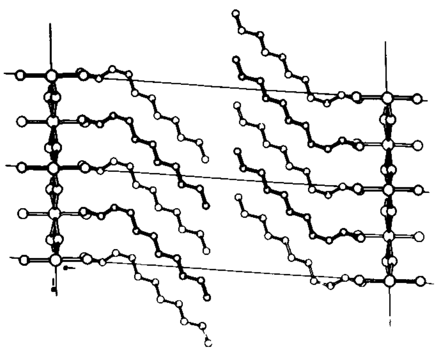
INTRODUCTION

Physical-chemical phase changes such as melting and dehydration reversibly absorb large amounts of thermal energy when the material changes its form (e.g., solid to melt or solid to solution). The change in form requires that these PCM's be housed in some kind of durable and leak-proof container. It would be very desirable to achieve the same large energy storage density in a solid state PCM which did not change its form during the transition and therefore required less secure containment.

Many solids undergo reversible phase changes in the solid state, but very few have sufficiently energetic transformations to be of potential, practical use in thermal energy storage. There are, however, three classes of solid state PCM's which appear to be promising: layer perovskite organometallics, cross-linked polymers, and certain hydrocarbon molecular crystals.

LAYER PEROVSKITES

Certain organometallic compounds with the general formula $(n\text{-}C_nH_{2n+1}NH_3)_2\ MX_4$, where M is a divalent metal ion such as manganese and X is a halogen such as chlorine, exhibit reversible thermal energy absorption in the solid state. The crystal structure of these solids are layered (Figure 1) with interlayer bonding at the metal chloride sites and only weak interaction among the long hydrocarbon chains (1).



1. Schematic diagram of a layer perovskite, $(n\text{-}C_{12}H_{25}NH_3)_2\ MnCl_4$, crystal structure.

At a temperature in the range -3 to 144°C (27-291°F), depending upon the composition, an order-disorder transition occurs in which the hydrocarbon chains lose their regular configuration. The increased disorder involves the reversible absorption of between 10-35 cal g^{-1} (18-63 Btu/lb.) and an increase in volume on the order of 5-10%.

These materials have been dispersed in a polystyrene matrix and found to be mechanically stable in spite of the volumetric changes during transition. While these materials are rather exotic in composition, it has been estimated that they could be mass produced for between \$2.2 - \$4.4/Kg (\$1 - \$2 per pound).

CROSS-LINKED HIGH DENSITY POLYETHYLENE (HDPE)

When pellets of commercial, HDPE are lightly cross-linked with ionizing radiation or with chemical treatment, they become resistant to flow at temperatures above their crystalline melting point. Consequently, the cross-linked HDPE behaves as a solid state phase change material, reversibly absorbing approximately 45-50 cal g^{-1} (81-90 Btu/lb) at 133°C (271°F) (2).

The cross-linking effectively interconnects all of the molecules in a small pellet to form one giant molecule. Theoretical analyses indicate that even a single cross-link per molecule is sufficient to prevent flow of the liquid. Experiments have shown that HDPE can be efficiently and economically cross-linked by use of large industrial electron beam accelerators operating at 3 million volts and depositing a radiation dose of 6-8 megarad. The cost of such treatment has been estimated to be less than \$0.02 per kilogram (\$0.01 per pound) in large scale production, only a small incremental cost above the basic cost of the HDPE pellets which is ∿\$1.14 per kilogram (\$0.52 per pound).

The HDPE has many advantages for thermal energy storage. It is non-toxic, non-volatile and insoluble in typical heat transfer fluids such as ethylene glycol. It appears to be very well suited for direct heat transfer designs in which the heat transfer fluid flows directly over the thermal storage material. The ∿133°C (271°F) phase change temperature is well suited for use with absorption cycle or Rankine cycle air conditioning systems and with some industrial process heating systems.

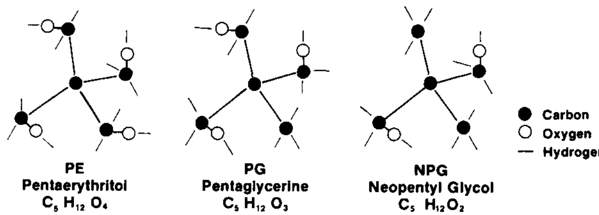
Theoretical considerations suggest that a (specially prepared) highly linear polyethylene could be made and cross-linked to provide form stable pellets with heats of fusion ∿ 55 cal g^{-1} (99 Btu per pound). More research is needed to further develop the potential of this class of SS PCM.

HYDROCARBON MOLECULAR CRYSTALS

Most hydrocarbons form molecular crystals (crystals in which there is only weak attraction between adjacent molecules) and exhibit anomolous thermal behavior in the solid state including reversible transformations which absorb energy. However, most such transformations are not very energetic. Only a few hydrocarbon molecular crystals undergo solid state phase changes with enthalpies of transformation >10 cal g^{-1} (>18 Btu per pound).

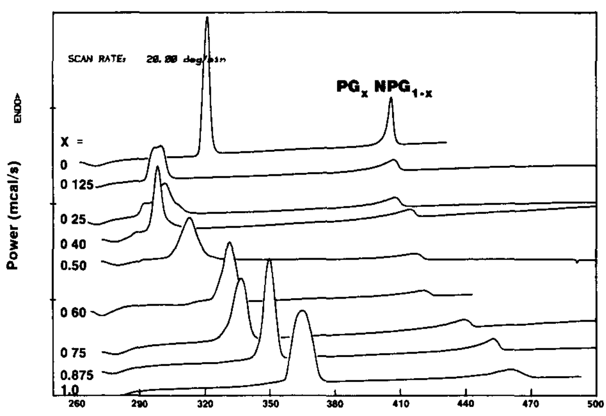
One class of such hydrocarbon PCM is the compound pentaerythritol and chemically related materials (3). Figure 2 shows the molecular structures of three of these compounds schematically. These three compounds are common synthetic chemicals which are produced in very large quantities for use in the manufacture of resin paints, plastics and explosives.

The pentaerythritol related compounds are being considered for their potential use in solar energy systems. They appear to have particular promise for applications as thermal energy storage materials in passive solar architectural systems. Ongoing research at the Solar Energy Research Institute includes systemmatic measurement of the thermophysical properties of the materials, basic studies designed to clarify the molecular processes involved in the solid state transformation, and design studies to evaluate the possible performance of such SS PCM's in solar passive systems.



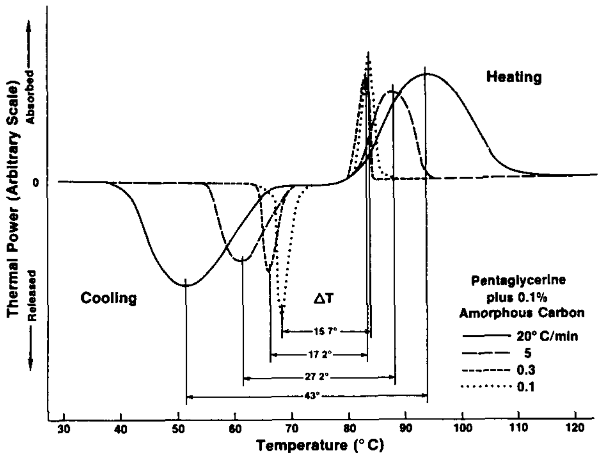
2. Schematic diagram of the molecular structure of three solid-state phase change materials.

Thermal Analysis has been used to measure the specific heats, transformation temperatures, melting temperatures and the latent heats of solid state transformation and of melting. We have discovered that binary mixtures of the compounds form stable solid solutions which also exhibit solid state transformations. Figure 3 is a series of thermal analysis recordings showing how the solid state transformation (the lower temperature peak) and melting (the higher temperature peak) are affected by the fraction, X, of pentaglycerine in solid solution with neopentyl glycol. The area under each peak is proportional to the energy absorbed in the transition.



A series of differential scanning calorimetry recordings of solid solution mixtures of pentaglycerine (PG) and neopentyl glycol (NPG.)

The kinetics of the solid state transformations have also been studied. These SS PCM's show strong tendencies to undercool, i.e., to give up their stored heat at significantly lower transition temperatures than those at which the energy was originally absorbed. Figure 4 shows both heating and cooling transition peaks as measured by thermal analysis at different heating/cooling rates. The greater the heating/cooling rate the greater the difference between the heating and cooling



4. A series of differential scanning calorimetry recordings of pentaglycerine showing both absorption and release of thermal energy at different heating/cooling rates.

transition temperatures. This kind of behavior is typical of PCM's, both solid state and solid/liquid, and is usually mitigated by the addition of a suitable nucleation agent which promotes the transformation. It was found that finely powdered graphite dispersed in the SS PCM (∿0.1% addition by weight) served as such a nucleating agent and greatly reduced the extent of undercooling.

The cyclic stability of the heat storage capacity is always a concern with PCM's. Preliminary measurements were made in order to evaluate the stability of the solid solution mixtures. A sample of neopentyl glycol (12.5 molar %) in solid solution with pentaglycerine (87.5 molar %) was cycled through the solid state transition for 732 cycles with no evidence of change in enthalpy of transformation nor change in the temperature of transformation. This rather limited experiment suggests that the solid solutions may be stable over useful numbers of storage cycles.

Design Analyses

A computer model was developed for a solar heated, thermal energy storage wall (a Trombe wall, Ref. 4) and used to estimate the bene[illegible]f incorporating SS PCM's into such a passive solar system. The Trombe wall was assumed to be incorporated into the south facing part of a small house. Tables 1 and 2 list the characteristics of the small house and the Trombe wall which were simulated.

The parameters of the Trombe wall and the characteristics of the SS PCM were varied systemmatically in order to determine the sensitivity of performance to changes in design parameters, to identify which SS PCM's may be best suited to this application , and to suggest how the SS PCM's should be changed to improve the Trombe wall performance.

Building Characteristics and Assumptions

Retrofit Test House at SERI--Denver, CO
(modeled as a single thermal zone)

Floor area	= 1080 ft^2
Windows	= double glazed
Ceiling	= R36
Walls	= R11
Crawl space walls	= R19
Infiltration	= 0.5 air changes per hour
Internal gains	= 53,000 Btu/day
Heating setpoint	= 60°F
Venting setpoint	= 76°F
Cooling setpoint	= 78°F

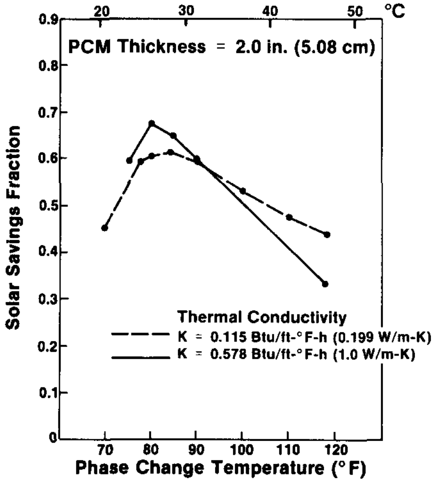
Trombe Wall Characteristics and Assumptions

Area	= 200 ft^2
Glazing	= double
Overhang	= 2.25 ft, 1.0 ft above top of glazing
Vent area	= 3%
Concrete (modeled with a thermal node every 2 inches):	
Thermal conductivity, k	= 0.7576 Btu/ft °F h
Density, ρ	= 140 lb/ft^3
Specific heat, C	= 0.2 Btu/lb °F
Phase-change materials (modeled without supercooling, with six thermal nodes):	
Density, ρ	= 66.55 lb/ft^3
Specific heat, C	= 0.5996 Btu/lb-°F
Heat of transformation, Q_t	= 52.03 Btu/lb
Parameters	
Thermal conductivity: k = 0.1156 Btu/ft °F h for base case	
Transformation temperature: T_t = 118.4°F for base case	

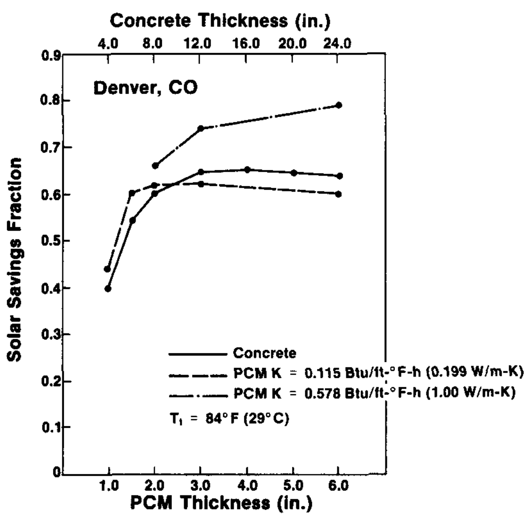
The performance was measured in terms of the calculated differences in annual heating energy requirements for the house with and without the Trombe wall. Annual heating requirements were calculated by the computer simulation using typical Denver weather information and summing the calculated hourly heating requirements.

Figure 5 shows the results of two sets of simulations in which the SS PCM transition temperature was varied. The fractional reduction in annual heating energy requirement attributable to the Trombe wall is shown as the Solar Saving Fraction (SSF). The optimum SS PCM transition temperature is shown to be about 29°C (84°C). Furthermore, as the second curve indicates, a SS PCM with a higher thermal conductivity could be expected to provide a higher SSF.

Figure 6 shows the results of simulations comparing the performance of Trombe walls of SS PCM and of concrete where the wall thickness is varied. Notice that the thickness of concrete required (upper scale) for a given SSF is about four times that of the SS PCM. If an improved SS PCM (higher thermal conductivity) were used, then its performance could be greater than any thickness of concrete wall.



5. The fraction of heating energy saved as a function of the transformation temperature in a SS PCM filled Trombe wall.



6. The fraction of heating energy saved as a function of Trombe wall thickness for a SS PCM filled and concrete Trombe wall.

TABLE 3
COMPARISON OF PHASE CHANGE THERMAL ENERGY STORAGE MATERIALS

TYPE CONSTITUENTS	LATENT HEAT OF TRANSITION (kJ/kg)	(BTU/lb)	TRANSITION TEMPERATURE (°C)	(°F)	MATERIAL DENSITY (Solid) (kgm^{-3})	(lb/ft^3)	RAW MATERIALS COST* ($/kg)	($/lb)	Ref.
SOLID-STATE PCM's									
Pentaerythritol (PE)	269	115.7	188	370	1390	86.7	1.56	0.71	3
Pentaglycerine (PG)	139	59.8	89	192	1220	76	1.61	0.73	3
Neopentyl glycol (NPG)	119	51.2	48	118	1060	66	1.30	0.59	3
Solid solution mixture of 60% NPG plus 40% PG	76	32.7	26	79	1124	70	1.46	0.66	3
Form-stable HDPE	188	81	133	271	960	60	(1.17) est.	(0.53) est.	2
Layered Porovskites	42-146	18-63	0-120	32-248	1100-1500	69-94	(<4.40) est.	(<2.00) est.	1
SOLID-LIQUID PCM's									
Sodium Sulfate Decahydrate	225	96.8	32	90	1464	91	0.10	0.045	5
Calcium Chloride Hexahydrate	190.8	82.1	27	81	1802	112.5	0.145	0.066	6
Magnesium Chloride Hexahydrate	168.6	72.5	117	243	1570	98	0.32	0.145	6
Calcium Chloride-Calcium Bromide Hexahydrate	140	61	14	58	1780	111	NA		6
Magnesium Nitrate Hexahydrate	162.8	70	89	192	1636	102.1	0.70	0.32	6
Magnesium Chloride-Magnesium Nitrate Hexahydrate	132.2	56.9	58	136	1630	102	0.47	0.215	6

*Raw Materials Cost based on current market quotations (Ref. 7).

7. Anon., Chemical Marketing Reporter, Vol. 223, No. 7, Feb. 14, 1983, Schnell Publishing Co., New York, New York.

A concrete Trombe wall four times thicker than a SS PCM wall would be about nine times heavier. These comparisons suggest that the SS PCM might offer the greatest advantage in applications such as solar retrofits to existing buildings and in new modular solar buildings where the use of massive concrete structures are impractical.

CONCLUSIONS

Research now underway may lead to the development of solid state pha change materials with thermal energy storage characteristics simila to presently available solid/liquid PCM's. Table 3 compares the characteristics of some SS PCM's under study with characteristics of some developed solid/liquid PMC's.

The greater cost of the SS PCM's will probably limit their applicability unless significant improvements can be made in their performance or unless their design advantages (e.g., reduced containment requirements; the possibility of direct contact heat exchange; and easily tailored transformation temperature) can offset the higher materials costs.

ACKNOWLEDGEMENTS

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WASTE HEAT RECOVERY
A REVIEW OF HARDWARE & APPLICATIONS

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1.0 INTRODUCTION

Every stack that exhausts flue gases into the atmosphere represents a irretrievably lost portion of the total available fuel energy. Depending on the temperature levels of the exhaust stream, this portion could be considerable and if recovered as useful heat, directly translates into savings in the total fuel bill.

In industrial furnaces the prime use of heat energy for thermal processing can be classified as below:

- Sensible heat to raise the temperature of the process stock
- Latent and sensible heat for phase transformation such as melting and evaporation
- Heat of reaction for chemical processes

While the above portion is useful as the primary function, there are associated with it two other expenditures of fuel energy in resolving the system heat balance:

- Heat loss by radiation through the walls and door of the furnace as well as ducts and flues

- Sensible and latent heat losses in the stack gases

Thermal processing methods are being continually improved to attain higher energy efficiency. Modern furnaces can often reduce radiation and leakage losses to insignificant levels. However, such improvements are beyond the scope of this presentation. The intent of this paper is to emphasize energy recovery from waste heat, especially stack gas.

1.2 WASTE HEAT SOURCES

Almost any industrial furnace is a source of waste heat and provides ample opportunity for heat recovery. Also any process stream that needs to be cooled down as dictated by the process is a source of waste heat.

Apart from thermal processing furnaces, many industrial plants generate effluents, which must be incinerated before being vented into the atmosphere. This often requires expenditures of considerable amounts of energy in the form of expensive fossil fuels to produce the necessary temperatures. Heat from such products must be recovered to improve the economics.

Every plant using fuel as a form of energy can identify a process or furnace for increased fuel efficiency. However, for the purpose of illustration, a few energy intensive industries and furnaces are identified below.

1.2.1 IRON AND STEEL MAKING:

In the steel making process the four major stages as far as energy use is concerned are:

- Mining and ore preparation

- Manufacture of pig iron in the blast furnace

- Manufacture of steel in open-hearth, electric or basic oxygen furnace

- Manufacture of finished steel products by rolling, forging, etc.

Prime candidates for waste heat recovery in the above processes are from the gases leaving B.O.F.'s or electric furnaces, and from flue gases leaving soaking pits and reheat furnaces.

1.2.2 ALUMINUM MAKING

The manufacture of aluminum products involves the following:

- Mining of bauxite ore
- Refining bauxite to extract alumina
- Reduction of alumina to obtain primary aluminum
- Rolling and extrusion to manufacture finished products

Waste heat recovery from aluminum melters greatly reduces the specific fuel requirements as typical flue gas temperatures from the melters are 2000° F.

1.2.3 CHEMICAL INDUSTRY

The chemical industry is so diverse and the processes numerous that it is difficult to treat them all in one paper. However, almost all chemical plants use some type of fuel fired heaters. The exhaust gases from these heaters are prime sources of waste heat. Many chemical manufacturers have realized this potential and new high efficiency units are specified, and old units retrofitted with waste heat recovery equipment.

Also, anytime a fluid is to be heated the engineer will try to match it with either a process or waste stream which is to be cooled for process reasons.

An ammonia plant is a typical example of a "total energy" plant, integrating its power and steam requirements for maximum efficiency. Steam at pressures as high as 1500 psig is generated using the sensible heat in the reformer flue gas, reformed gas and converted gas. This high pressure steam is expanded to 450 psig in back pressure turbines to produce the needed power for the compressor for ammonia synthesis. The back pressure steam is used in the reforming process as well as in a number of other plant utilities.

1.2.4 GLASS MANUFACTURING

The glass industry is another large consumer of energy, the largest portion going to melting furnaces. These have been a main target for energy conservation and heat recovery for some time.

In a typical "unit melter", flue gases leave the furnace at temperatures between 2300° F. and 2600° F. offering ample opportunity for heat recovery. Even in regenerative glass furnaces with brick checkers where combustion air is preheated by outgoing flue gases the final exhaust can be 1200° F. or higher, hot enough for further recovery.

2.0 WASTE HEAT RECOVERY METHODS

In this section, we will discuss the basic methods of recovering waste heat and typical applications of such methods. Essentially, waste heat recovery can be classified as

- Direct recovery
- Indirect recovery
- Secondary recovery

2.1 DIRECT RECOVERY:

This refers to utilizing the flue gases to preheat the fluid or stock that is thermally processed by the system. Typical examples would be

- Lengthening of a pusher type steel reheat furnace to preheat the steel stock
- Increasing the convection section of a fired heater in the chemical industry for heating the process fluid
- Providing a feedwater preheater (economizer) to preheat incoming feed water in a steam boiler
- Utilize the flue gases to preheat the feed stock (raw materials) to a glass melting tank

2.2 INDIRECT RECOVERY

Indirect recovery takes place when the flue gases are used to preheat the constitutents entering the combustion system. Fuel and combustion air are the two main components involved, and this method, therefore refers to fuel preheat and/or combustion air preheat by flue gases.

The most economical and efficient method of indirect heat recovery is preheating the combustion air. This heat recovery results in fuel savings which can be calculated by the following expression:

$$\% \text{ Savings} = \left[1 - \frac{LHV-(VO)(T2)(Cg)}{LHV+(VOP)(T2P)(Ca)-(VO)(T2)(Cg)}\right] \times 100$$

where

LHV	=	lower heating value of the flue
VO	=	volume of flue gases per unit of fuel
VOP	=	volume of combustion air per unit of fuel
T2	=	temperature of flue gases at furnace exit
T2P	=	temperature of preheated combustion air
Cg	=	specific heat of flue gases
Ca	=	specific heat of air

In his analysis of heat recovery by combustion air preheating, Prof. A. Schack points out how one unit of heat by combustion air preheat or fuel preheat is equivalent to more than one unit of heat by fuel. This so-called "valency" is a function of the preheat temperature and the flue gas temperature at furnace exit. For example a drying kiln fired by coke oven gas with a flue gas temperature of 750^{o} F. and air preheat of 570^{o} F., the air preheat has a valency of 1.1: however in the case of a forge furnace with flue gases at 2550^{o} F. and with air at 930^{o} F., firing the same fuel, the valency has a value close to 2.0.

Though similar results are achieved with fuel preheating, combustion air preheating is simplified in practice and more widely used. In the case of low BTU fuels such as blast furnace gas, often both the fuel and air are preheated to realize the required high temperatures in the furnace.

The enclosed Fig. 1 graphically shows the attainable fuel savings with natural gas firing at 10% excess air, with combustion air preheating.

Figure 1

% of FUEL SAVINGS
for various combustion air
preheat temperatures

FURNACE OUTLET TEMPERATURE ($^{\circ}$ F)	PREHEAT TEMPERATURE ($^{\circ}$ F)						
	600	700	800	900	1000	1100	1200
2300	24	28	31	34	36	39	41
2200	23	26	29	32	34	37	39
2100	22	25	28	30	33	35	37
2000	20	23	26	29	31	33	36
1900	19	22	25	27	30	32	34
1800	19	21	24	26	29	31	33
1700	18	20	23	25	27	30	32
1600	17	19	22	24	26	28	30
1500	16	19	21	23	25	27	29
1400	16	18	20	22	25	27	28

Fuel is N.G. at 10% Excess Air

2.3 SECONDARY RECOVERY

Secondary recovery utilizes the heat in the flue gases indirectly. The heat recovery could be in the form of preheating an external medium or the generation of power.

2.3.1 STEAM GENERATION

When the plant has requirements for process steam, a waste heat steam generator will save all the fuel which would have been used in generating this steam. This kind of heat recovery is very useful when the process requires steam in the low pressure range of 200 to 250 psig.

2.3.2 THERMAL FLUID HEATING

When heat sources are required at temperatures in the 500° F. to 700° F. range, (e.g. process heat exchangers), use of steam as the heating fluid becomes very expensive due to the very high pressures involved. In these cases thermal fluids can be used as the heating medium. Heat transfer fluids such as Dowtherm, Therminol, Syltherm, etc. remain in the liquid phase at high temperatures without high pressures.

Transferring the waste heat to thermal fluids results in fuel savings, which would otherwise be fired in the hot oil heaters.

2.3.3 MECHANICAL POWER

In certain chemical processes, a pressurized process stream at higher temperatures may have to be cooled and pressure reduced due to process reasons. In such cases, the process stream could be let down in a turbo-expander producing mechanical power. In the fluid catalytic cracking process, carbon on the expensive catalyst is burned away in a pressurized regenerator. The flue gases exiting the regenerator are approximately 50 psig and 1400° F. This stream can be let down in pressure in a turbo-expander to about 1000° F., and flue gas heat further captured in a waste heat boiler.

2.3.4 COGENERATION:

In any plant requiring both electrical energy and heat energy for thermal processing, combining the two needs results in very efficient use of available fuel heat output. Such co-generation is becoming very popular. Even plants which cannot consume all the electrical energy produced look favorably at cogeneration, as they can tie-up with the local utility and sell the extra power.

A glass plant with very high processing temperatures can provide a waste heat boiler downstream of the recuperator and use the generated steam in a turbo set to produce electrical energy. Part of the electrical energy could be used as boost in the glass tank itself.

A plant needing low pressure process steam could generate superheated steam at high pressure and expand it in a back pressure turbo set to generate electricity. The back pressure low-pressure steam will be used in the process, or a gas turbine could be provided to generate electrical energy, and the heat in the turbine exhaust used to produce the low pressure steam.

3.0 HARDWARE

3.1 RECUPERATORS & REGENERATORS

Indirect heat recovery is generally achieved by means of recuperators and regenerators. Recuperators and regenerators are operated in adaptations of either parallel or counterflow patterns. In counterflow, the heating medium enters, where the heated medium leaves. This pattern offers the advantage that the heated medium can theoretically approach the entry temperature of the heating medium. However, counterflow results in wide variations in heating surface temperature. Since the temperature is highest where the heating medium is entering, expensive materials may be required at this section.

In parallel flow, the two media enter the recuperator in the same end of the unit. The temperature of the heated medium is limited by the exiting heating medium temperature. Heating surface temperatures are relatively constant over the entire surface.

3.1.1 MATERIALS OF CONSTRUCTION

Depending upon application, recuperators are ceramic or metallic type. Ceramic heating surfaces offer several advantages including the ability to withstand high temperatures, resistance to corrosion, and low thermal expansion. However, gas tight construction is difficult; high temperature flexible seals are still under development. Also tubular ceramics remain relatively expensive. In low temperature combustion air preheaters (up to 900° F. gas temperature) glass tubes have been successfully used in preventing acid corrosion at costs competitive with metallic units.

Metallic recuperators, as the name implies, have heating surfaces made of metal alloys. Advantages include low cost, gas-tight construction, and material availability and selection. The proper application of materials and type of heat exchanger is essential to successful and reliable operation.

3.1.2 RADIATION RECUPERATORS

This type of unit is specified for application where flue gas temperatures are in the range of 1800° F. to 2800° F. At these temperatures radiant heat transfer is predominant. Pressure drops on the gas side are negligible owing to low flow velocities.

The stack type radiation recuperator is made of two concentric metal cylinders with an annular gap, between the two cylinders. (See Fig. 2) The flue gas flows inside the inner shell and radiates heat to the inner shell; the heated medium flows in the annular gap and picks up this heat by convection. The combustion air exerts external pressure on the hot inner shell and can cause it to collapse, if the pressure is excessive. For that reason, this design is generally limited to 2 psig pressure.

For more severe conditions of pressure and temperature, the cage type radiation recuperator is employed. These units incorporate a circle of vertical tubes inside a refractory lined shell. The tubes receive heat by

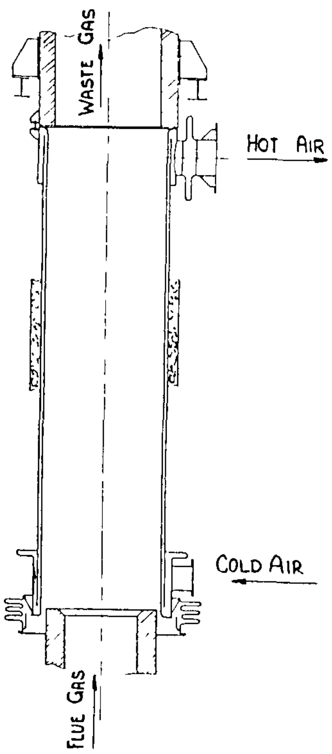


Fig. 2 STACK TYPE RADIATION RECUPERATOR WITH PARALLEL FLOW

direct radiation from the flue gases as well as back radiation from the refractory lining and transfer it to the heated medium flowing inside the tubes.

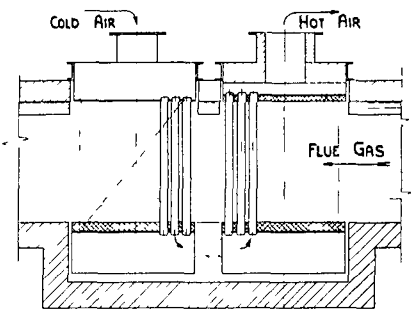
Due to the exponential relationship between temperature and radiant heat flux, this type of recuperator is best suited for continuous processes where flue gas temperatures remain high. Glass tanks, soaking pits, and forge furnaces are typical applications.

3.1.3 CONVECTIVE RECUPERATORS

At temperatures below 1600^{o} F. to 1800^{o} F., radiation drops off rapidly. For effective heat transfer at such temperatures, convective recuperators should be used. Since convective heat transfer is velocity dependent, means should be provided in the system to overcome the flue gas side pressure drop.

Depending on the mode of flue gas flow, convective recuperators are divided into canal and flue-gas-thru-the tube recuperators.

The canal recuperator is an all tubular convection unit with the tubes located perpendicular to the flue gas flow. (See Fig. 3) The heated medium usually flows inside the tubes. These units have been designed for air temperatures as high as 1200^{o} F. Air side pressure drops are 10" to 12" W.C. with flue gas side drops generally around 0.25" to 0.5" W.C.



They are self-supporting and are very cost effective. For light dusty service sootblowers can be pro-vided to keep the heating surfaces clean.

FIG. 3 CANAL RECUPERATOR

The flue gas-thru-the tube type is a vertical tubular convection heat exchanger designed to handle gases containing particulate matter. (See Fig. 4.) Combustion air is channelled back across the tube nest, usually in multiple pass counterflow. Flue gases flow inside the tubes at fairly high velocities to keep the particulates in suspension.

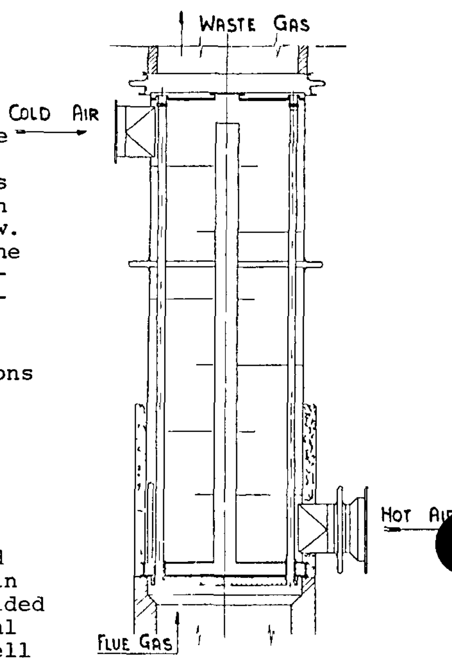


Fig. 4.
Flue Gas-Thru-The-Tubes Recuperator

Preheating capabilities and temperature limitations are similar to the canal recuperators. Flue gas side pressure drops are normally in the 3" to 5" W.C. range. Successful applications include fluidized bed reactors, incineration systems, and hot blast cupolas. A main expansion bellow is provided to absorb the differential expansion between the shell and the tube bundle. Each tube has its own expansion bellow to compensate the differential expansion between tubes.

3.1.4 ROTARY REGENERATORS

The rotary regenerator incorporates a heating surface matrix of either ceramic material or metallic material, which rotates, in such a way that flue gas and air flow over them alternately. This type of heat recovery unit is often favored for its compactness. Leakage between the two streams is unavoidable even though special seals keep it down to a minimum.

Cleaning equipment like sootblowers may be used; however harsh fouling conditions tend to plug up the unit. Stage seals require periodic replacement. Ceramic matrix design eliminates the need for seals due to the low thermal expansion rates and close construction tolerances. Metallic matrix is suitable for flue gas temperatures up to 1000° F. and ceramic matrix is used up to 1500° F.

3.2 WASTE HEAT BOILERS & THERMAL FLUID HEATERS

Fire tube waste heat boilers are used to steam pressures up to 400 psig. Mostly, these boilers are located with their axis horizontal; however, for streams with a heavy dust burden, vertical orientations with large tubes are available.

For pressures over 400 psig, the water tube design is generally more ecomomical. Multiple drum boilers with integral steam and water drums are common, as they are simple in both construction and operation. This design is practical to operating pressures of 1000 psig, beyond which the integral drums get too heavy and uneconomical. For higher pressures, the steam drum is external to the system with downcomers and risers connecting the boiler heating surface to the drum. Depending on the heating surface configurations, either natural circulation or forced circulation may be employed. Each flow circuit in the boiler section is provided with orifices to balance the flow between the tubes and maintain proper circulation ratios. Lack of circulation will cause overheating of tubes and their consequent failure.

Thermal fluid heaters use heat transfer fluids like Dowtherm, Therminol, Syltherm, etc. as the heat transfer medium, and form a closed loop. The system pressure drop is overcome by means of circulating pumps.

If flue gases are at temperatures above 1800° F., the heaters are normally designed as a radiant convective unit, with a helical or serpentine coil radiant section and a multiple pass finned tube convection section. Below 1800° F. the radiant section is omitted.

The heat transfer fluid is normally in the liquid phase; vapor phase heaters being specified only for high hot oil temperatures and large heat duties.

3.3 INCINERATORS

Modern industrial plants produce many effluents which have to be thermally destroyed before they are exhausted. These effluents may or may not have significant heating value. In the latter case, valuable fossil fuel like natural gas or oil may have to be used to realize the necessary temperatures for their incineration. Use of recuperators to preheat the combustion air and/or the effluent by the incinerator exhaust flue gases appreciably reduce this fuel requirement. Secondary heat recovery may be possible to further utilize the waste heat.

Proven systems are available for incineration of low BTU effluent, solid municipal and industrial wastes. Fluid bed and static bed incinerators are very common and pyrolysis reactors, generating clean gas are gaining acceptance by the industry. In all these instances, the flue gases leaving the incinerators contain valuable heat, and heat recovery is a must to justify the economics of these systems.

4.0 SUMMARY

As outlined, it is obvious that waste heat sources are abundant and the hardware for its recovery is available. All of the examples are economically feasible and have proven merit. Proper selection and design of a waste heat recovery system can help any plant in reducing its energy dependency.

DEVELOPMENT OF HIGH EFFICIENCY DROPLET HEAT EXCHANGERS

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INTRODUCTION

One of the key problems facing the designers of high temperature energy conversion systems is that of achieving effective heat transfer at temperatures which extract the full thermodynamic potential of the system heat source. The maximum operating temperature and effectiveness of conventional heat exchangers are limited by the physical separation of the hot and cold fluid streams by a solid wall with its associated pressure loss, thermal stress corrosion, and material deposition problems. For the case of metal heat exchangers, at temperatures not much above 1000°K (1340°F) exchanger materials which are sufficiently high temperature compatible become forbiddingly expensive and suffer dramatically reduced lifetimes. For ceramic devices, recent developments have indicated small but significant advances in utilizing small scale heat exchanger components reliably at temperatures up to 1500°K (2250°F) (1). These devices, however, have comparatively poor surface-to-volume characteristics and, in the larger scales appropriate to high power industrial applications (e.g., 100 MW and above), are expensive to manufacture and prone to thermal shock. Conventional pebble bed heaters can achieve peak temperatures above 2000°K (3140°F) but must operate in a batch mode and are subject to considerable material carryover from ceramic spalling under thermal and mechanical cycling fatigue.

Mathematical Sciences Northwest, Inc. (MSNW) has been investigating the concept of droplet heat exchangers (DHX) which utilize two-phase direct-contact heat transfer between two counterflowing media to mitigate the difficulties associated with conventional heat exchangers. A DHX device would consist of a vertical column containing a shower of molten droplets (or solid particles) falling downward through an upward directed gas stream. Heat transfer could occur from droplets to gas or vice versa, depending on the desired application, and a phase change in the droplet or particle material from liquid to solid or solid to liquid could also be exploited. For temperatures in the 1500-1700°K (2250-2600°F) range, candidate droplet materials of molten glasses slags comprising various SiO_2-CaO-MgO-Al_2O_3 systems have been proposed (1,2). The potential reliability of the concept should be good; there are no tubes which can rupture, since fouling can be minimized by skimming off contaminant materials in the molten phase and because corrosion of the droplet materials can be minimized with many of the proposed ceramics currently available (2). A DHX device should also exhibit high heat exchanger effectiveness due to the very large surface area-to-volume ratios available in a dense cloud of small droplets.

The high temperature, dirty gas capabilities of droplet heat exchangers lend themselves to heat transfer applications such as those in coal-fired combustion power plants. The process temperatures in these plants are limited both by the gas-to-steam heat exchangers and by steam turbine blade metallurgical limits. A droplet heat exchanger deployed in a coal combustion chamber could extract heat at temperatures close to the stoichiometric flame temperature of coal (e.g., 1640°K or 2500°F) and transfer that heat to a clean gas stream to drive a gas turbine topping cycle, allowing estimated thermal cycle efficiencies for a combined cycle in excess of 50%, compared to ~40% for conventional steam cycles. Other potential applications such as in coal gasification, hydrogen heating, solar thermal power plants, and various chemical processes are also possible.

Following is an introduction to the general principles of operation of a molten droplet heat exchanger and the basic heat transfer and fluid flow phenomena governing its behavior.

PRINCIPLES OF DHX OPERATION

The droplet heat exchanger operates via the convective, conductive, and radiant heat exchange among the downward falling cloud of droplets, the upward flowing gas, and the walls of the exchanger tower itself. Because the droplet material may be solidified and remelted during each pass through the device, it could be continuou remanufactured, minimizing its mechanical stresses and reducing problems related to thermal shock. The droplet heat exchanger concept requires a uniform droplet size to maximize effectiveness for each specified operating condition. Droplets should neither be carried out of the top of the column with the gas stream (as could happen for drops much smaller than desired) nor be permitted to leave the bottom of the tower with significant amounts of thermal energy (as would occur for larger than desired drops). The rate of droplet fall, its heat capacity, heat transfer rate, and total transit (residence) time through the heat exchanger strongly depend on droplet size. Smaller than average droplets fall more slowly through the counterflowing gas due to their lower weight relative to the opposing drag force and, consequently, have more time for heat transfer. However, they contain less energy, have a higher heat transfer coefficient, and have a higher surface-to-volume ratio than the desired drops and, hence, cool more quickly than desired. Drops swept out the top of the heat exchanger would require the use of a separator at the outlet. Large drops contain more energy, transfer heat less effectively, and fall faster than the desired drops; hence, they are more likely to reach the tower base with residual energy. For these reasons, a DHX shower composed of droplets of relatively uniform size is important for optimal heat exchanger performance. Droplet formation tests have been carried out at MSNW to simulate the behavior of the viscous materials considered for very high temperature operation and have demonstrated that uniform droplet streams can be formed at conditions for large DHX applications. These tests will be discussed briefly in the last section of this paper. In addition to size uniformity, a homogeneous distribution of drops in the gas phase is desirable to enhance the flow about individual droplets as well as to reduce the possibility of droplet collisions and agglomeration.

DHX INJECTOR/GAS PORT FLOW MODELS

One possible configuration for the top and bottom portions of a large scale DHX is shown in Figure 1. Here a large number of molten fluid streams are passed through droplet injector heads at the top into the counterflowing gas stream. Gas flow is uniformly introduced through inlet manifolds at the bottom and proceeds upward through the droplet shower. The principal requirements of the top portion of the heat exchanger are to provide distributed outflow ports for the gas exiting the heat exchanger, distributed liquid injection orifices with size and spacing to provide a uniform droplet dispersion across the heat exchanger column, and to minimize radial gas/droplet interactions which result in large numbers of drops contacting the column walls or other droplet streams. Since many thousands of liquid injection orifices will be required for high rates of heat transfer, modular configurations grouping large numbers of injectors into assemblies which can be attached to common liquid flow manifolds are desired. Two-dimensional flow studies of various gas exit manifold/droplet injector modular configurations have provided insight into the flow design issues of this portion of a DHX device.

An approach which avoids directing the droplet streams into either the wall or other droplet streams is shown in Figure 2. In this scheme, a bellmouth gas exit vent flaring out from the upper wall region is combined with injecting the droplet streams at angles directed radially inward, which compensates for the radial component of gas flow as it enters the gas exit vent. The figure depicts the 2-D droplet trajectories which result under steady state DHX flow conditions. The 1 mm diameter droplets here are injected at a velocity U_d^{in} which sums with the exit velocity of the gas V_g^{out} such that their vector total equals the terminal velocity U_t at the temperature and pressure of the top of the DHX column, i.e., U_d^{in} +

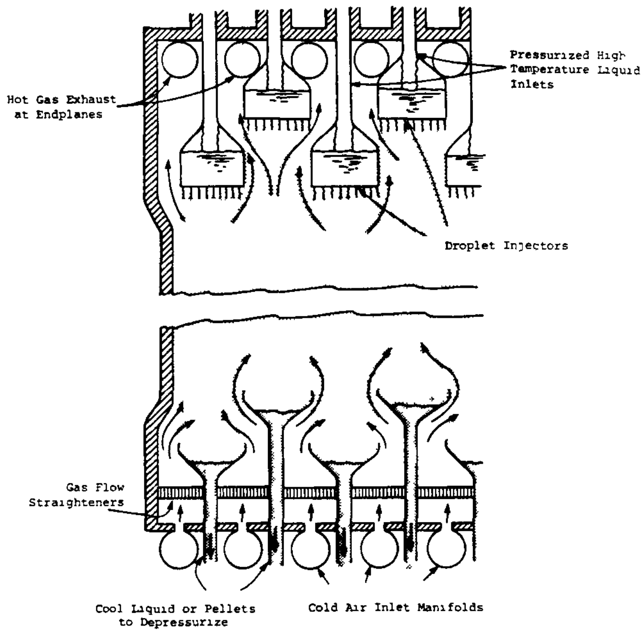

Figure 1. Schematic of Droplet Injection/Collection and Gas Manifolding Configurations

$V_g^{out} = U_t$. The operating assumptions used for this figure are that $|U_d^{in}| = |V_g^{out}| = 0.5\ U_t$, and the column temperature and pressure are 400°K and 1 atm, respectively. The number of orifices (1585) and frequency of injection (388 Hz) represent conditions which balance the thermal capacitances of the droplet and gas streams. More will be said of this rationale in the next section. The maximum trajectory injection angle is 35° from the vertical; this for the outermost orifice ring. Note that a gain in orifice plate area is made available by increasing the diameter of the injector head to exceed the column diameter. Thus, this configuration yields one method of providing a uniform distribution of droplets in the proposed droplet heat exchanger flow field.

DHX HEAT TRANSFER PERFORMANCE PREDICTIONS

The drop injection/gas exhaust and the drop collection/air inlet regions of a large scale device will comprise a relatively small fraction of the column height, thus leaving the majority of the column to exhibit primarily one-dimensional flow and heat transfer behavior. Figure 3 shows a schematic of a one-dimensional model of a DHX device. As depicted, the velocity and temperature of each of the phases is a function of axial position in the column. The individual

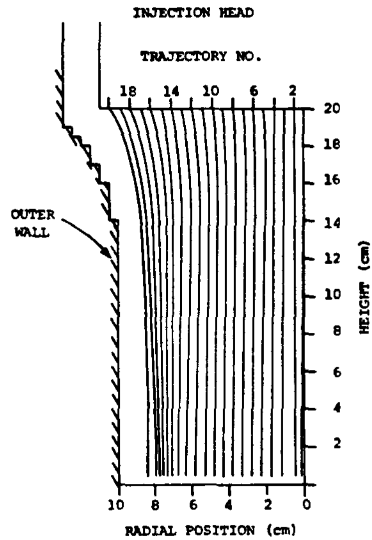

Figure 2. Droplet Trajectory Pattern in a Bellmouth DHX Column with Angled Orifices and Enlarged Injection Head

molten streams are each injected at the top at the same velocity and temperature, and break up into droplets of a uniform size. No transverse component of velocity is considered. Each liquid jet emanating from its respective orifice forms droplets of a diameter, d, at frequency, f, as a function of (a) the thermophysical properties of the droplet material at T_d^{in}; (b) the density of the gas at pressure P_{column} and T_g^{out}; (c) the diameter of the orifice, d_o; and (d) the relative velocity between the jet and gas, U_r. The droplet breakup is modeled as a function of these parameters according to the instability theory of Wickemeyer [3] and Weber [4] whereby an initial random disturbance at the orifice propagates in the jet as it travels downward and grows at the characteristic fastest natural rate, resulting in a natural wavelength, λ, (distance between the droplets) for a constant jet velocity, U_j. The model uses jet velocity and droplet size to determine the frequency and injection orifice meter, d_o, according to continuity. Since natural disturbances d to be random, external excitation may be used to improve the stability of the breakup process. The use of mechanical vibration and pressure disturbances to facilitate droplet breakup and to assure uniformity of droplets has been done in MSNW droplet formation experiments (discussed later) and is described in detail in References 2, 3, and 5.

The influence of the thermal capacitances of the two streams on the heat exchanger effectiveness ε may be expressed as a function of their ratio $C_S = (\dot{m}c_p)_{gas}/(\dot{m}c_p)_{drops}$. For $C_S > 1$, the droplet temperature change per unit length of the column is large relative to

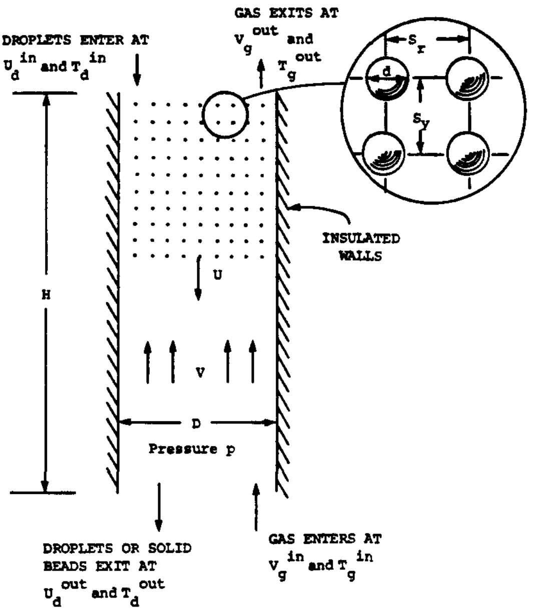

Figure 3. One-Dimensional Droplet Heat Exchanger Model

that for the gas. For $C_S < 1$, an opposite pattern is found in which there is very little temperature decline in the drops down the tower while the gas heats readily. The $C_S > 1$ condition may result in excessive column lengths as the capacitance mismatch grows, while the $C_S < 1$ condition may permit large levels of untapped thermal energy in the droplets leaving the heat exchanger. A reasonable compromise is to match the thermal capacitances of the two streams, i.e., $C_S = 1$. It also can be shown that the maximum availability of useful energy for the exchanger process occurs when $C_S = 1$. For these reasons, the DHX performance studies have employed the C_S equal to unity condition.

The studies here have identified ranges of several design parameters for high effectiveness, high temperature heat exchangers using molten glass (55 percent SiO_2, 45 percent Na_2O) as the droplet material. Preliminary thermodynamic cycle analyses have indicated that an optimum DHX gas pressure of 12 to 13 atm would be associated with an approximately 1600°K (2420°F) glass droplet injection temperature with a Brayton cycle power extraction loop. Since the droplet exit temperature approaches the inlet gas temperature as the column is lengthened, a DHX of any configuration can be designed to any specified effectiveness simply by employing a heat exchanger tower of sufficient height.

Figure 4 shows the variation of effectiveness with column height for DHXs designed for a maximum of 80 percent effectiveness and which employ different sized droplets under both low and high pressure operating conditions, again with $C_s = 1$. The gas enters in each case at the temperature corresponding to an isentropic compression from ambient conditions to the column pressure. In this case at p = 1 atmosphere, $T_g^{in} \approx 300°K$ (80°F) and $T_d^{in} = 1200°K$ (1700°F) and for p = 12 atmospheres, $T_g^{in} = 600°K$ (610°F) and $T_d^{in} = 1100°K$ (1520°F). In all cases, $U_d^{in} = V_g^{out} = 0.5\ U_t$. The trend toward greater effectiveness with increasing column height and pressure and diminished droplet size is evident. Much of the increased effectiveness of smaller droplets may be attributed to the greater heat transfer surface area to volume (or mass) ratios characteristic of smaller droplets. The figure also shows that achieving high effectiveness with low pressure devices or with droplets of 2-3 mm diameter or larger would require heat exchanger towers of great height. An additional factor which also constrains the liquid droplets to sizes less than 2.0 mm and constrains injection velocities to less than the terminal velocity is that of the breakup stability of the liquid drops after formation in free fall in the counterflowing gas stream. For the molten glasses and slags of interest, the maximum diameter for stable drops is on the order of 1.7 to 2.0 mm depending on DHX gas properties. Thus, the droplet sizes which are desirable from the standpoint of droplet heat exchanger height are also stable.

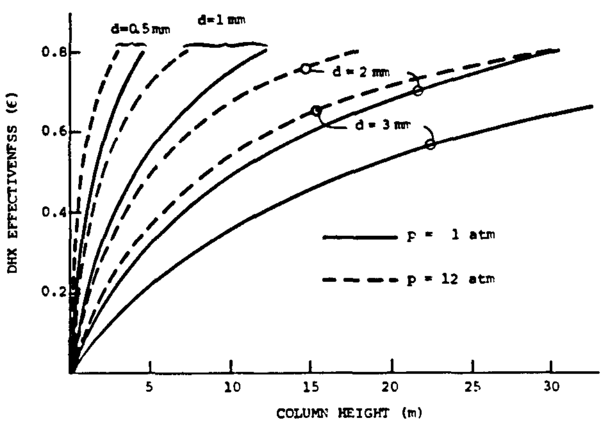

Figure 4. DHX Effectiveness Variation With Droplet Size, Column Pressure, and Height

Although high effectiveness can be achieved through reducing the droplet size, reduced drop size has several effects on DHX operation and configuration. Figure 5 shows the calculated variation in the DHX column diameter to be expected for three droplet sizes as a function of the gas and droplet velocity at the top of the column. These velocities are expressed as decimal fractions of the droplet terminal velocity, U_t, at the top of the column. The droplet and gas velocities used in these calculations were chosen so that $U_d^{in} + V_g^{out} = U_t$. Conditions within the DHX are such that the relative velocity remains approximately constant. The DHX configuration parameters shown in Figure 5 provide 100 KW_{th} of heat transfer at a specified effectiveness of 80 percent with $C_g = 1$ at a column pressure of 12 atmospheres. The temperature conditions for all cases are T_d^{in} = 1600°K (2420°F), T_g^{in} = 600°K (620°F), and T_g^{out} = 1400°K (2060°F). The increased DHX column diameter accompanying smaller droplet sizes is required because the smaller droplets are increasingly unable to overcome the adverse aerodynamic drag, i.e., droplet mass shrinks as d^3 while drag force only decreases approximately with $\sqrt{d}$ and $\sqrt{U_r}$. The upward gas velocity must be limited to a fraction of the droplet terminal velocity to allow the downward drop velocity required for counterflow heat exchanger operation. Since a larger column diameter lowers the upward gas velocity for a fixed total heat transfer rate, the relative gas and droplet velocities can be maintained at the desired fraction of the lower velocity of the smaller drops. These and similar calculations have shown that as droplet size decreases, the effectiveness of a given height DHX increases, but a larger diameter is also required to achieve a desired total heat transfer rate. These calculations also imply that the required number of droplet orifices increases as droplet size is decreased for a fixed heat transfer rate. Typically, the number of orifices may range from 300 to 2000 for the conditions of Figure 5, corresponding to 2.0 mm and 0.5 mm droplets, respectively, at the $U_d^{in} = V_g^{out} = 0.5\ U_t$ condition.

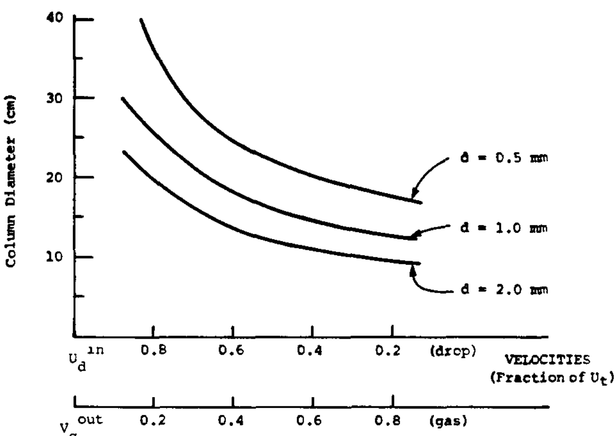

Figure 5. DHX Column Diameter Dependence

These performance studies show that for high power requirements, molten glass DHX devices of reasonable size result. For example, a 100 MW_{th} device could operate at 80% effectiveness under the thermal conditions of Figure 5 with an approximate diameter of 5 meters and height of 7 meters for a droplet size of 1 mm at $U_d^{in} = V_g^{out} = 0.5\ U_t$.

DROPLET FORMATION EXPERIMENTS

The importance to the DHX concept of being able to generate a [illegible]wer of uniformly and optimally sized droplets requires an understanding of the droplet formation process in candidate materials. The fluid properties, combined with the constraints on droplet size for droplet breakup stability and on providing effective heat transfer in droplet heat exchangers of reasonable size, define a range of liquid jet injector operating conditions which govern the droplet formation process. These droplet formation conditions fall in a range of the controlling parameter space for which very little experimental and analytical work is available. Therefore, a series of experiments has been conducted at MSNW to simulate droplet formation of glass or slag materials and to determine the required exciting vibration frequencies, amplitudes, and flow conditions for which uniform drops in the desired size range can be made. Fluids such as silicone oils and glycerine-water mixtures have been found to adequately simulate molten glass droplet formation with droplets in the size and velocity range appropriate to DHX devices. The droplet generation experiments have indicated distinctly preferential operating ranges to assure uniform droplet streams. Maps of these preferential flow regimes have been made to aid in the future development of the DHX concept. To date these tests indicate that it will be possible to form uniform molten glass or slag drops with reasonable amplitude jet disturbances for high temperature DHX devices. The data also show that a significant range of drop formation sizes, frequencies, and injector flow conditions are available for matching the drop formation characteristics to the DHX requirements.

CONCLUSIONS

The feasibility of a continuously operating, high temperature and high pressure molten droplet heat exchanger appropriate to many high power industrial applications has been supported by DHX performance modeling results and droplet generation experiments. These results indicate that such devices could be highly effective and more reliable than current commercial and experimental heat exchangers utilized at very high temperatures. The effects on DHX operation of gas pressure, droplet size, and relative gas/droplet velocities emphasized in the one-dimensional modeling have shown that DHX devices of reasonable physical size and complexity are possible. Two-dimensional gas/droplet flow models have provided insight into the flow behavior and feasibility of various droplet injection/gas exhaust port configurations to be used to achieve uniform distribution of the droplets in the counterflowing gas stream.

To further evaluate the potential of the droplet heat exchanger concept and to contribute needed technical data for its future development, an experimental subscale droplet heat exchanger is currently under construction at the MSNW energy laboratory. The device is designed to operate up to 20 KW_{th} at 10 atm operating pressure with silicone oil as the droplet fluid. In addition, a program is underway to identify specific molten liquid candidate materials and high temperature structural materials to be used in building large scale DHXs. The design of an experiment to characterize the droplet formation processes in high temperature molten glasses and slags also has begun.

ACKNOWLEDGEMENTS

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HIGH TEMPERATURE BURNER-DUCT-RECUPERATOR SYSTEM EVALUATION

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BABCOCK & WILCOX

RESEARCH AND DEVELOPMENT DIVISION

INTRODUCTION

Babcock & Wilcox is participating with the U.S. Department of Energy (Idaho Operations Office through the Office of Industrial Programs) in cooperative agreement DE-FC07-81ID12296 to design, construct, install and evaluate a high temperature burner-duct-recuperator system (HTBDR). The system is to be capable of delivering 2000°F (1800°F min) preheated combustion air to the combustion system of a steel mill soaking pit; the evaluation site being located at the Koppel, Pennsylvania steel melting facility of the Tubular Products Group of B&W.

The purpose of the project is to advance the state-of-the-art in industrial waste heat utilization by developing an HTBDR system which is both technically and economically acceptable to industry. The system being designed by B&W is intended to operate in flue gas streams of 2450°F which contain contaminants from hot topping compounds and scale (iron oxide) and is intended to recover enough energy from the flue gases to deliver the 2000°F preheated combustion air when the soaking pit is operating under maximum temperature conditions. Although the HTBDR system being designed by B&W will be evaluated in a steel mill soaking pit, the technology will be applicable to other high temperature industrial furnaces (e.g., aluminum or metal reheat industries) and to low temperature, highly corrosive flue gas streams where metals cannot survive.

The 1.8 million dollar project is divided into three phases. B&W is contributing 25% of the contract funds and is supplying installation and site engineering services as well as insulation engineering services at no cost to the D.O.E. The project phases are shown below:

HTBDR Project Schedule

Phase	Activity
1	System design, prototype verification of design, energy audit of evaluation site
2	Construction, Installation and Check-out
3	System Evaluation

The project is currently at the end of Phase 1 and the information described herein from the design effort and prototype testing is current as of December, 1982. Due to the complexity of the project and the magnitude of data available, only a summary of the concept, thermal and fluid flow analyses, material characterization and prototype testing will be presented.

APPROACH

The approach used to design the HTBDR system was to bring together a multi-discipline team from several B&W divisions to design the recuperator system and North American Manufacturing Company to design the burner. The B&W divisions participating in the project are:

Participating Babcock & Wilcox Divisions

- Research and Development Division
- Tubular Products Group
- Insulating Products Division
- Bailey Controls Company

The B&W R&D Division has the prime responsibility for the HTBDR design. The seven technical disciplines cooperating in the design effort are shown in Figure 1. The Tubular Products Group engineering and operating staff provide "user perspective" design efforts as well as site retrofitting and installation. The Insulating Products Division has provided guidance for the use of ceramic fiber insulating products on the air side and flue side systems

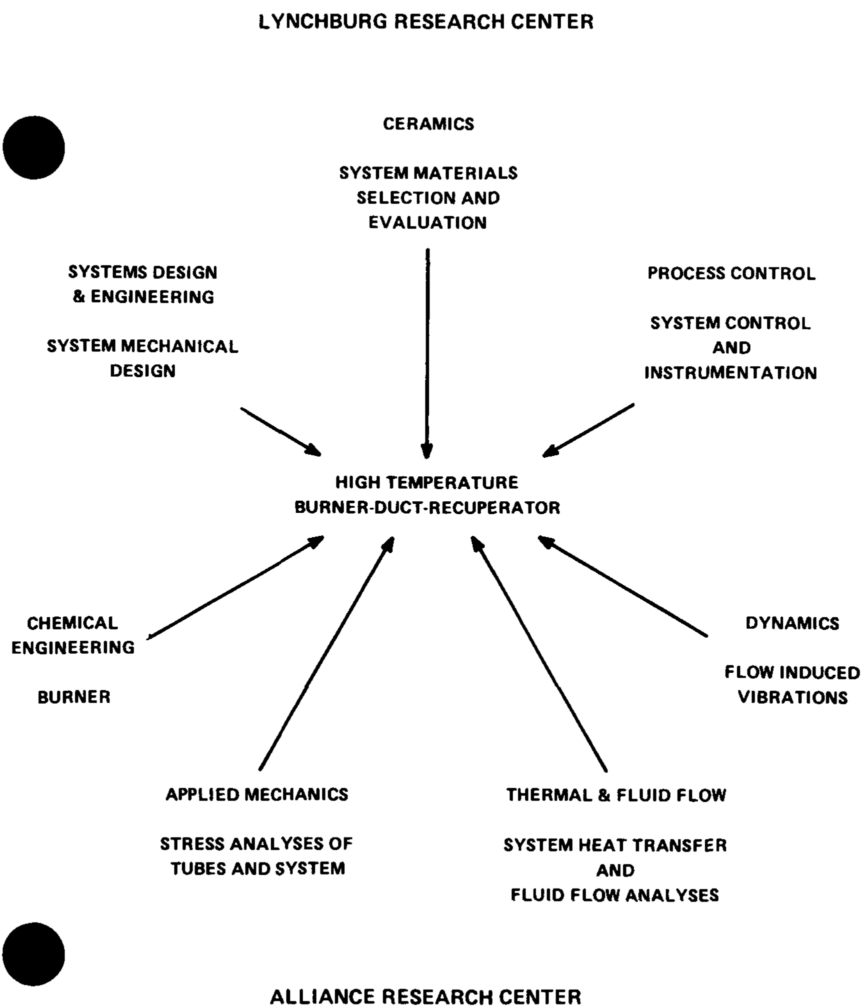

Figure 1. Research and Development Division Technical Disciplines Participating in the HTBDR Design

and the Bailey Controls Company has provided guidance on the interfacing of the new recuperator system controls and instrumentation with the existing soaking pit.

CONCEPT

The concept developed by the design team to recover the heat in the waste gas stream consists of two ceramic tubes; one tube open on both ends inserted into another tube which is closed on one end, i.e., bayonet style (see Figure 2). The tubes are suspended vertically from the plenums into the flue of the soaking pit using air cooled, metallic tube sheets. As seen in Figure 2, combustion air is blown into the upper plenum where it begins the heat exchange process with the hot flue gases by flowing down the inner tube, turning around at the bottom of the outer tube and flowing up the outer tube to the lower plenum and then out of the recuperator. Air flow direction through the recuperator could, of course, be reversed.

Ceramic fiber insulation is used to line the walls of the plenums and the surfaces of the tube sheets as well as the ducts and burner. Ceramic fiber products are also used to provide individual support sleeves and seals for the tubes. The tubes in this concept rest on the sleeves and seals and are not constrained from moving due to thermal expansion. This design reduces or eliminates mechanical stresses on the ceramic tubes.

Figure 3 is an artist illustration of how the tubes will be supported by the metallic tube sheets. Figure 4 shows the ceramic fiber sleeves and O-ring seals used for the inner (smaller sleeve) and outer tubes.

THERMAL AND FLUID FLOW DESIGN

General heat transfer and pressure drop models were developed to predict the thermal/fluid performance of a large system of the bayonet units depicted in Figure 2. These models incorporated results from more detailed heat transfer and pressure drop models of a single bayonet unit. After a number of potential designs were examined, a system was selected that comprised a three pass recuperator with fifty ceramic tube assemblies/pass interfaced with an existing two pass metallic recuperator in the soaking pit flue. Figure 5 shows schematically how the ceramic recuperator will be connected between the metallic recuperator and the soaking pit. A summary of the system specifications is shown in Table 1.

Air side and flue side pressure drop predictions obtained from the computer models are shown in Table 2. Since the soaking pit operates in low and high fire modes, both firing conditions were analyzed.

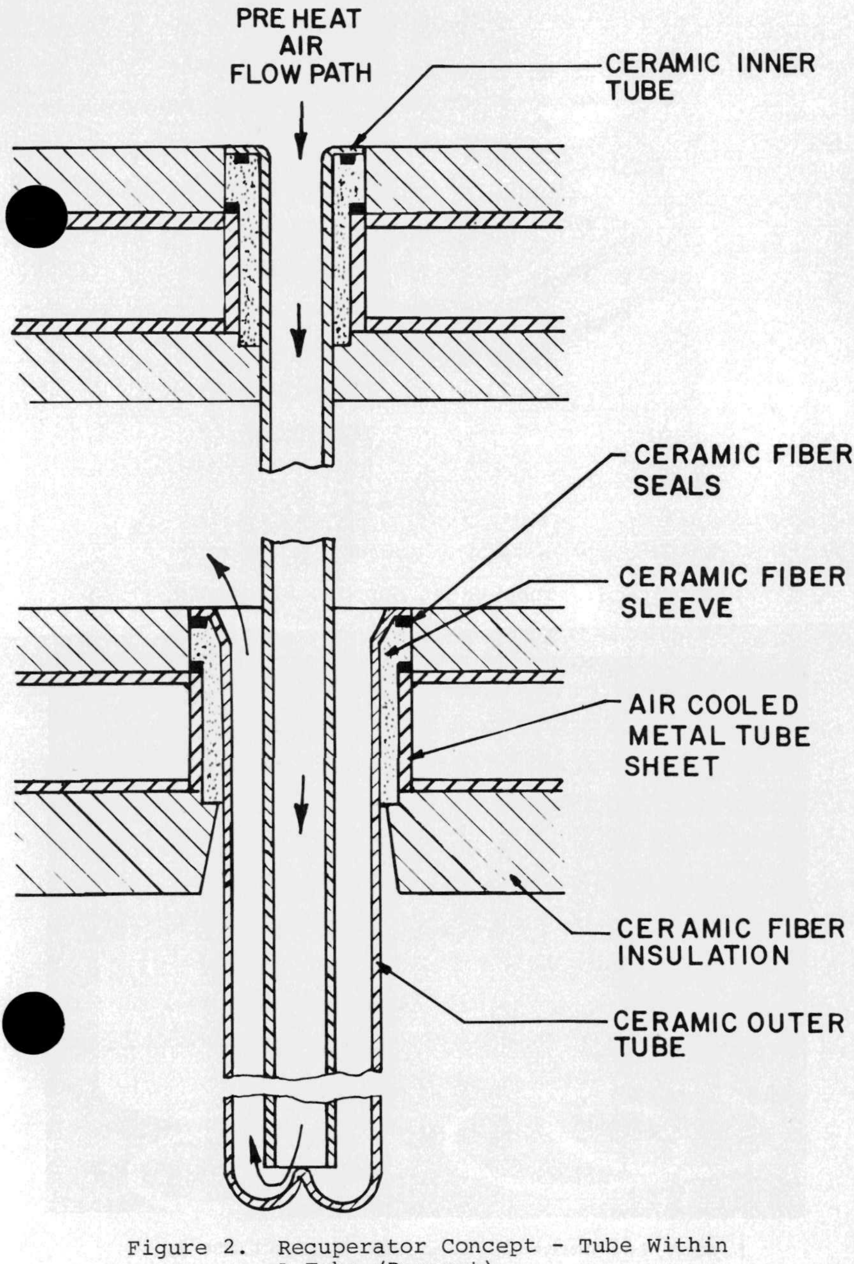

Figure 2. Recuperator Concept - Tube Within A Tube (Bayonet)

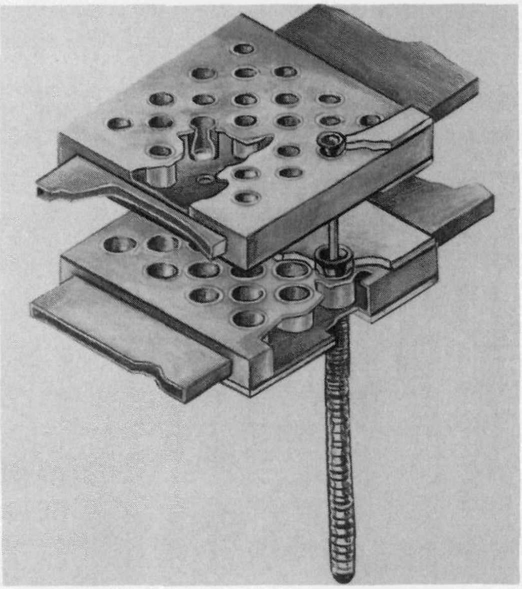

Figure 3. Tube Sheet Support Structure For the Ceramic Tubes

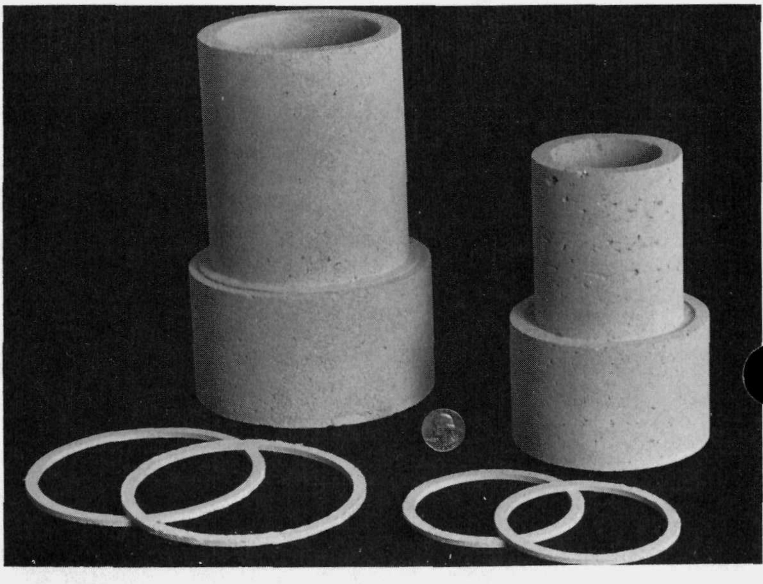

Figure 4. Ceramic Fiber Sleeves and Seals For the Outer (Left) and Inner (Right) Tubes

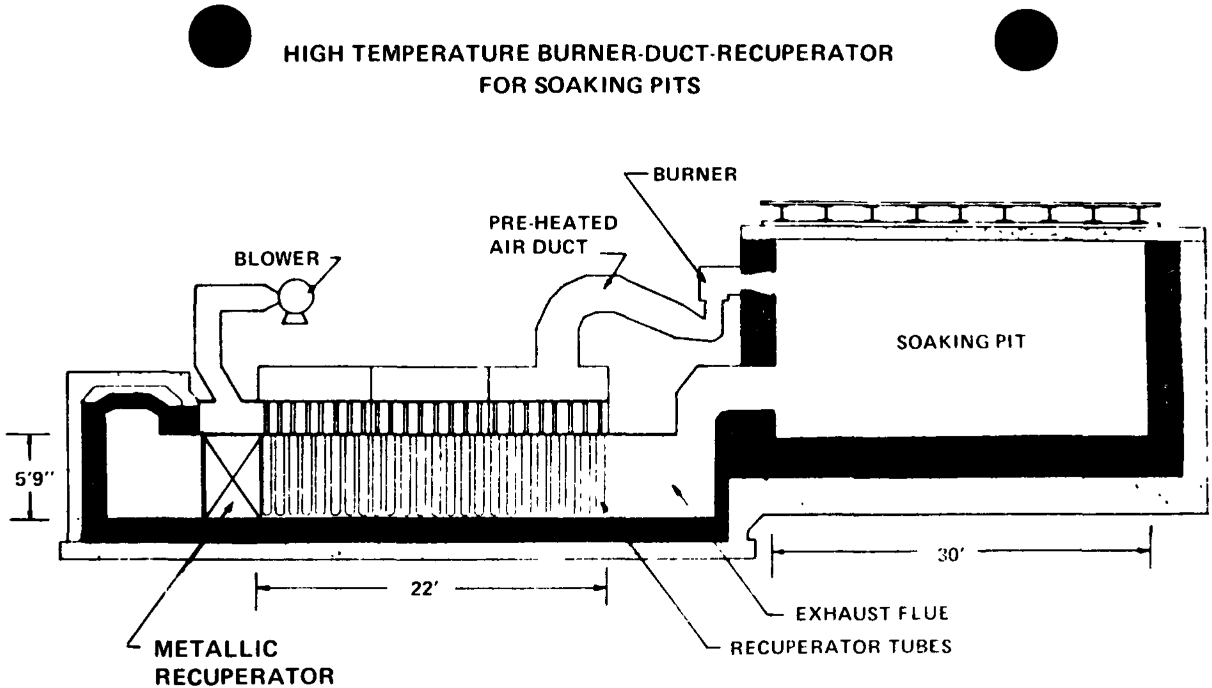

Figure 5. Schematic of Three Pass Ceramic Recuperator Interfaced Between the Metallic Recuperator and the Soaking Pit

	Item	Specification
1.	Number of Passes	3
2.	Number of Tube Assemblies/Pass	50
3.	Total Number of Tubes	
	Inner	150
	Outer	150
4.	Tube Array in Pass	5-4-5 (6" centers)
5.	Tube Dimensions (in.)	
	Length, Outer Tube	76-7/8
	Length, Inner Tube	96
	Wall Thickness, Both	1/4
	Gap Between Tubes	3/8
	Outer Tube O.D.	3-1/2
	Inner Tube O.D.	2-1/4

Table 1. HTBDR System Specifications

	High Fire	Low Fire
Air Side		
Existing Recuperator	10.0	0.8
1st Ceramic Stage	8.8	0.7
2nd Ceramic Stage	12.3	1.0
3rd Ceramic Stage	15.9	1.3
Plenums	3.0	0.3
Burner	14.0	1.2
TOTAL	64.0	5.3
Flue Side		
Existing Recuperator	0.5	0.04
1st Ceramic Stage	0.4	0.03
2nd Ceramic Stage	0.3	0.03
3rd Ceramic Stage	0.3	0.03
TOTAL	1.5	0.13

Table 2. Summary of Pressure Drop Analyses (in. WC)

A summary of the temperature distribution through the air side and flue side systems is shown in Figure 6 for the low fire (highest temperature) condition using an average inlet flue gas temperature of 2250°F. The temperature range shown in each schematic above the figure represents the expected temperature variation from the coolest to the hottest tube row in each pass. It will be seen that at an average inlet flue gas temperature of 2250°F and an incoming air temperature of 500°F from the metallic recuperator, the air outlet temperature of the burner is predicted to be 1860°F for a system operating effectiveness of 80+%.

MATERIALS CHARACTERIZATION AND SELECTION

The selection of the ceramic materials for the HTBDR fell into two categories: tubes and seals. The approach used to select the materials was to: determine the material characteristics required for the application, canvas material suppliers for candidate materials, determine material properties pertinent to the application and evaluate materials after exposure to simulated operating conditions. The availability of required shapes and sizes and costs were also considerations for materials selection.

For the outer tubes the key requirements were: resistance to erosion and corrosion by contaminants in the flue gases, good thermal shock characteristics, low permeability, and sufficient strength to survive mechanical and thermal stresses. The inner tube concerns were more directed towards the latter three requirements since the inner tubes are not exposed to the flue gases. The materials selected for the tubes were thus limited to silicon carbide (SiC) products which were known to possess the qualities for the application requirements.

Eight candidate SiC tube materials from two suppliers were evaluated in a flue gas exposure test at the evaluation site. The tube specimens were exposed for thirty-six days of continuous operation and were located in the flue immediately adjacent to the soaking pit. Table 3 lists the materials put in the flue exposure test. The specimens were examined after the exposure test and compared to the pristine material.

All SiC specimens were glazed on the exposed surfaces and all specimens had nodules on the surface which faced the soaking pit. Bombardment from particulate matter in the flue gas and/or reaction between the tube and the flue gas contaminents (possibly enhanced by the large radiation of the furnace seen by the specimens on one side) is suspected to have formed the nodules. Specimens shielded from direct impingement of the flue gases did not have any nodules on the surface. To minimize or eliminate the

Vendor	Type SiC
A	Siliconized Sintered Si_3N_4 Bonded Si_2ON_2 Bonded Oxide Bonded
B	Slip Cast Sintered α Extruded Sintered α Extruded and Siliconized

Table 3. Silicon Carbide Materials Evaluated In Flue Gas Exposure Test

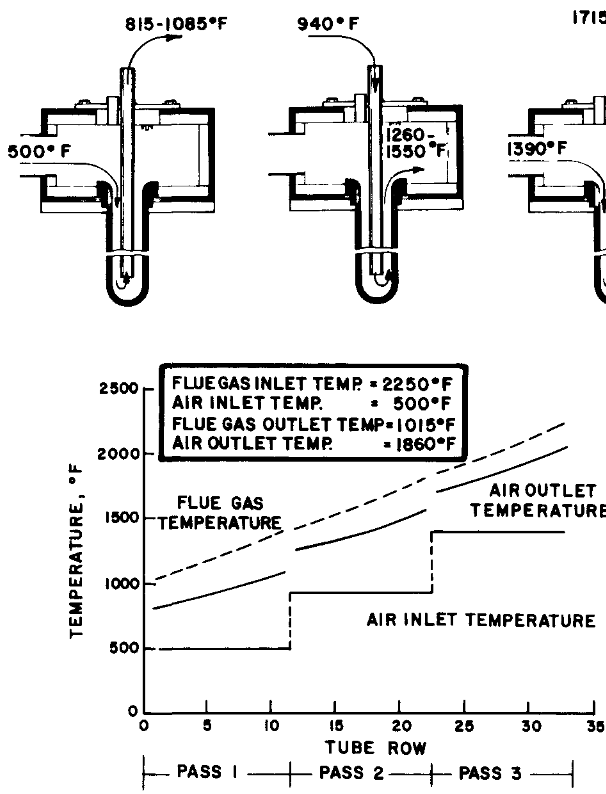

Figure 6. Predicted Temperature Distribution Within the Ceramic Passes of the HTBDR System - Low Fire Conditions, Flue Gas Temperature = 2250°F

formation of nodules on the two leading tube rows, a zircon ($ZrSiO_4$) coating will be placed on the upstream side of the tubes.

From the tube materials evaluated two were selected as candidates for the outer tubes: a sintered α-SiC and a siliconized SiC, both of which were virtually unaffected in the exposure test. The siliconized SiC from Vendor A was selected as the outer tube material for prototype testing due to production availability and costs. The sintered SiC from Vendor A was selected as the inner tube material for the same reasons. Due to the permeable nature of the inner tube material, a SiO_2 type coating will be placed on the tube to reduce permeability and to prevent passive oxidation at operating temperatures. Figure 7 shows the inner and outer tubes used in the prototype test, and Figure 8 shows the tubes assembled as an element in a device used to check tube-tube alignment.

The strengths of the candidate tube materials were also measured before and after flue exposure testing to evaluate strength changes compared to the tube stresses predicted from finite element stress analyses. Table 4 summarizes the strength testing of the two SiC materials selected for prototype testing. It will be noted that the SiC tubes showed little change in physical properties after flue exposure testing and that both materials had more than adequate strength to withstand the projected stresses.

The required characteristics of the seal material for use in the recuperator were:

- Low leakage between plenums and between the lower plenum and flue
- Compliance to accommodate the differential thermal expansion between the SiC tubes and the metal tube sheet
- Rigidity to prevent flow induced vibration of the tubes
- Stable at 2000°F

Since compliance and rigidity in a ceramic fiber product are opposing qualities, a dual sleeve-seal design was developed for the tubes as shown previously in Figure 4. The sleeve was prepared from a pressed ceramic fiber board (65-70 lbs/ft density) and was used to seal as well as prevent flow induced vibrations. The seal was made from a ceramic fiber insulating paper product which was meant to conform to the tube shape under pressure. Both materials were found to have acceptable leakage characteristics during testing at

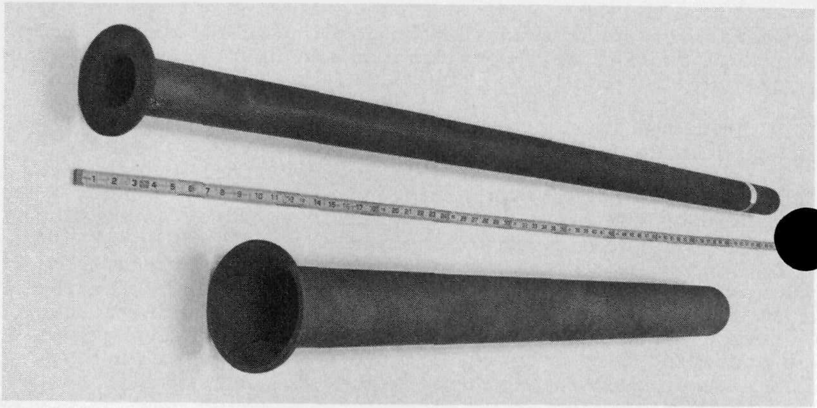

Figure 7. Comparison of the Inner (Top) and Outer (Bottom) Tubes Used in the Prototype Tests

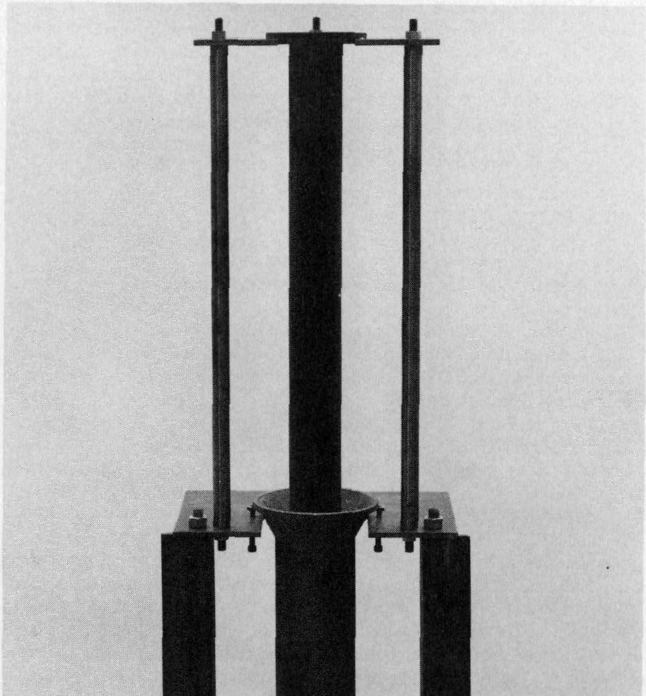

Figure 8. Relative Position of the Inner Tube and the Outer Tube Held In Place By Tube Alignment Fixture

	Outer Tube	Inner Tube
Maximum Predicted Stress (psi)		
Seal Region	3190	3800
Along Tube Length	4530	3440
Measured Tube Strength (psi)		
Modulus of Rupture, 70°F		
Exposed	31200	20400
Unexposed	32700	17100
Modulus of Rupture, 2370°F		
Exposed	29200	20100
Unexposed	30200	16100

Table 4. Comparison of Predicted and Measured Strengths of SiC Tubes Selected for Prototype Testing

Oak Ridge National Laboratories (Dr. George Wei). Linear shrinkage and strength tests, creep measurements and Young's Modulus determinations were performed at temperatures of 1200 and 2000°F on the pressed board and paper materials.

At 2000°F the shrinkage of both materials was less than 2% and the paper type product remained flexible and the pressed board remained rigid. Table 5 summarizes the Young's Modulus data which verified the characteristics of the materials after shrinkage testing. The 100 hr static creep test using a 30 psi load at 2000°F showed that the pressed board had a creep rate of $4x10^{-6}$ in/in/min after an initial deformation of 6.0% due to temperature induced binder changes. This creep rate was deemed acceptable.

PROTOTYPE TESTING

Phase 1 of the project included the design, construction and testing of a prototype recuperator. The purpose of the prototype test was: to verify the pressure drop and heat transfer models developed for the project, to evaluate the system leakage and to evaluate the ceramic fiber products and SiC tubes selected for the recuperator.

The prototype recuperator consists of six tube assemblies arranged in a hexagonal pattern and a tube assembly in the center. The prototype design was essentially built to scale except for the quantity of tubes and the lengths of the tubes which were reduced 30" from that shown in Table 1. Set in a simulated flue, the air side system of the recuperator was connected to an air preheater system composed of a series arrangement of a metallic recuperator located in the flue and an electric air preheater. A large gas kiln was used to provide hot flue gases for the flue side system.

Pressure drop and leakage testing was done at room temperature. The system leakage was assessed by pressurizing the recuperator and measuring the flow needed to maintain system pressure. An air flow of 1100 SCFH was required to maintain a system pressure of 35 in. of H_2O which is equivalent to a 0.375 inch diameter hole. The leakage measured was a combination of leakage through the seals and leakage out the system through cracks, etc., and was considered to be small.

The pressure drop testing was done under the following conditions: using air flow up and down the center tubes, using only the center tube assembly with the other assemblies plugged, using all tube assemblies open, and using varying mass flow rates. Compressed air and a fan were used as the sources of air. Figure 9 shows the pressure drop data from the prototype test compared to the predicted

Material	Temperature (°F)	Young Modulus (10^3 psi)
Paper	1200	0.8
Pressed Board	1200	10.5
Pressed Board	2000	8.9

Table 5. Young's Modulus of the Ceramic Fiber Paper and Pressed Board Measured at Temperature

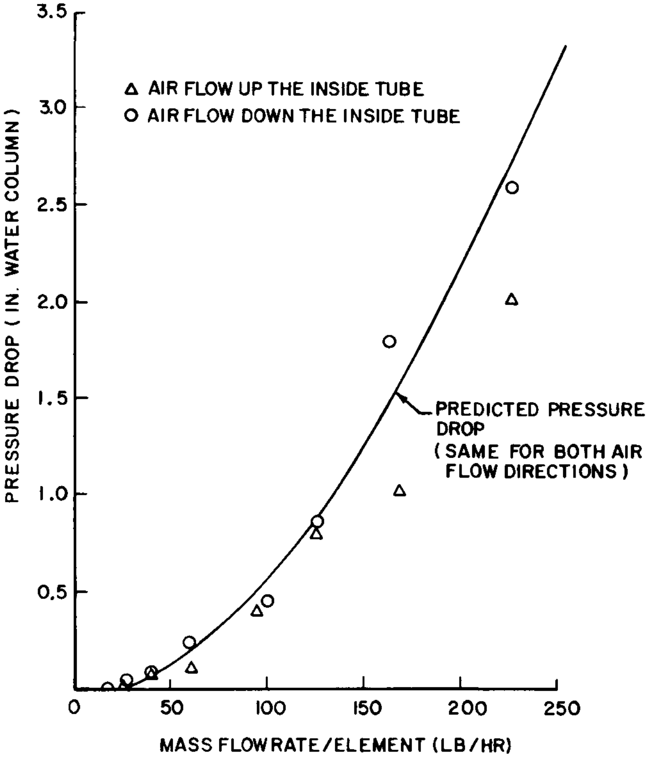

Figure 9. Comparison of Predicted and Measured Pressure Drops From the Prototype Test With All Tube Assemblies Open

pressure drop for both air flow directions with all tubes open. It will be noted that good agreement was found between the measured and predicted pressure drops. Similar agreement in predicted and measured pressure drops was found with the center tube assembly open and the other six tube assemblies closed.

Verification testing of the heat transfer model was done by measuring the air inlet and air outlet temperatu of the recuperator under conditions which included varyi the following parameters: flue gas temperature, air inlet temperature, flue side mass flow rate, air side mass flow rate and air flow direction in the tubes. It was necessary to examine all of the preceeding variables with the prototype to adequately measure thermal performance since each stage of the recuperator will be exposed to different conditions during normal soaking pit operation. Figure 10 compares the predicted versus measured thermal performance of the prototype. Since the heat transfer model was based on no heat loss through the system (e.g., plenum walls, tube sheet cooling, etc.), the measured values have to be corrected for system heat losses. It will be seen that this corrected data compares well to the predicted data.

Thermal performance evaluation at other air inlet temperatures produced similar results for air flow up the center tube. However, when the air flow direction was reversed (air flow down the center tube), the measured thermal performance was better than predicted by the model.

SUMMARY

A ceramic recuperator has been designed by Babcock & Wilcox to deliver 1800°F minimum preheated combustion air to a high temperature burner. The pressure and heat transfer models developed in the design phase have been experimentally verified under ambinet conditions for flue temperatures up to 2000°F and air inlet temperatures up to 1425°F. System leakage has also been determined to be small. Further prototype testing will be conducted at flue temperatures up to 2350°F. Pressure testing will be redone after all high temperature tests have been completed to determine if the prototype has changed as a function of time. The ceramic materials used in the prototype will also be examined for deleterious effects after completion of the prototype tests.

Prior to project continuation into Phase 2, the following items are to be completed:

- Demonstration of the burner
- Completion of analysis of all technical efforts

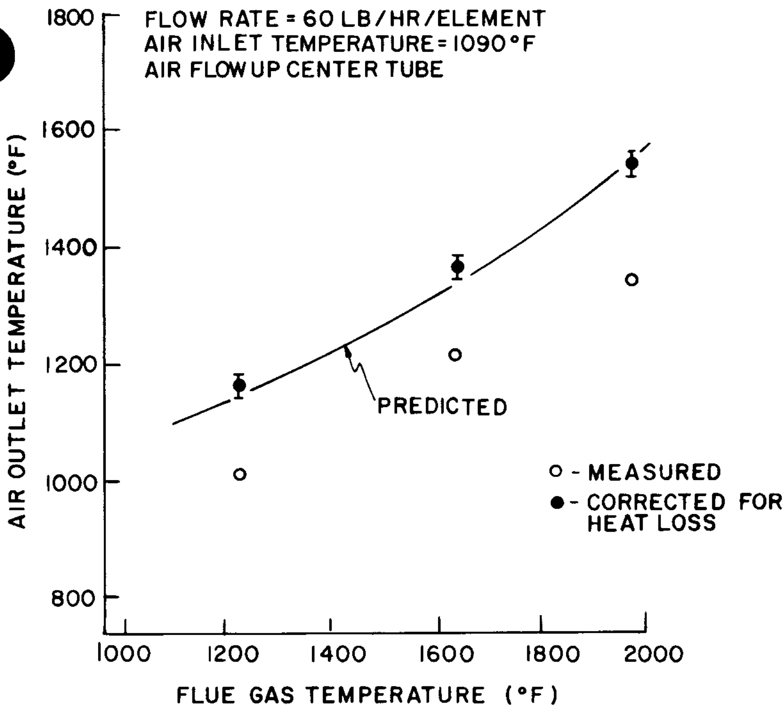

Figure 10. Thermal Performance of the Prototype Recuperator at 1090°F Air Inlet Temperature. Comparison of Predicted and Measured Temperatures.

- Evaluation of all prototype test results
- Reassessment of thermal performance
- Modification of design if necessary
- Evaluation of system economics

Detailed design documents will be available from D.O.E. or NTIS at the completion of Phase 1.

ROLE OF UTILITIES IN DEMONSTRATING ELECTRIC VEHICLE TECHNOLOGY

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INTRODUCTION

It is incumbent upon all energy-related utilities to continually explore newly emerging technology to assess its potential for increasing operating efficiency, decreasing operating expense, and ensuring a sufficient supply of energy when needed. This paper examines one such technology, the electric road vehicle (EV), which is being evaluated by many electric utilities for these reasons and by gas and telephone utilities for their own fleet use. To fully understand the extent of these companies' involvement, it is first necessary to examine the conditions which brought about the modern emergence of the electric vehicle.

HISTORICAL PERSPECTIVE

Of the 4200 autos sold in the United States in 1900, 38 percent were electric, and electric cars and trucks continued to be used extensively through the next 20 years by industry, commerce, and private individuals. But with the exception of the Curtis Publishing Company's fleet of 22 electric trucks, some of which ran continuously for over 50 years in Philadelphia through 1962, electric vehicles ceased to be a viable transportation option next to higher-powered unlimited-range internal combustion engine vehicles fueled by a seemingly unlimited supply of gasoline.

Interest in electric transportation was renewed in the 1960s during the period of national focus on air pollution. Over the preceding 50 years, the number of passenger cars in the nation had increased by 75 million, and these vehicles were identified as a major contributor to the urban pollution problem. Various studies comparing ground-level pollutants indicated that a decided improvement could be made by the use of electric motor transport in high-density urban environments using energy supplied by more efficiently controlled centralized power plants. In 1966, during hearings examining proposed amendments to the Clean Air Act, Congress suggested a partnership between government and the electric utilities in developing and demonstrating electric vehicle technology. Many electric utilities tested prototype EVs during the late 1960s and early 1970s, including 107 multi-stop minivans operated by 61 electric utilities and water companies in a program coordinated by the Electric Vehicle Council.

Emphasis on electric vehicle development intensified in 1973 following the oil embargo. In recognition of this dependence, coupled with the rapidly increasing cost of imported oil, Congress moved quickly to enact Public Law 94-413, "The Electric and Hybrid Vehicle Research, Development, and Demonstration Act of 1976." In its findings, Congress declared that "the Nation's dependence on foreign sources of petroleum must be reduced, as such dependence jeopardizes national security, inhibits foreign policy, and undermines economic well-being." The Act seeks to accelerate the advancement of electric and hybrid vehicle technology and to place vehicles in demonstration for testing and evaluation in private, commercial, industrial, and governmental fleets. This critically important ongoing program is administered by the Department of Energy (DOE).

Electric vehicle component and system technology has advanced significantly under the federal program. However, progress has recently slowed because of federal budgetary cutbacks during a recessionary period when private industry, most notably battery manufacturing, was experiencing financial setbacks, resulting in the abandonment of several advanced battery system projects.

UTILITY EV FLEETS

Estimates of the total number of electric road vehicles currently in operation in industrial, commercial, and private use in the United States vary from 1500 to 2500. There are approximately 895 cars, vans, and trucks being operated by site operators in 32 states in the DOE program. Table I gives a breakdown of public sector (federal, state, and local government and universities) and private sector (industrial and commercial) operations.

Table I

DOE TEST AND EVALUATION SITE OPERATIONS

Sector	Vehicles	Site Operations	Operational Locations	States
Public	447	25	60	27
Private	448	16	29	17

An indication of the extent to which utilities have been involved in operating and testing EVs since 1976 is shown by a recent Philadelphia Electric Company survey summarized in Table II. Included are 21 electric and combined electric and gas companies, four telephone companies, one gas company, and one railroad. Of these, 15 have been or are involved with the DOE program. In addition to the electric utilities shown, many others have made related studies or have operated vehicles prior to the period accounted for in Table II. The large telephone corporations are evaluating electric vehicles for their cost-saving potential, as is the U.S. Postal Service, which has utilized 416 vehicles since 1976 and has 394 in operation at present.

TECHNOLOGY - DEVELOPMENT AND ASSESSMENT

Most of the electric vehicles in use today are converted vehicles designed to utilize internal combustion engines. Some of them contain advanced electrical components and batteries, but they do not have the advantages of the idealized mechanical power trains (such as continuously variable transmissions and motorized transaxle concepts) and unified battery compartments that could be incorporated in vehicles built from the ground up. The economy of mass production will afford designers the opportunity of using advanced mechanical as well as electrical components and battery systems.

Typical of current production are the converted lead-acid battery-powered vehicles shown in Figure 1. As part of Philadelphia Electric Company's EV fleet, they have the following nominal operating characteristics:

Range:	35 to 50 miles, depending on speed and terrain
Top speed:	55 mph
Acceleration:	0 to 30 mph in 13 seconds
Energy use:	0.75 ac kWh/mile

Table II

UTILITIES INVOLVED IN OPERATING AND TESTING ELECTRIC VEHICLES

Company	Number of Vehicles Used/Tested Since 1976	Number of Vehicles Presently In Use	DOE Site Operator	Note
Arizona Public Service Company	23	21	Yes	
AT&T	47	0	Yes	(1)
CENTEL Corporation	20	7	Yes	
Consolidated Edison Company	50	13	Yes	(2)
Detroit Edison Company	32	29	Yes	
Green Mountain Power Corporation	1	1	No	
GTE Corporation	170	170	Yes	(3)
Lincoln Electric System	7	7	Yes	
Long Island Lighting Company	75	49	Yes	(4)
New England Electric	3	0	No	
Niagara Mohawk Power Corporation	4	4	Yes	(5)
Pacific Gas & Electric Company	2	2	No	
Pennsylvania Power & Light Company	2	0	No	
Philadelphia Electric Company	20	20	Yes	
Potomac Electric Power Company	3	1	No	
Public Service Electric & Gas Company	2	1	No	
Puget Sound Pow[illegible] Light Company	1	0	[illegible]	

Southern California Edison Company	11	0	No	(6)
Texas Electric Service Company	3	0	No	
TVA	38	21	No	(7)
Wisconsin Electric Power Company	3	3	No	
Wisconsin Power & Light Company	1	0	No	

(1) Includes 35 vehicles operated under DOE contract.

(2) Contract with DOE expired in June 1982.

(3) Includes fleets ranging in size from 10 to 25 vehicles each, located in Lakewood, California; Tampa, Florida; Honolulu, Hawaii; Bloomington, Illinois; Lexington, Kentucky; Durham, North Carolina; Marion and Bowling Green, Ohio; Tigard, Oregon; Erie, Pennsylvania; Irving, Texas; and Everett, Washington.

(4) Includes 64 vehicles administered by LILCO and operated under DOE contract, including, in part, four each at Brooklyn Union Gas Company and Southern New England Telephone Company, and two each at New York State Electric & Gas Company, Long Island Railroad, and Rockville Center (municipal electric company).

(5) Operating four vehicles under subcontract to New York State ERDA, a DOE fleet operator.

(6) Includes 10 leased vehicles tested for the Electric Power Research Institute (EPRI).

(7) Includes 11 vehicles tested for EPRI.

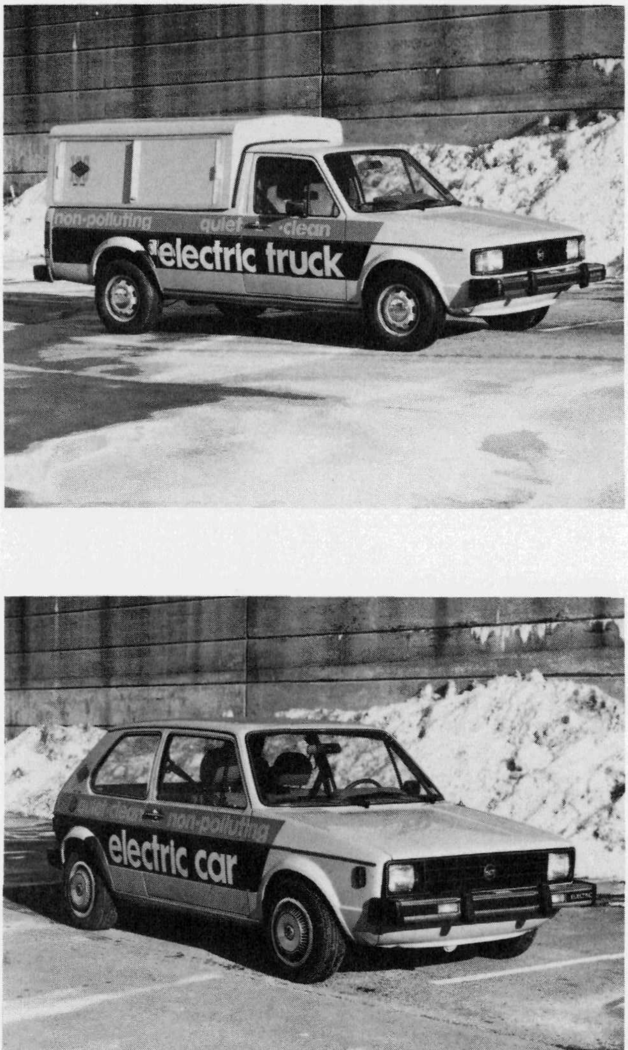

Figure 1.

Electric Vehicles Used by Philadelphia Electric Company

Because the state of the art is well in advance of the state of production, it is particularly important for those making vehicular assessments to participate in the developmental process. Through their membership in the Edison Electric Institute, investor-owned electric utilities support the Electric Vehicle Council's activities including resource and technology transfer and the management of international EV symposia and expositions. Many electric companies also support electric vehicle technological development, assessment, impact studies, and information exchange through their support of the Electric Power Research Institute (EPRI).

EPRI's major effort is directed at advanced battery development. In addition to assessments of advanced lead-acid systems, which are still considered by many to be a viable and cost-effective component for vehicles requiring ranges of 40 to 80 miles, EPRI is also assessing nickel-iron, nickel-zinc, and zinc-chloride battery systems. EPRI is negotiating contracts with Argonne National Laboratory and the Jet Propulsion Laboratory for assessments of battery performance, cycle-life, and optimized operating cell temperature. Under contract to EPRI, the Tennessee Valley Authority (TVA) is evaluating EV components including range meters, defective battery module detection devices, advanced battery chargers, and battery thermal management systems.

TVA operates an electric vehicle test facility near Chattanooga, Tennessee, which includes a 9600 sq. ft. passive solar building and an adjoining one-mile test track (Figure 2). The extensively equipped facility was constructed in 1981 to accommodate the needs of TVA's own electric vehicle test and demonstration program as well as contractual work for EPRI and others. Some of the EPRI work at TVA is complemented by independent studies by other utilities such as the battery charger harmonic assessments pursued by New England Electric, Philadelphia Electric Company, and Detroit Edison (the latter under separate contract to EPRI). In 1981, Detroit Edison opened the first modern-day electric car service center devoted exclusively to the maintenance and study of its EV fleet (Figure 3).

OFF-PEAK POWER

Electric generation and transmission facilities are sized to match peak regional demands. Recharging electric vehicles during periods of minimum electric consumption enables utilities to utilize idle capacity, thereby providing all of their customers with the economic benefits of increased system load factors. Many electric utilities offer rate incentives for off-peak consumption, including

Figure 2. TVA Maintenance and Testing Area (Insert: One-Mile Test Track)
Courtesy of Tennessee Valley Authority

Figure 3.

Electric Car Service Center
Courtesy of The Detroit Edison Company

rates that can be utilized for off-peak residential electric vehicle charging.

COLLECTIVE ACTION

Major automobile and truck manufacturers and electric utilities are the critical elements in the path to mass-produced cost-effective electric vehicles and their necessary supporting operational infrastructure. In 198[illegible] several meetings took place between representatives of the utility industry and General Motors to define the issues of importance to each regarding eventual EV production. Such a continuing dialogue will serve to accurately delineate such topics as the regional costs and availability of electricity, the parameters for advanced battery designs, and the requirements for battery chargers and utility system interfacing.

Additionally in 1982, several utilities undertook the formation of a consortium representing the utility industry and related industries with the intent of bringing about the near-term production of electric road vehicles in quantity by major and independent auto/truck manufacturing companies.

CONCLUSION

Facing a future of uncertainty concerning the cost and availability of petroleum-based fuels, it is essential that we examine all feasible alternatives. It is quite probable that our future mobility will be contingent upon the development of an integrated transportation system utilizing various fuels and mission-designed vehicles. The electric vehicle can be a viable component of that system, serving driving requirements up to 100 miles or more and utilizing the flexibility of utility fuel sources--coal, hydro, nuclear power. Further, electric vehicles can help achieve the related goals set by Congress--improved air quality and a significant reduction in petroleum imports. The utility industries have a vital role to play in this important process.

ELECTRIC VEHICLE TEST AND EVALUATION DATA: PRELIMINARY ANALYSIS

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The data in this paper summarizes the current experience of DOE private sector site operators and is based on information gathered from electric vehicle (EV) private sector site operators by Booz, Allen and Hamilton under contract to the U.S. Department of Energy. Since January 1980, Booz, Allen has collected and computerized on an IBM Personnel computer data from 16 private sector site operators covering nine vehicle types and over 1.3 million miles of vehicle travel. The paper summarizes key indicators of vehicle performance including energy consumption per mile and miles travelled per charge and reports on results of and plans for special analyses. More detailed information is available from the authors.

BACKGROUND

As a part of the implementation of the Electric and Hybrid Vehicle Research, Development and Demonstation Act of 1976 (Public Law 94-413, as amended by Public Law 95-238), the U.S. Department of Energy has sponsored the field testing and demonstration of electric vehicles by private and public sector site operators. In addition, research and development efforts in batteries and propulsion components as well as total vehicle systems are continuing. Vehicles currently in use by site operators are being updated selectively with advanced technology and tested to assess the capability of the vehicles to accomplish practical work functions.

The goals of the Test and Evaluation Branch include:

- The testing and evaluation of EV's being used by site operators
- State-of-the-art testing of vehicles and components available to site operators and the introduction of improved technology components (including batteries and subsystems) into engineering and site operator vehicles for engineering tests
- Maintenance of an EV data base and dissemination of EV test and technology improvement results.

This paper is one step in continuing efforts to achieve this third goal. The data in this paper summarizes the current experience of DOE private sector site operators. We are seeking to share this information with other interested parties to help identify and ultimately to test nearer term product improvements. Because of space limitations, however, we are only able to present a sampling of the information which is available. More information on the results of the EV test and evaluation program is available from sources (1) and (2) and can be obtained by contacting the authors.

Other sources of in-field EV performance data include the Tennessee Valley Authority (TVA), Chattanooga, Tennessee, working with the Electric Power Research Instititute (EPRI) and the U.S. Postal Service Research and Development Laboratories which is field testing three different vehicles (ten each) at three sites.

DATA BASE CHARACTERISTICS

The information presented in this paper is based on data gathered from EV private sector site operators by DOE's private contractor, Booz Allen and Hamilton Inc. Since January 1980, Booz Allen has collected and computerized on an IBM Personnel computer data from 16 private sector site operators covering nine vehicle types and over 1.3 million miles of vehicle travel. A summary of the 16 sites and nine vehicle types included in the data base together with the mileage travelled by vehicle site is shown in Table 1.

For each vehicle contained in the data base, the following information is available:

- Miles travelled and energy consumption between battery charges
- State of charge, before and after charging
- Days vehicle was scheduled for service but not used and reasons for being out of service

Table 1

Data Base Characteristics

Site	Vehicle Type	No. of Vehicles	Total Miles Traveled Per Site
Long Island Lighting Company	Jet 600 Van	12	
	Jet 1000 Van	1	
	Jet 750 Truck	1	
	Jet Electric	19	110,764
CON Edison	Eva Current Fare	20	90,764
AT&T	GMC Van	40	278,208
WED Enterprises	Jet 1000 Truck	7	20,884
GTE Service Company	Jet 600 Van	25	
	Jet 750 Truck	127	
	Jet Electric 007	12	479,457
Rockville Center	Jet 600 Van	2	10,548
Southern New England Telephone	Jet 600 Van	3	2170
Leviton	Jet 600 Van	1	4657
New York State Electric/ Gas Company	Jet 600 Van	1	2686
Arizona Public Service	Jet 1000 Van	2	
	Jet 1000 Truck	14	
	Jet Electric 007	3	71,046
Long Island Railroad	Jet 1000 Truck	2	8033
Southwest Research Institute	Jet 1000 Van	6	
	Jet 750 Truck	2	37,920
Village of Westbury	Jet 600 Van	1	58
Princeton University	Jet 750 Truck	1	308
Central Telephone	Jet 750 Truck	8	
	Jet Electra Car	2	
	Lectra Motors Truck	10	33,897
Detroit Edison	SCTR-1 Electric	24	149,835

- Maintenance actions identified by vehicle, type of action and part code number
- Drive identification number and information which defines the conditions under which the vehicle was operated, including temperature, payload, terrain and mission
- Battery charge cycles
- Vehicle descriptive information including vehicle manufacturer, battery type, charger type, vehicle weight and battery voltage.

Starting December 1982, however, only mileage, energy consumption, battery failure, repair and driver identification data will be collected on each vehicle to minimize the burden of data collection on site operators and to improve the quality of key data items. We are continuing to seek ways to minimize the overall data requirements imposed on site operators, to further focus the data collection on key parameters (such as the impact of battery life on EV performance and in general the testing of advanced technologies), and to assure the high quality of the data.

FINDINGS OF PRELIMINARY DATA ANALYSIS

The data described in the previous section have been used to date to support two types of analyses:

- Routine Analyses. The purpose of these analyses is to monitor program performance, measure progress and detect problem areas. They are on-going analyses whose results are reported to DOE on a quarterly basis.
- Special Analyses. The purpose of these analyses is to provide insights on specific issues of importance to improved EV operation and/or performance. They are analyses conducted as needed in support of engineering evaluations an field experimentation or in response to inquires by interested parties.

Some of the key findings of these analyses are presented below. Before reviewing these findings, however, several observations should be made on what the preliminary data can and cannot show:

- Aggregate comparisons and generalizations should be avoided or at least the necessary caveats must be recognized. The vehicles being tested often differ in type, technology, battery, utilization, and maintenance. The driver of the vehicle may also vary. For example, for the same vehicle use, the best drivers often obtain over 50 percent better performance then even the average driver with significantly lower maintenance costs. The same vehicles at the same site can differ significantly because of varying mission characteristics, the use of different charging approaches and/or different type batteries.

- The vehicles being tested by site operators were commercially available from EV manufacturers at the time that they were purchased and had to meet DOE performance standards to be included in the demonstration. Thus, the data represents the current state-of-the-art of a fleet basically placed into service between 1980-1982. Advancement of the state-of-the-art in electric and hybrid vehicles continues under DOE sponsored development and others in the private sector. The results presented here do not assess the performance of these vehicles.

Routine Analysis

The focus of the routine analyses performed by Booz, Allen and Hamilton is on computing various indicators of EV performance and utilization and reporting the results of these analyses to DOE and site operators. As mentioned earlier, the primary purpose of these analyses is to provide DOE with an indication of program progress. However, in addition to this purpose, site operators have also found them useful in gauging their individual performance.

In all, five indicators are continually computed, analyzed and reported on by Booz, Allen in their quarterly report of private sector site operations. The five indicators are:

- Kwh per mile
- Kwh per mile adjusted by vehicle weight
- Miles travelled per charge
- Miles travelled per vehicle per month
- Labor hours per mile.

With the exception of Kwh per mile, each of the above indicators are analyzed both by vehicle type and site. The first indicator -- Kwh per mile -- is analyzed by vehicle type only.

The following is a summary of some of the key findings from analysis of these indicators. For more detail, the reader is referred to reference (3) at the end of this paper.

- Over the period January 1981 through September 1982, we found that vehicle energy consumption adjusted for weight (i.e., Kwh per mile per 1000 pounds) increased slightly for the program as a whole (see Figure 1). We also found that there was considerable variation in vehicle energy consumption by site, which we attribute to the different operating practices and commitment to the program of different site operators. For example, as shown in Figure 1, AT&T has been able to steadily reduce vehicle energy consumption since January 1981, while vehicles at both GTE and Detroit Edison have shown a gradual increase in energy consumption. We attribute this difference in vehicle performance in part to the commitment AT&T has made to the program over the years in making product improvements (e.g., charger efficiency improvements, addition of regenerative braking).

- Over the period January 1981 through September 1982, we found that vehicle utilization declined for the program as a whole (see Figure 2). The persistent downward trend shown in Figure 2 is not surprising, however, in view of the many operating and maintenance problems (e.g., battery failures, battery maintenance problems, etc.) that many of the vehicle site operators have encountered. We also found a large variation in the miles travelled per vehicle by site as was the case in vehicle energy consumption adjusted for vehicle weight. As shown in Figure 2, GTE and Long Island Lighting have both slightly decreased the utilization of their vehicles over time, while AT&T has sporadically but gradually increased their vehicle utilization.

- Finally, we have found that the miles travelled per vehicle between charges (with some variation) has remained relatively constant over time for the program as a whole (see Figure 3). Again, as

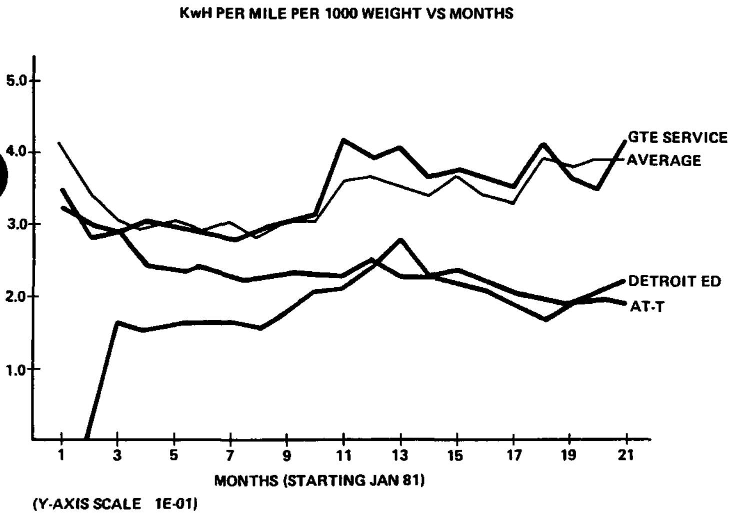

FIGURE 1
Kwh Per Mile Per 1000 Pounds by Site by Month

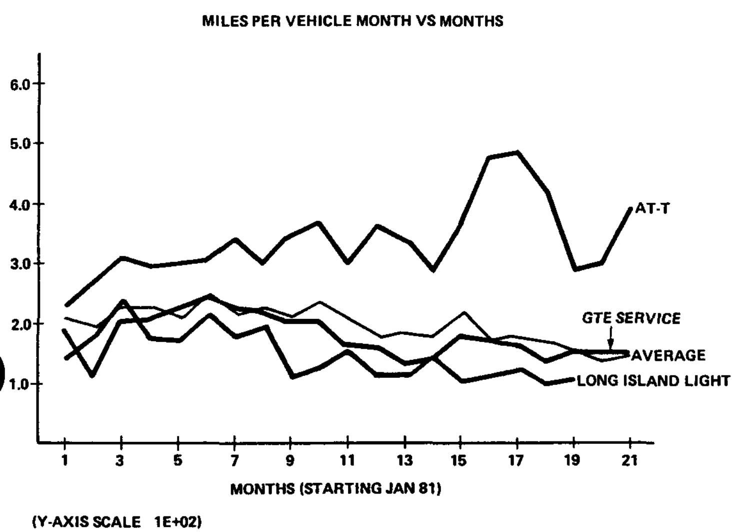

Figure 2
Miles Travelled Per Vehicle by Site by Month

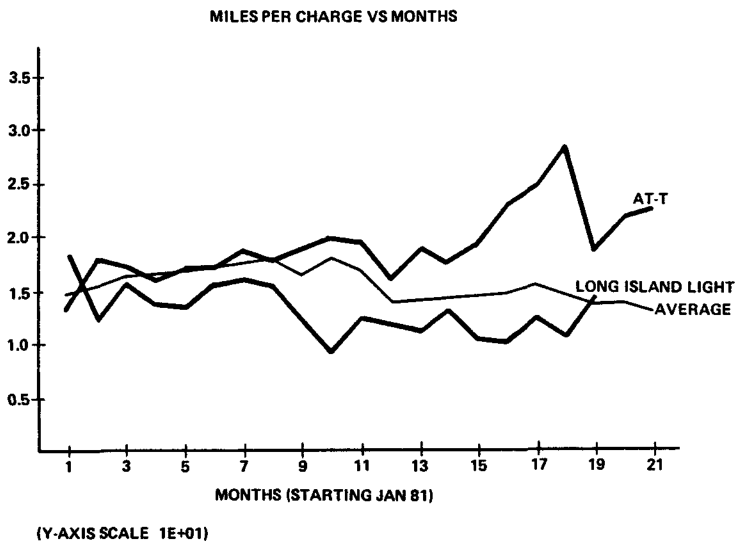

Figure 3
Miles Travelled Per Charge by Site by Month

was the case in the previous two figures, there exists considerable variation in miles travelled per charge by site.

Special Analysis

As mentioned earlier, one of the goals of the EV Test and Evaluation Program is to disseminate information which will aid operators, administrators, manufacturers, suppliers, policy makers, scientists and engineers adva the state-of-the-art of electric vehicles. In line wit this goal, the DOE has recently developed a program designed to utilize all the information being collected by DOE contractors and site operators. Very simply, the program requires that DOE's prime contractor, Booz, Allen and Hamilton, select, analyze, and disseminate (every two to four months) the results of analyses performed (using data collected as part of the EV Test and Evaluation Program) on topics of concern to the EV community.

To date, two reports have been completed by Booz, Allen, and one is in progress. The focus of these first three reports has been on testing the quality of the data being received from site operators in the private sector by analyzing generally accepted industry hypotheses regarding factors affecting electric vehicle energy consumption. In all, seven hypotheses have been tested and while not all hypotheses have been confirmed, the results of the analyses do suggest that the data being received by private sector site operators are of sufficient quality to perform subsequent more detailed analyses. Those hypotheses which were supported by the data base are as follows:

- Energy consumption per mile increases as vehicle weight increases
- Energy consumption per mile is affected by climate and is lower in warmer temperatures than in colder temperatures
- Energy consumption per mile decreases as mission length increases
- Energy consumption per mile increases as battery age increases
- Energy consumption per mile increases as the number of stops/starts per mile increases.

Of particular interest was the confirmation of the hypothesis that energy consumption per mile decreases as mission length increases. This hypothesis was based on the belief that the longer the mission length, the deeper is the discharge of the battery, and the deeper the battery is discharged, the more efficient is the charge. Thus, it was believed that vehicles which travelled greater distances between charges would be more energy efficient.

The effect of mission length on energy consumption was analyzed by reviewing energy consumption statistics for 25 Jet 750 vans operating at GTE California. Only these vehicles were investigated to eliminate the effects of vehicle weight and climate (California's temperature is relatively constant throughout the year) on energy consumption.

In carrying out the analysis, the following activities were performed:

- The average monthly energy consumption of each vehicle was computed and plotted against the average daily mission length of the vehicle during that month

- A regression analysis was performed to determine the relationship between mission length and energy consumption.

Average daily mission length was computed as the total miles travelled by the vehicle in the month (as reported by GTE) divided by the total number of days the vehicle was operated. The results are shown in Figure 4.

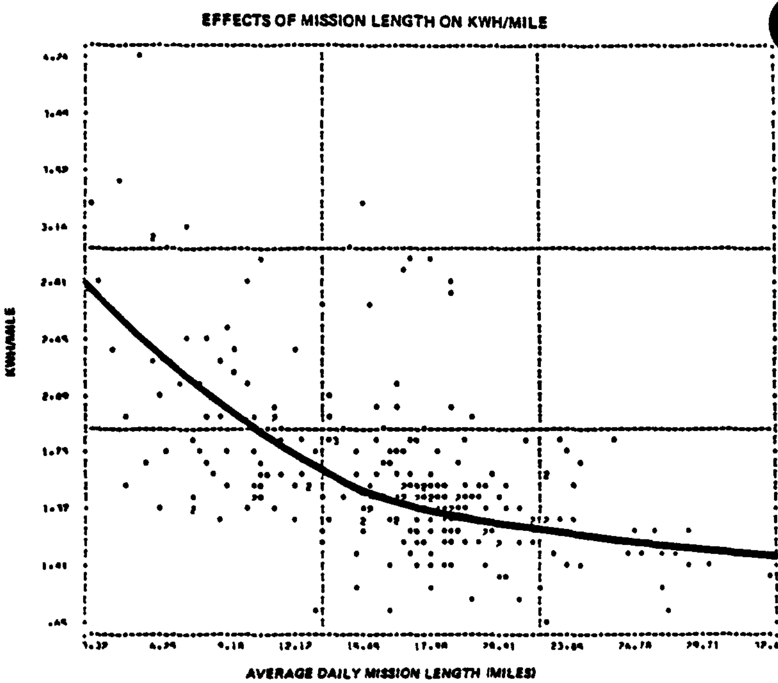

Figure 4
Energy Consumption Per Mile Vs. Mission Length

As shown, while not linear, energy consumption does decrease as daily mission length increases, as hypothesized. Furthermore, the intercept and slope of this curve were both significant at the 99 percent confidence level indicating a high degree of confidence in the direction of the curve.

Future plans for topical analyses include:

- Comparing the performance of vehicles at private sector sites with those at public, state and local government sites and other private testing programs when available

- Using the private sector site data base to compute a baseline which will allow comparisons between vehicles which incorporate advanced technologies and those which do not, as part of an ongoing DOE program to test new product improvement areas.

NEXT STEPS

In 1981, a site operators users' task force was established to inform industry representatives and EV researchers of the problems experienced at the sites, and to obtain recommendations for developing solutions. As a result of this initiative, site operators have prepared cost-sharing proposals for equipment and instrumentation improvements that promise performance improvements and reduced maintenance requirements in the near term. Testing these improvements will help us considerably in evaluating the impact of these improvements which respond to major EV problems identified by the task force.

Proposals were received in the following nearer term product improvement areas:

- Improved batteries--advanced lead acid and nickel zinc batteries
- Advanced battery chargers
- Off-board battery capacity test equipment
- Improved state of charge meters
- Auxilliary battery management systems
- Transitorized controllers
- On-board battery performance monitoring systems
- Battery watering instruments.

Contract modifications are currently underway and should be completed by April 1, 1983, to allow testing of these nearer term product improvements. As results from the Advanced Technology Testing effort at DOE become available, they will be assessed to determine the desirability of site testing of promising new technologies for further vehicle improvements.

Close cooperation between the test and evaluation site activities and DOE's Advanced Technology Testing effort guide the need for and direction of government support to R&D and also speed up the transfer of product improvements into test vehicles. Private sector site operators also work closely with component and vehicle suppliers outside government sponsorship in closely monitoring, testing and improving vehicle components. The DOE current product improvement activities are designed to accelerate introduction of new technology into site operations; the results of this testing will be made available to interested parties as they become available.

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(1) Booz, Allen and Hamilton, Analysis of Factors Impacting Electric Vehicle Energy Consumption Per Mile, Topical Report No. 1, July 1, 1982.

(2) Booz, Allen and Hamilton, Analysis of Factors Impacting Electric Vehicle Energy Consumption and Efficiency, Topical Report No. 2, September 15, 1982.

(3) Booz, Allen and Hamilton, Quarterly Report of Private Sector Operations, Third Quarter 1982, December 15, 1982.

Part IV

TECHNOLOGIES FOR FOSSIL, NUCLEAR AND GEOTHERMAL RESOURCES

Higher prices continue to drive the development and use of new technologies for extracting, converting, transporting and using indigenous fossil, nuclear and geothermal resources. Each year the remaining energy resources are incrementally more difficult and more expensive to extract. As the cheapest and most convenient energy resources are used up, technologies are developed and used to convert less desirable energy forms (e.g., oil shale) into clean convenient forms (e.g., gasoline).

This section contains papers that examine significant progress in the technologies being developed and utilized for these resources.

COMMERCIAL OIL SHALE ACTIVITIES IN AUSTRALIA

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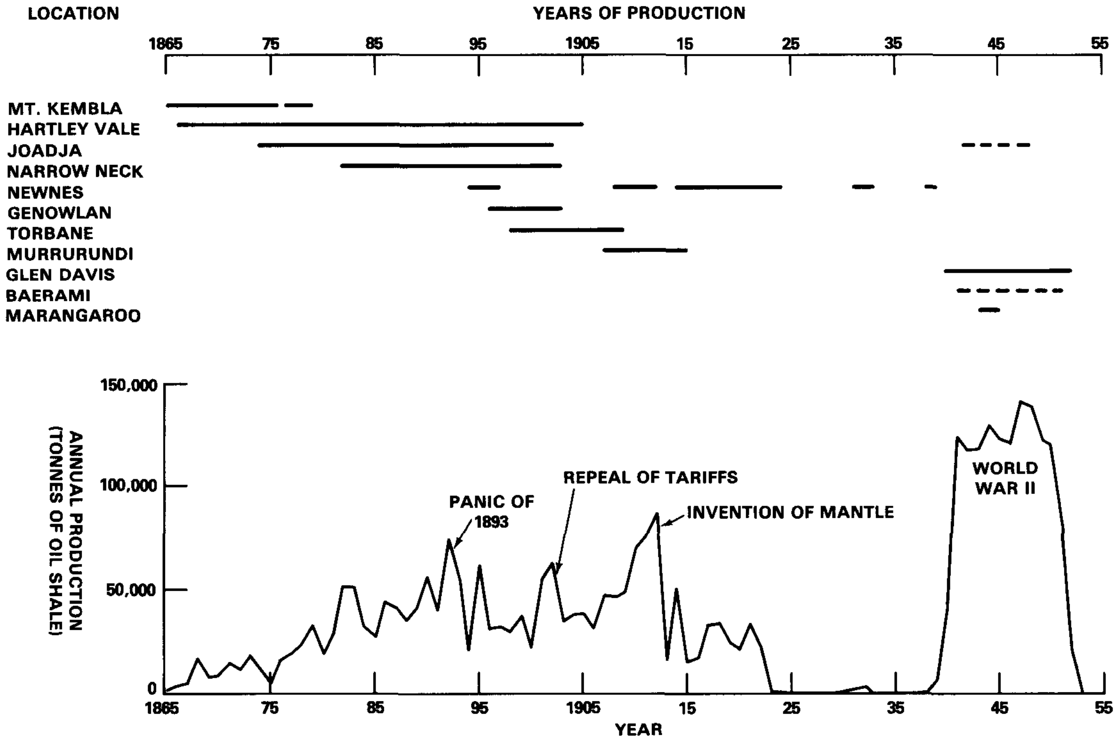
Office of the Deputy Assistant Secretary for
Oil, Gas, Shale and Coal Liquids

Oil shale was produced in Australia in all but seven years of the 87 year period from 1865 to 1952. Like every other aspect of Australian development, the oil shale industry was made possible by unique resources and the resourcefulness of the people of that continent. Exceptionally favorable circumstances for development occurred in 1865. World demand for rich torbanite or boghead shales to enhance the lighting value of water gas manufactured from coal grew just as the small deposit at Torbane, Scotland, which had been worked from 1852 to 1862 was exhausted. Samples of torbanite which existed close to sea ports in New South Wales were sent to the Paris Exposition in 1862 and it was discovered that a 5% addition of this unusually rich shale (180 gallons per ton) to coal would increase the luminosity of the resulting gas by a factor of six(1).* At the same time, newly discovered American petroleum was taking over world markets for liquid fuels except for Australia where the great shipping distance and state tariff policies made local production of shale oil profitable.

*See references at end of article.

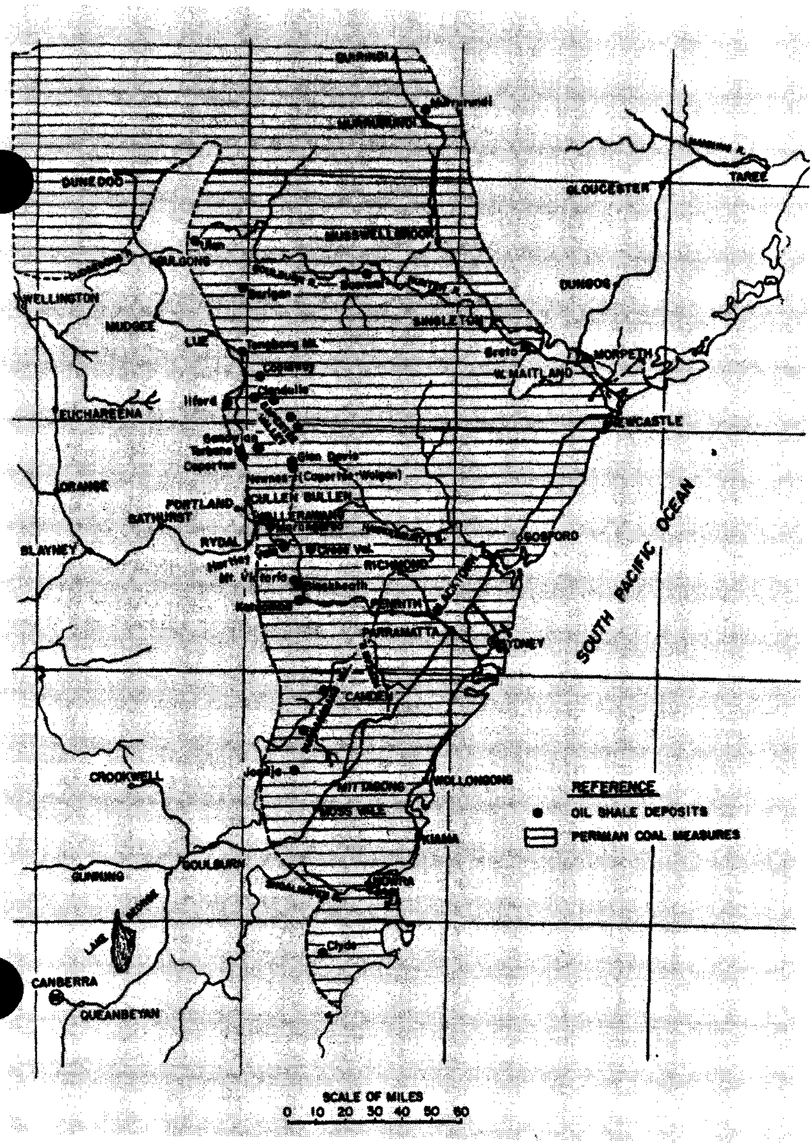
AUSTRALIAN OIL SHALE INDUSTRY PRODUCTION



A robust industry developed mining and selling the richest shale (80 to 200 gallons of oil per ton called "export shale") to the United States and Europe while the "seconds" (less than 80 gallons per ton) were retorted locally for production of liquid fuels and related products. The New South Wales industry survived two severe setbacks -- the Panic of 1893 in which the state bank failed and the establishment of Commonwealth Government in 1902 which immediately repealed the state tariffs(2). The recovering industry could not survive a third devastating upset, the invention of the incandescent mantle. In 1911, this simple invention made it possible to burn any gas with a brightness exceeding the richest gas from torbanite and abruptly ended the export market for raw New South Wales oil shale. There followed a letdown period in which the industry struggled to continue as the richest resources were exhausted, labor problems became overwhelming, and pressure mounted from ever cheaper imports of American and nearby Borneo crude oil. Production finally ceased in 1925. Several private attempts to restart the industry were unsuccessful. Under mounting pressure from labor, the state and commonwealth governments stepped in and the Newnes and Tasmania Investigating Committees were commissioned in the early Thirties to see what could be done to revive the oil shale industry. These were powerful, well lead committees chartered to amalgamate oil shale interests and negotiate with labor. Nothing came of the Tasmanian effort but the Newnes Committee established the framework for rapid startup of New South Wales production at Glen Davis in 1939 for important emergency production in World War II. The final cessation of production in 1952 was as much due to exhaustion of the best resources in the vicinity of the operating plant at Glen Davis as to renewed pressure from imported crude oil. Clearly, if conditions had been more favorable, production could have continued from known resources at Baerami.

The oil shortages and increased prices of the Seventies brought renewed interest in Australian oil shale. Exhaustion of the New South Wales resources, modern mining methods, and the need for economies of scale dictated investigation of the far larger but much leaner tertiary deposits in Queensland. Nine major deposits with total resources exceeding a trillion barrels of oil are under intensive investigation for potential commercial development.

The length of report permitted on this occasion does not allow mention of many interesting and novel aspects of the Australian industry. The references



Oil Shale Locations in New South Wales, Australia

Courtesy of US. Bureau of Mines

listed are recommended for those with indepth interest. Of the numerous references cited, some must be singled out for their critical contribution. The monumental works of J.E. Carne were indispensable for historical fact. Eardley's book(2) and Ferguson's paper(3) were particularly interesting and useful for pictorial documentation and correlation of historical events. Lishmund's work(4) presents details on the current assessment of oil shale resources remaining in New South Wales. The cooperation of Australian Government agencies, TransPacific companies and Murphy Communications, Inc., of New York is acknowledged for the description of current Australian efforts to revive the oil shale industry.

This review concludes that there is the potential for commercial oil shale activity in three of Australia's states, namely New South Wales, Tasmania, and Queensland. Highlights follow, presented by state and project, to substantiate these conclusions.

NEW SOUTH WALES

The colorful oil shale industry of New South Wales was developed under similar physical circumstances to that facing development of the U.S. Green River Formation. The initial discoveries of important deposits of rich torbanite were made on the western outcropping of the permo-carboniferous coal beds about 100 miles from the coast. The area was relatively undeveloped semi-arid grazing land cut by steep sided canyons a thousand or more feet deep. The shale deposits were lenticular in nature, generally outcropping above steep talus slopes at the base of vertical cliffs of sandstone. There were no large rivers for water supply, roads were poor or nonexistent, and railroads did not serve the area when development started in 1865. This review focused on lessons learned that would have application or provide insights into critical aspects of U.S. oil shale development. The historical discussion of individual projects which follows highlights these important areas:

- How was access to deposits achieved?
- How were material handling problems solved?
- How were water supply problems solved?

- Is there evidence of permanent damage to the environment in areas of intense operations?

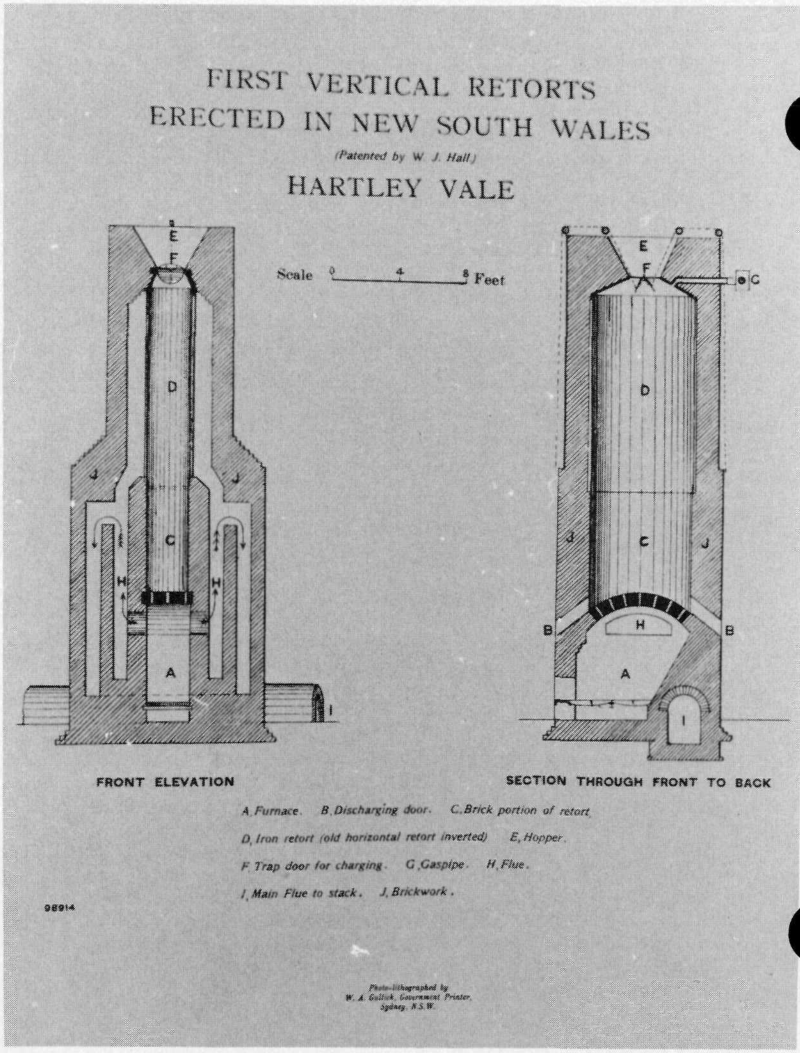
Mount Kembla

The first oil shale operation in New South Wales was that of The Pioneer Kerosene Works established in December 1865 at American Creek on the north slope of Mount Kembla about 5 miles from the coast west of Wollongong. A local land owner had a sample from a 55-inch outcropping of shale tested; it was found to produce 50 gallons of oil per ton. An American oil refiner was hired to design, build, and manage a bank of retorts and distillation units that produced an average of 1500 gallons of illuminating oil per week. A short trail was cleared to the nearest road for access to the site. Skipways were believed to have been constructed to move the shale from adits 32 feet above the plant. Coal was taken from a seam 70 feet above the shale for heat and steam. The retorts were horizontal D-shaped batch ovens in which the shale was placed by hand followed by heating from an external coal furnace. Vapors were collected and condensed in a simple still. The lamp oil product was delivered by horse cart to local store owners. The operation did well and was initially expanded. Unlike other oil shale operations soon to follow, export shale was not produced at the American Creek site.

The initial price for product dropped from 5-shilling 6-pence per gallon to 1-shilling 6-pence as the United States recovered from the Civil War. A 6-pence per gallon import duty on oil was not sufficient for the operation to continue as competition was also felt from the larger more efficient oil shale operation which had started at nearby Hartley. Several changes of ownership and management occurred. Major alterations and expansion were attempted but industrial strife including a series of destructive fires led to sale of the oil plant in 1878 to the Mount Kembla Coal and Oil Company. A seven mile railroad was engineered to connect the site directly to a shipping pier. The oil works were not used again and it is not certain that any raw shale was ever shipped from the site. The shale seams were reported to be near exhaustion(5) and the new management concentrated on coal production.

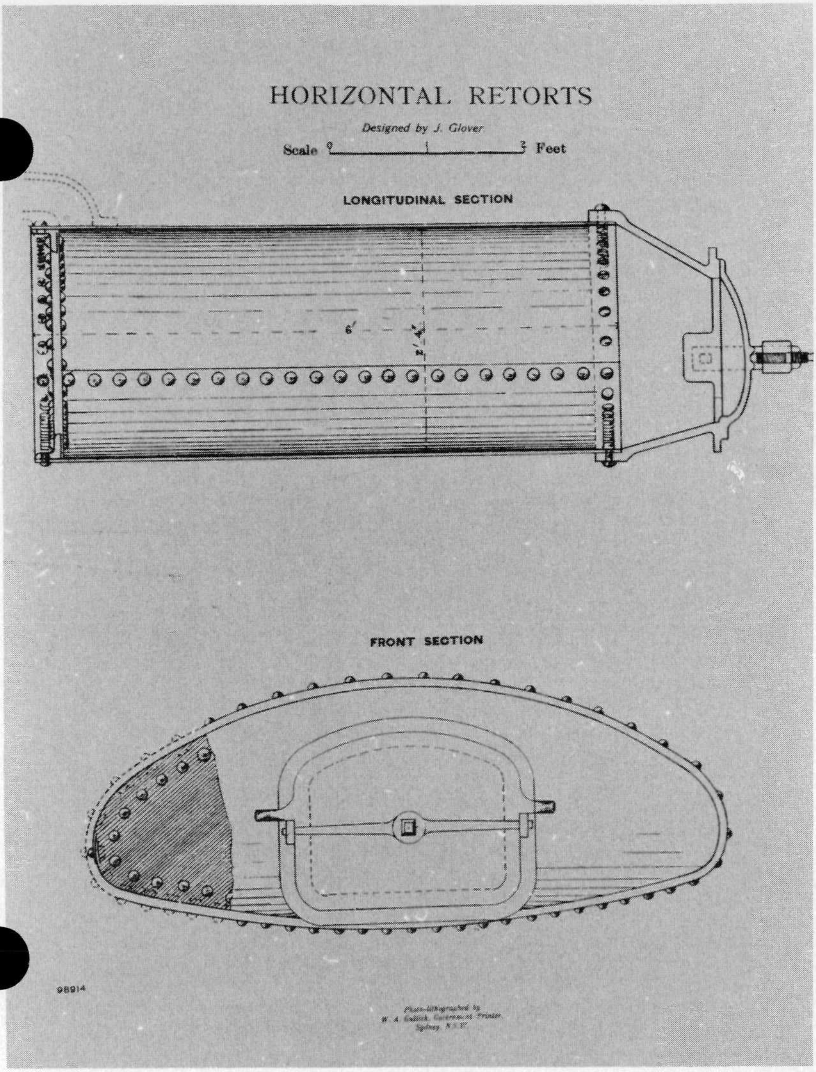
Hartley

Oil shale operations in the Hartley area were the first to occur on the exposed western edge of the Permian coal measures of New South Wales. The Hartley Kerosene and Paraffin Co. was established in July 1865



Early Australian Oil Shale Retorts

Courtesy of NSW Department of Mines and Agriculture

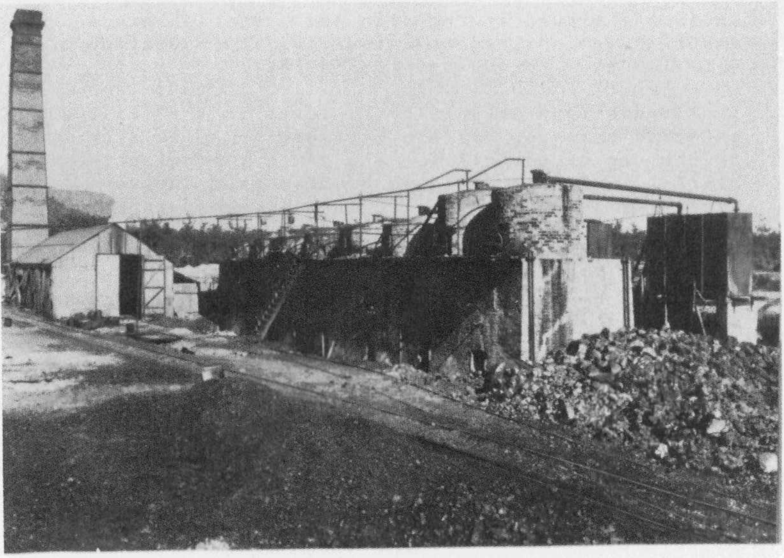


Early Australian Oil Shale Retorts

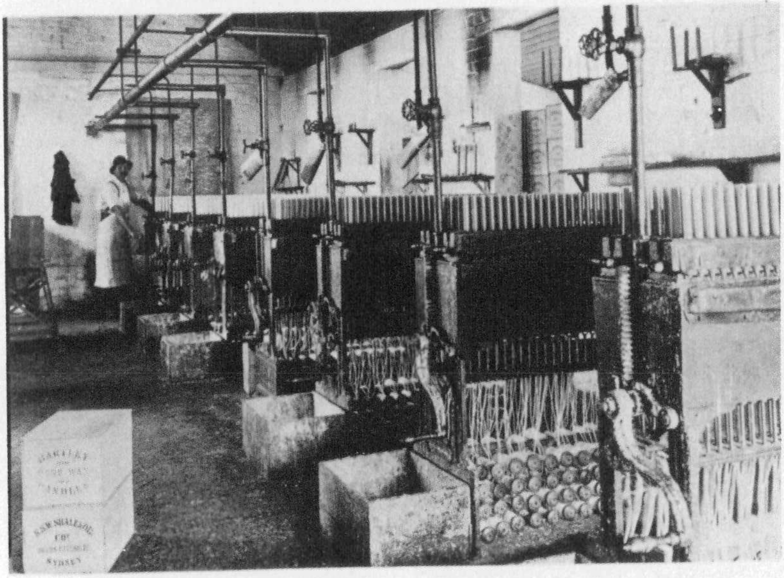
Courtesy of NSW Department of Mines
and Agriculture

and began opening a mine in Mount York above and on the southwest side of the valley of Petrolea Vale. Production of raw shale began in 1866 preceding the extension of the railroad into this remote region 138 miles from Sydney. Initial production consigned to the Sydney and Melbourne gas works was hauled over 50 miles by horse drawn wagons, initially west then south across the valley floor to the Bathurst to Sydney Road then east up to the 3000 foot crest of the mountains at Mount Victoria and down the long grade to the nearest rail head at Penrith, midway to Sydney. From Penrith the shale went by rail to Redfern Terminal in Sydney where it was transferred back to horse drawn vehicles for delivery to the local Australian Gaslight Co. or to the waterfront where Melbourne shale was loaded aboard sailing colliers. This operation in "export shale" provided cash flow to the company while oil production was developed. Limited water supply in the Hartley area initially caused the company to look elsewhere for a refinery site and Penrith was considered. The decision was made to build retorts and a refinery at Petrolea Vale and back loading of general supplies, materials handling equipment, and heavy retort components over the long tortuous route began. By the end of 1866, a quarter mile of Metre gauge tramway was completed from the mine on Mount York to the valley floor. Retort and refinery operatons were tested at pilot scale in an experimental plant in Sydney resulting in immediate production of high quality kerosene when full scale operations did start at Hartley. The product of this simple circular retort(6) was hauled by ox cart to Penrith for rail shipment.

Another Hartley company, the Western Kerosene Co., Ltd., was established in Feburary 1866 and opened a mine midway up the 600-foot slope north of Petrolea Vale. By the time they went into production in 1868, the railroad had been extended to Mount Victoria at the crest of the mountains just south of Petrolea Vale. This company responded to the water supply problem by building their retorts and refinery at Waterloo, 3-1/2 miles from the Sydney railroad yards, taking water and discharging waste into Shea's Creek. Mr. Fell of England was given the job of designing and building the retorts and refinery. By December 1868, the refinery and 15 retorts, each of 500-pound capacity, fashioned after gas retorts had been made in England and erected at Waterloo. Their main product was kerosene marketed as "Comet Oil" the "Bottled Sunshine of Australia" to local markets as well as New Zealand, the United States, India, China, and Europe. Other products included gasoline, benzene, spongaline, paraffine, and lubricating oils.



Retorts at Hartley Vale in 1906
Courtesy of NSW Government Printer



Candle Factory at Hartley Vale in 1906
Courtesy of NSW Government Printer

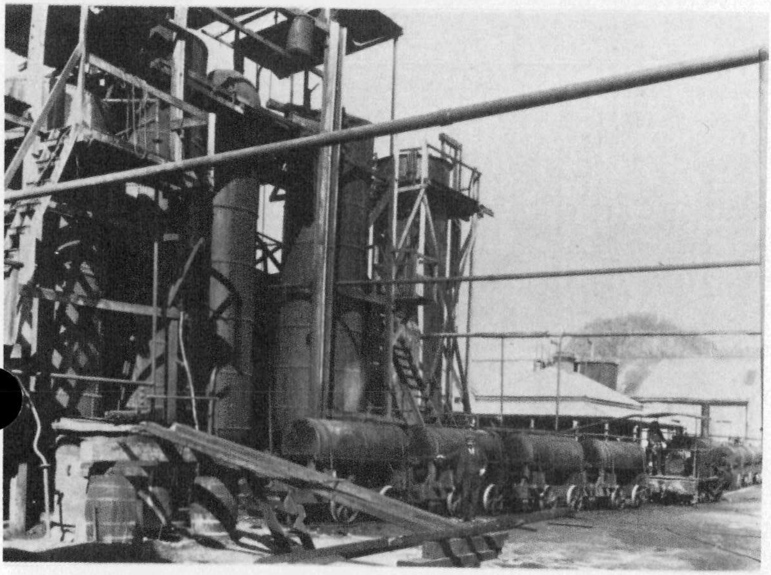
Shale was graded at the mine and only high grade material was shipped to Waterloo. The operation at Waterloo grew to 100 retorts in 1877.

Operations at Hartley improved as the railroad extended past the Western Kerosene Co. mine site but at the top of the cliff. The company constructed its own 2-1/2 mile metre gauge tramway from the new Hartley Vale Station ending in a 650-foot rope haul incline descending at grades up to 1 to 1 into the valley. The rope haul was powered by a steam driven winding engine. Trains were made up at the top of the incline and initially horse drawn to the railroad siding.

In 1873, the Hartley Kerosene and Paraffine Co. and Western Kerosene Co., Ltd., merged to form the New South Wales Shale and Oil Co., Ltd. Their material handling tramways were interconnected at the Hartley mines and a new bench of retorts and a refinery were completed at the Hartley site by 1880 to process lower grade shales. In the early 1880's, small steam locomotives replaced horses for the valley floor and hilltop tramway operations. Five thousand tons of raw shale per month were shipped to Sydney mostly to the retorts at Waterloo and 2000 gallons per week of oil were shipped to Sydney for further treatment. The village of Hartley Vale was built for workers' homes, dams were built on the valley floor to solve the water problem. Shipments of raw shale to Waterloo diminished. By 1886, the company obtained a private siding at Ultimo in Sydney where lubricating oils and greases were manufactured, replacing the operations at Waterloo completely. Most of the components of Waterloo were moved to Hartley Vale during the 1880's. By the end of the 80's it was apparent that oil shale reserves at Hartley Vale were nearing exhaustion. In 1889, a good shale seam was discovered 71 feet below the valley floor under the main plant. The exact nature of the faulting that resulted in this occurrence was never established but mining at Hartley Vale did continue until 1903. Improvements continued to be made at Hartley Vale, in 1893 the rope haul was replaced with an endless system and tunnels were added to drain the mines. In 1896, the company leased shale at Genowlan and in 1905, 30 or 40 tons per day of second grade shale from the Narrow Neck area were hauled in and mixed with local seconds to keep the operation going. In 1906, the Commonwealth Oil Corporation of Torbane purchased the Hartley works. The new company concentrated on its operations at Torbane and hauled Torbane oil to Hartley for re-fining. In January 1909, a tank wagon of naptha exploded due to a fire on the oil soaked railroad

Hartley Vale Incline in 1906

Courtesy NSW Government Printer



Hartley Vale Refinery in 1906

Courtesy NSW Government Printer

tracks. Commonwealth did some mining at Hartley Vale until 1909 when the Fell family took over. The site was closed in 1913 and components were moved to Newnes during the period 1915 to 1918. Test bores were sunk to look for more shale in 1921, but the site remained closed. Observations 30 years later noted that vegetation had not yet taken over the heavily oil soaked rights-of-way. It was also noted that some of the spent shale had been removed for use in cosmetics and as an abrasive in tooth paste. Working conditions at Hartley Vale were described as inhuman but there was always someone to replace any dropouts(7).

Joadja

The initial oil shale export operations from the Joadja area were a most difficult materials handling problem involving a very tortuous 18-mile haul to the railroad at Mittagong. First, the shale had to be hauled by horse down the 500 feet from the mine in the canyon wall to the valley floor below, then across Joadja Creek to the base of the southeast canyon wall. Here the shale was shifted to one ton ox carts where the teams of 14 oxen each pulled the one ton loads up a steep zig-zag road to the top of the canyon wall. The shale was again shifted into 6-ton horse drawn wagons for delivery to Mittagong, about 200 tons of shale per month being delivered by this method. When a rival company formed and closed this route a double track tramway was constructed first to the valley floor and then to the top of the canyon wall. Lowering operated on a self acting gravity principle and mules were used to move shale a mile on the valley floor. The up incline was a rope haul using two horses harnessed to a vertical winding drum. In 1877, the rival company completed a more substantial incline using a 40 hp steam winding engine to lift the shale skips up a track 3000 feet long involving slopes as steep as 1 in 2. The rival interests in the Joadja area consolidated forming the Australian Kerosene Oil and Mineral Co. in 1878, and erected 31 horizontal coal fired retorts to retort "seconds" on the valley floor. Shale oil was also refined. Gasoline produced was considered to be a waste product and was dumped in the stream. By 1880, a private railway was completed to Mittagong and 5 narrow gauge locomotives were moving 350 tons per week to Mittagong in 1881.

In that same year, Scottish miners were imported and for the first time a coal cutting machine was used to undercut the shale(8). Retorts were expanded to 66 in number of 5000 pounds capacity each(9).

The blue oil and paraffin products were sent to Sandown near Paramatta where the company operated candle and lubricant factories. Other products included:

- Kerosene - sold for lamp oil
- Naptha - used in Naptha lamps and portable gas lamps
- Gasoline - some sold for gas machines
- Cleaning oils including Benzene, Spongaline, and engine-cleaning oil
- Preserving oils
- Lubricants including axle oil, cylinder oil, machine oils, skip grease, axle grease, standard grease, transparent grease, and hot neck or wool grease.

A comfortable self sufficient village with its own orchards, gardens, and farms for fresh food developed. A high spirited colorful crew enhanced efficiency. It was said later strikes resulted from instigators planted by outside interests(10).

The Joadja operation never really recovered from the Panic of 1893, labor troubles grew into strikes, the company sought richer shale at other locations, and Joadja operations ceased with the cancellation of tariffs in 1902. Major prospecting efforts were carried out in 1906 and 1922 but production was never restarted at Joadja. Some of the living areas were destroyed by bush fires and never rebuilt but the orchards and farms continued to serve the area and began exporting food.

Narrow Neck

The most colorful oil shale operations in New South Wales developed around the southern extension of the high table land at Katoomba. This narrow vertical sided ridge stood 600 feet above its talus slopes leading to the Jamison Valley on its east and Megalong Valley to its west. With the railroad at Katoomba a mile north of the cliff face and the shale seams in the talus slopes 300 to 400 feet below the 600 foot vertical drop the materials handling problem was formidable. A coal mine had opened at the 600 foot level in 1879 and was connected to the railroad by a 24-inch narrow gauge skipway ending in a 1300 foot steam driven cable haulage incline to descend the 600 feet. In 1886, the Katoomba Coal and Shale Company, Ltd., opened the Ruined Castle Shale Mine about 2 miles across the Jamison Valley south of the foot of the incline. Only export shale was to be moved to the railroad, this to be accomplished by an aerial bucket tramway about 2 miles long with one terminal at the area called "Engine Bank" at the top of the coal mine incline and the other at the rock formation called Ruined Castle stretching 1000 feet above the valley floor. There may have been some supporting towers on hills in the valley. In any case, the aerial tramway had a short life having moved only about 500 tons of shale when some accident caused the southern terminal to be pulled from its foundation into the valley below. The company could not afford to repair the damage and ceased mining shale.

In 1890, the Australian Kerosene and Mineral Company faced with exhaustion of resources at Joadja acquired first the Glen Shale Mine area on the west of Narrow Neck and then the Ruined Castle Mine. The Joadja company doubled the main incline to two tracks and extended the cable haulage via trestle over the edge of Jamison Valley and tunnel through Narrow Neck to the Glen Shale Mine on the west. A horse tramway to the Ruined Castle Mine was carved out on the talus slopes east of Narrow Neck. By these routes the two shale mines were worked until 1903 for export shale with seconds being left at the mine entrances. These seconds and trimmings piles at Ruined Castle were burned in bush fires with the shale remaining hot and giving off steam for many years. An attempt was made to retrieve 16,000 tons of seconds at the Glen Shale Mine and much of the equipment before the Joadja company's lease expired in 1906.

Genowlan

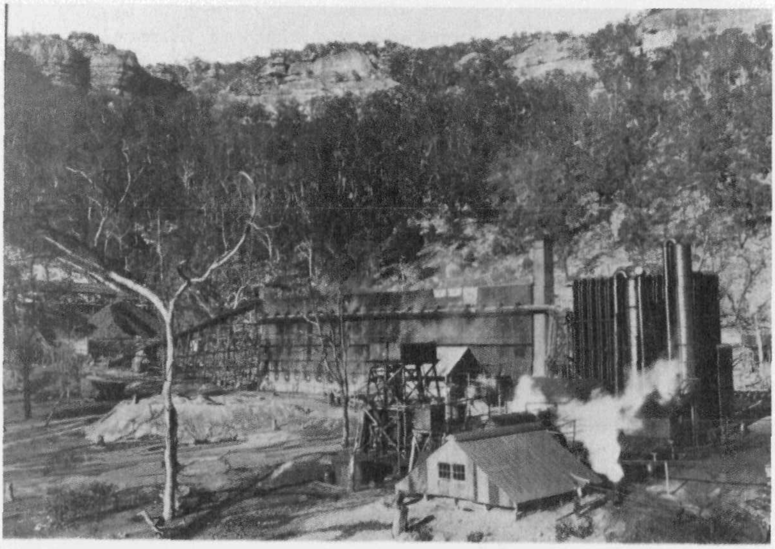
The Genowlan shale operation was unique in being the only German shale venture in New South Wales of the time. Situated just north of the Newnes area on Airly Mountain it served to open the area to settlement when the railroad reached Capertee in 1882. The shale seam on the east side of Mount Airly away from the Capertee Valley was discovered in 1883. The German syndicate Genowlan Shale Company took over the southernmost leases that same year and began to send export shale to Germany. The shale was hauled by horse or ox teams seven rugged miles from the mine to the end of the railroad at Capertee Station. The Germans quickly installed a narrow gauge tramway to bring shale down the mountain with self-acting inclines at the steepest parts and horsepower moving the 1500 pound loads in other areas. The leases passed to the Australian Kerosene Oil and Mineral Company operating at Joadja in 1897. As the state railroad had now extended north to Mudgee the new firm quickly arranged for a siding at the point closest to the base of the German tramway. The siding was called Torbane after the Scottish town that had given the name to Torbanite. Horse operations continued until 1903 when the tramway equipment became available from Narrow Neck. A costly and time consuming double track skip haulage was then constructed from the base of the German built incline to Torbane siding. The system received little service as the Joadja company was failing and was taken over by Commonwealth Oil Corporation in 1908 which itself failed in 1912. Some shale was shipped during this period to Newnes and the Railway Gas Works at Sydney(11).

Torbane

The northern leases on Airly Mountain were worked to a very limited extent starting in 1883. No significant activity occured until the leases were taken over by The New South Wales Shale and Oil Company of Hartley Vale to replace their expiring resources at Hartley Vale. Unlike the southern operation, the Hartley Vale company constructed retorts at the base of the mountain to retort the "seconds." These were continuous vertical retorts of Scottish design. Oil somewhat heavier than Hartley Vale oil started being produced in 1900 and was shipped 43 miles by rail tank wagons to Hartley Vale for refining. A standard gage private railroad covered the two miles from the Torbane plant to the state railroad. A narrow gage tramway was constructed from the plant up and over the north side of Mount Airly to the northern leases, now called the New Hartley Mine. The cable haulage ended in a horse drawn tramway that served the numerous adits of the mine. Commonwealth Oil Corporation also took over the operation and added a half bench of Bryson retorts but production diminished after 1909 and ended with Commonwealth's demise in 1912. Some prospecting did occur again in World War II(12).

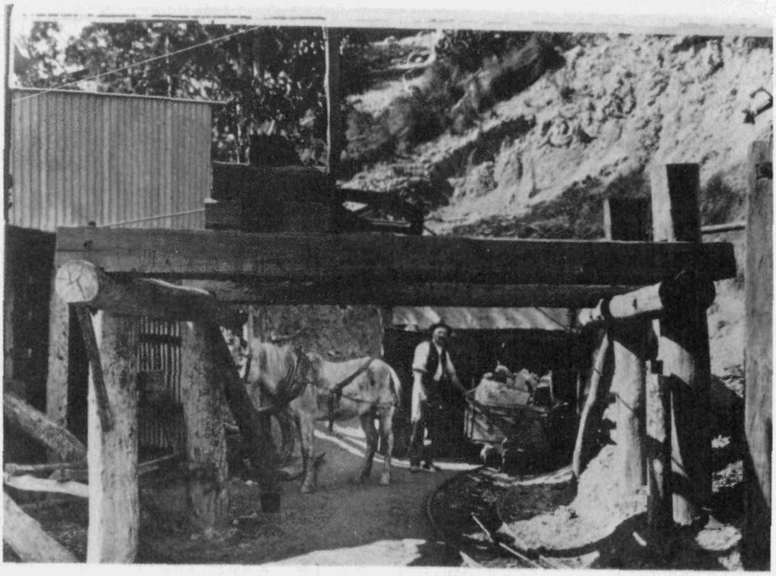
Murrurundi

The oil shale seam at Temi, 4 miles north of Murrurundi, is of unique geologic origin. It is in reality a brown cannel coal producing about 60 gallons of oil per ton but its early popularity for producing gas suggests that it also had gas properties comparable to the best torbanite. Development was started for one year in 1883 by the Northern Shale Company. The manager returned to work the shale



Retorts and Condensers at Torbane in 1906

Courtesy NSW Government Printer



Torbane Cable Haulage Anchor at a Mine Adit in 1906

Courtesy NSW Government Printer

privately for 6 months in 1887 and sold 650 tons to various Australian gas companies. His comments(13) provide some important insights into the relative costs of material handling at the time. The cost of mining and moving to tunnel mouth was 15 shillings per ton, cost of hauling by ox cart to the railroad (about seven miles) was 13 to 15 shillings per ton, and the cost of freight for about 120 miles to Newcastle was 9 shillings, 8 pence per ton. Bad roads and primitive modes of haulage were cited by him as major problems. He could not afford a retort or a link to the railroad.

The project was inactive until 1905 when the syndicate which had been operating the Genowlan Shale Mine put in an aerial ropeway from the Temi mine to Temple Court about 3/4 of a mile from the railroad at Murrurundi. A private railroad was laid to connect with the Great Northern Railway. The operation at Temi and Temple Court was incorporated in 1910 as the British Australian Oil Co., Ltd., but German ownership apparently persisted and would cause problems in the upcoming war. The new company built a bench of Scottish retorts at Temple Court and refinery at Hamilton near Newcastle. In two years (1909 to 1911) the company reported 11,800 tons of production but the operation was sporadic. The aerial system apparently gave many problems. There were reports that the refinery operated to the end of the war when it was seized as a war prize, closed down, and sold as scrap. In demolishing the refinery the stock in tanks was emptied into Throsby Creek to run to sea, hot coals from a passing train lighted the creek and oil at sea afire(14). The oil works at Temple Court were also demolished in 1918.

Marangaroo

The shale deposit at Marangaroo received early attention by the Machenzie brothers(15), pioneers in the Australian shale business. They erected a retort at their home in Kerosene Vale similar to the first erected at Hartley Vale. They produced some oil but concentrated on improving the properties of the kerosene. The deposit, however, is most known for emergency World War II production(16). Lithgow Oil Pty. Ltd., erected three NTU retorts at the south end of the deposit based on information from the U.S. Bureau of Mines operation at Rulison, Colorado. This was perhaps the best known and most successful of the "backyard" stills that sprang up during the war. As a primitive plant built with available used materials, it was rather sophisticated incorporating recycle gas and instrumentation to correct early difficulties.

The basic retort was a 10 foot steel cylinder 24 feet high, lined with fire bricks. Each was filled with shale in a batch operation, the shale was covered with bundles of sticks, a little oil was added to expedite the spread of the fire and the contents were lit. When the fire was burning well, the lid was closed and exhausters pulled the fire down through the shale. By this method on 33 hour cycles, 4 million gallons of oil were produced during the war years.

Newnes

The Newnes-Glen Davis oil shale deposit was discovered about 1865 under the 2000 foot high ridge between the Capertee and Volgan rivers where they cut through the western edge of the Sydney Basin. The names Newnes and Glen Davis were unknown when the first small production started in the area in 1871. The first production was brought out of the Capertee side by team and wagon to the railroad at Capertee and even an animal pack train was tried for bringing shale out of the Volgan river valley before the road was constructed in 1879. The first significant production in 1894 came primarily from the Capertee side (Glen Alice area) and was hauled by team to the railroad.

The remoteness of the area and an unusual chain of events would give the area the most checkered history of any Australian oil shale operations even though it would become the hub of oil shale activity for the transition from export shale operations to liquid fuel production and the critical large scale production of alternate fuel for World War II. Production in the 1894 to 1896 period proved up a sizable deposit but also proved that export by road was not profitable even for the highest grade export shale. A tramway to the Capertee side was proposed and the state parliament by the Capertee Tramway Act of 1896 authorized the investigation of three alternate routes(17). The engineering for the tramway proved to be a formidable task and nothing was done until Commonwealth Oil Corporation came on the scene in 1906. Their first decision was to build their works on the Volgan side instead of the Capertee side by reasons of better water supply and most importantly better access for construction of a railroad. There followed the construction of 32 miles of private railroad over very difficult country through 2 tunnels and around precipitous cliffs in just 13 months at a cost of 130,000 Pounds, a remarkable achievement made all the more interesting by the fact that it was constructed directly under the engineers supervision to save the time that would have been required to complete drawings(18). The works in the Volgan valley were named Newnes after the Chairman of the Board for Commonwealth and the junction with the state railroad 88 miles from Sydney became known as Newnes Junction.

The corporation's cash flow problems were greatly aided by discovery of a seam of coal particularly suited to production of metallurgical grade coke. A coke works was quickly erected and the primary traffic for the new railroad was coke enroute to the Cobar smelters and back-hauling materials and equipment for the oil works. For the transport of coke and export shale nineteen 32 ton high-sided rail cars were constructed. As the shale mine developed these cars regularly made the trip to Darling Harbor with the export shale. When their lease-hold was approved in 1906, Commonwealth immediately began driving tunnels into the shale seam from both the Capertee and Volgan sides intending the tunnels should meet, providing access to the entire deposit of 20 million tons proven and 30 million tons of presumed reserves. About 2500 feet in, however, the Capertee tunnel was abandoned as the shale seam gradually thinned to 8 inches from the 2 feet at the outcrop.

Luck was running out for Commonwealth, even though construction of the oil works went extremely well based on utilization of an on-site brick works, railroad cranes for construction, and their wealth of experience with the Scotch Pumpherston retorts, a bench of 32 being erected. When operations started, it was found that the Pumpherston retorts were not suitable for the rich shale at Newnes. The main problem was the large amount of gas produced which would start burning inside the equipment. The company struggled, surviving on profits from the coke and export shale operations and concluding operations at Hartley Vale and Torbane which had been purchased. In spite of the equipment problems, a six-month labor dispute in 1909, and cut-throat competition from oil importers, the first oil was refined in August 1911. Production concentrated on kerosene and the same by-products as mentioned for other shale plants, but now ammonia was becoming an important by-product. Gasoline was still a waste product dumped in the Volgan River. The export trade ended, and in December 1911 the company attempted to sell the railroad to the state to gain capital but the state refused it and Commonwealth went into liquidation. The works closed in 1913.

David Fell was appointed receiver to conclude activities of the Corporation. He immediately obtained a revision of labor regulations to improve productivity, sold excess equipment, and consolidated operations from Hartley Vale, Torbane, and Glen Alice at Newnes. He brought his brother John from England to redesign the retorts, and aided by the urgency of war production, restarted in 1914. In April 1915 a reorganization was approved under the name John Fell and Company, Ltd. In 1919, the company was again reorganized with John Fell appointed manager. This touched off serious labor troubles and the oil works closed in February 1920. In 1921, Mr. Fell tried some experiments in insitu retorting(19). They were deemed successful on a small scale, but the state Mines Department prohibited large scale experiments for fear that fires could not be controlled. Fell struggled on with an offer to the employees at Newnes to form a cooperative, but all production ended in 1923. Gasoline became important. There was an attempt to refine gasoline from shale oil with a UOP (Universal Oil Products of the United States) Dubbs cracking plant erected at Duck Creek near Clyde but the operation came to a calamitous end with an explosion on August 22, 1927 killing three men including John Fell's son, ending the Fell family dynasty in Australian oil operations. Shell took over the Duck Creek refinery in 1928. With the Volgan railroad having terminated operations in 1926 many of the employees could not even take their personal property with them to seek employment elsewhere. Mr. A. E. Broue took over the leases at Newnes in 1930 and attempted to start operations with support from mining interests but failed for lack of capital.

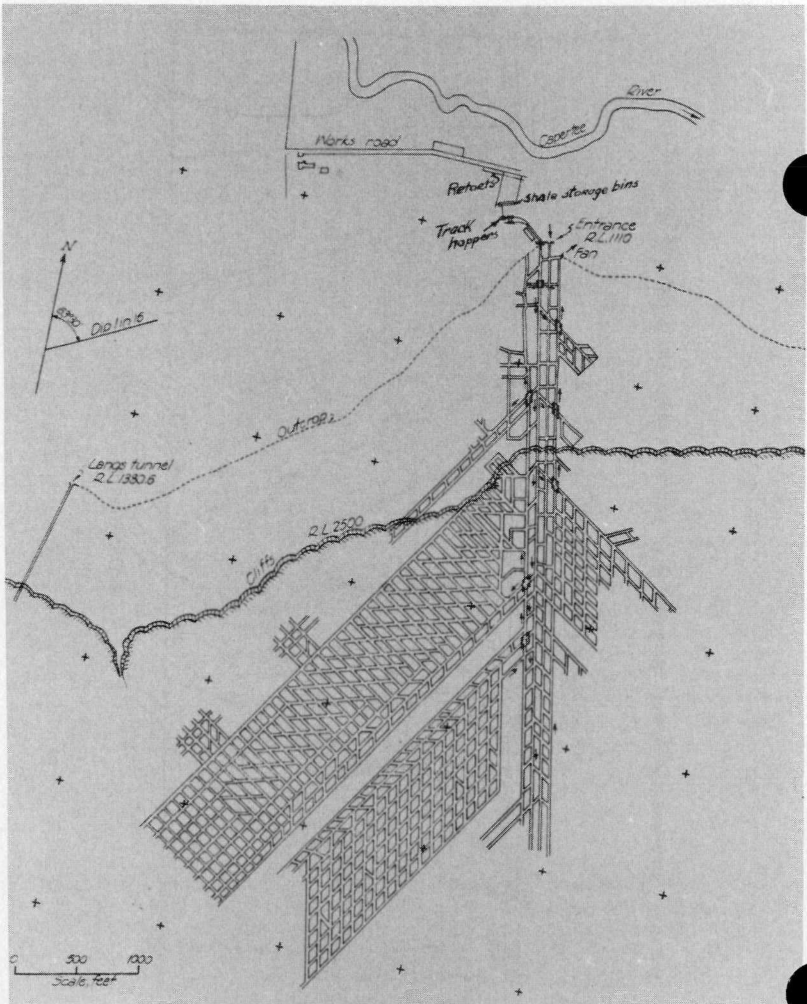
In 1931, limited production was achieved by the Shale Oil Development Committee, Ltd. under a grant for relief of miners, but apparently ended with spending of the grant. Other attempts involving foreign companies were unsuccessful. The Newnes Investigating Committee was commissioned in 1933 by agreement between the State and Commonwealth Governments with the Shale Oil Development Committee, Ltd. to investigate the possibility of developing the shale oil industry in the Newnes-Capertee area on a sound basis. After a most exhaustive investigation including detail planning, a detailed report(20) concluded that further reduction in gasoline prices precluded forming a company within the terms of reference given the Committee. Approaches to Imperial Chemical Industries were declined and in May 1936, the Commonwealth Government announced it would nationalize Newnes and asked for proposals to operate it. The agreement reached with Mr. George Davis in 1937 led to transfer of the Newnes plant to the Capertee side and construction of the Glen Davis project.

Glen Davis

When Mr. George Davis made his agreement with the State and Commonwealth Governments to operate the oil industry at Newnes he received 500,000 Pounds from these governments and formed the National Oil Company with 600,000 Pounds capital. As such, the venture was not a true private enterprise venture. The new company's first decision was to move the operation 70 miles by road to the Capertee side of the ridge in the Glen Alice Valley, now renamed Glen Davis. The details(21) of this undertaking are beyond the scope of this report, but a few observations are appropriate to place it in context with other projects described. The water problem was solved by running a pipeline 50 miles to the Fish River near Oberon. For the first time a pipeline was used for product delivery, as the railroad was not extended to Glen Davis. The pipeline was run 30 miles over the ridge and along the abandoned Volgan railroad right-of-way to Newnes Junction.

After careful testing of samples by UOP, a new refinery was purchased from the United States, including a UOP Dubbs cracking unit to maximize gasoline production. A planned town was built early on to improve living conditions. A highly mechanized mine using electric power was developed by the room and pillar method. Even so, productivity at 3 tons per man shift was only a modest improvement over the ton-per-man shift of hand methods employed in early ventures. A preference for long wall mining was frequently discussed. The Fell retorts were re-erected and eventually performed well. It was observed that the loss of efficiency by not retorting fines was not great as fines were usually the leaner material that was more friable.

The greatest problem was the inability to produce enough shale to feed the plant. Renco and NTU retorts were tested but never put to use at Glen Davis. The U.S. Oil Shale Mission visited Australia in 1942 and recommended expanded operations but the war ended without any major changes. The end of the war brought back competition from imported crude, the resource was nearing exhaustion, and a flood did major damage to the plant in 1949. In the absence of a clear policy on government support, the operation drifted to final closure in 1952.



Extent of Glen Davis Shale Mine in
September 1947

Courtesy of U.S. Bureau of Mines

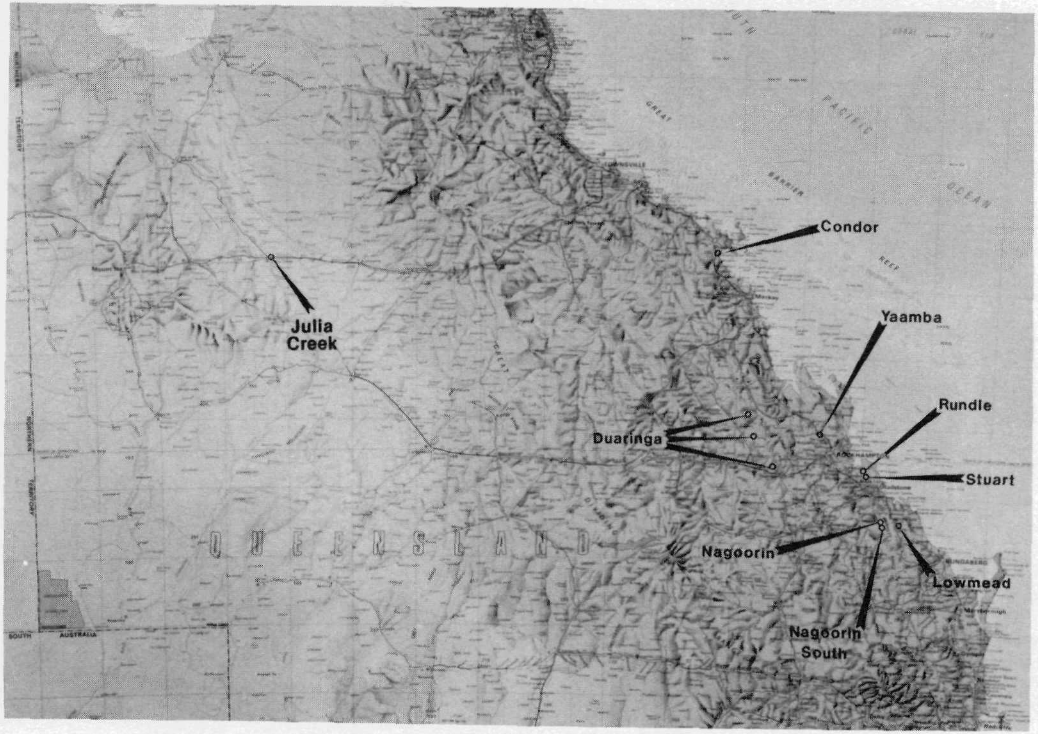
TASMANIA

Oil shale activity in Tasmania never really achieved stable commercial operations. During the period from 1910 to 1932, eight of the most significant operations did produce a total of nearly one quarter million gallons of oil(22). Activity centered on the Tasmanite deposit in the Latrobe-Railton area on the north central coast of the island state. Tasmanite is a leaner shale but of a more continuous nature than the Torbanite deposits in New South Wales. In the two mines developed near Latrobe, the working seam varied from 5 to 6 feet in depth with a top band about 2 feet thick, yielding about 40 gallons per ton, a middle band about one foot thick yielding 8 gallons per ton, and a bottom band 2 to 3 feet thick yielding 30 gallons per ton. Overall yield was about 33 gallons per ton. The seam is known to extend over many square miles; possible resources over 30 million tons have been estimated. The oil produced was heavier and had a higher sulfur content (2%) than oil produced from Torbanite. Yields of over 60% kerosene and diesel oil were reported from relatively simple refining techniques. The experimental and developmental activities of several companies since the 1890s have shown the Tasmanite can be mined relatively easily. Experiments with several retorts including the Hall, Schultz, MacPherson, Crozier, Bronder, and Pumpherston suggests that Tasmanite could be effectively retorted in retorts of current design. Important anomalies may be the close relationship between oil yield and specific gravity of the shale and the friability of the lean middle band, which suggests relatively simple beneficiation.

It was also noted that the spent shale was utilized by the local potato farmers and orchards as a soil conditioner. Work by the Tasmania Cement Company and its successor, the Goliath Portland Cement Company, suggests the possibility of integrated production of cement and oil, or at least utilization of the Tasmanite in cement production(23).

QUEENSLAND

The first oil shale discoveries(24) in Queensland resulted from sea erosion of the Tertiary lake deposits along the east coast. The first in situ discovery resulted from coal exploration in the Duaringa Basin in 1891. Only the discovery near



Oil Shale Locations in Queensland, 1983

Adapted from Southern Pacific Petroleum N.L.
Annual Report for 1981

Warwick southwest of Brisbane appears not to be related to major deposits currently under investigation. Nine of the most active investigations are discussed in the following paragraphs.

Julia Creek

The Toolebuc formation extends south of the Gulf of Carpentaria through central Queensland, covering 250,000 square kilometers. At varying depths in the formation there is a consistent 7-meter layer of oil shale averaging 60 liters per ton. Near Julia Creek, the St. Elmo structure has broadly lifted the Toolebuc Formation to near the surface providing a wide area suitable for surface mining of the oil shale. From the mid-1960s to 1979, Aquitaine Petroleum Pty., Ltd., The Oil Shale Corporation (TOSCO), and Australian financial interests investigated the feasibility of commercial operations near Julia Creek, producing oil and vanadium(25). After 1979, CSR Limited was the focal point of interest in Julia Creek, holding the important Authorities to Prospect near the St. Elmo structure. CSR, Ltd. received two National Energy Development and Demonstration Council grants to investigate optimum retorting temperatures and refining schemes. Large samples of oil were prepared in the CSR laboratory in Roseville, NSW, and sent to UOP in the United States for testing and analysis. The final report(26) dated June 1981 concludes Singapore prices adjusted for Australian parity are not high enough to make an economic profit by the frame of reference scheme. CSR is continuing research.

Duaringa Basin

The Duaringa Basin lies 100 kilometers from the coast due west of Rockhampton. The Basin stretches northwest of Duaringa 100 kilometers and spreads to 20 kilometers wide over the depression west of the Connors Range. Carne reported in 1903(24) that the commercial significance of the 1891 discovery of shale in the Duaringa Basin was being investigated however no activity is known to have occurred. When the Transpacific companies, Southern Pacific Petroleum NL and Central Pacific Minerals NL, began taking interests in Queensland shale lands in 1973 they acquired Authorities to Prospect covering the Duaringa Basin. Their exploration program started in 1978 has developed much of the detailed information known about shale in the basin. A lower seam of richer shale 14 meters thick is separated from an 8-meter thick upper seam, resources of 3.7 billion barrels of shale oil in place were made. Comparison to feasibility studies completed on more advanced projects suggests the Duaringa Basin is sub-economic using known extraction technologies and selling in current world markets. The depth of overburden suggests that in situ, extraction will be needed(27).

Condor

Condor is northernmost of the tertiary lake oil shale prospects on the east coast of Queensland. The Transpacific companies began field investigation of the deposit near Proserpine in 1978 and defined a resource base of 8 billion barrels of shale oil in place. Joint venture discussion led to signing an agreement for a feasibility study with Japanese interests represented by the Japanese National Oil Corporation in December 1981. A new Japanese corporation--the Japanese Australia Oil Shale Corporation--was formed to carry out the feasibility study and work is underway with a slot cut completed to produce 6000 tons of oil shale for materials handling and process testing. Mining, water management, and environmental studies are underway and bench scale retort testing has been commissioned with Lurgi, Dravo, Superior, and Paraho. Funding of US$24 million is to be provided by the Japanese interests. The Japanese Oil Shale Engineering Corporation has a $60 million budget and will provide strong support in studying retorting of the Condor shale. The strong Japanese interest in alternate sources of energy has not been abated by the current world oil situation, suggesting continued strong support for this project. The Condor deposit is still held as a 50/50 partnership of the Transpacific companies(27).

Yaamba

The Yaamba deposit lies just north of Rockhampton, a resource of 1.6 billion barrels of shale oil in place has been defined. If this deposit is found to be contiguous with the nearby deposit at Byfield and discoveries reported by Carne near Port Clinton resource estimates may increase dramatically. Peabody Australia Pty., Ltd. is operator and 50% owner of the important Authorities to Prospect. Central Oil Shale Pty., Ltd. and Beloba Pty., Ltd. (the Transpacific companies) hold 40% and 10% of the project. A feasibility study led by Peabody is underway to evaluate methods of exploitation(27).

Rundle

In 1915, Ball, an Assistant Government Geologist, reported(28) that it was commmon knowledge for years that ships operating in the channel between the mainland and Curtis Island north of Gladstone, dredged up combustible shale. Shale taken from a shaft on a Munduran Company Coal Mining Lease assayed at 28 gallons per ton. There was a spurge of interest in 1911 centered on the thought that petroleum might be found in the area. Activity abated until 1973 when the Transpacific companies took up the important Authorities to Prospect. The northern portion of the deposit near the Narrows was called the Rundle Project. Exploration started in 1974 to develop data for joint venture discussions. These led to Esso Exploration and Production Australia, Inc. taking a 50% interest in the project, and proceeding with a feasibility study of a demonstration plant for the project. In May 1981, Esso decided against a major demonstration plant but work on solving technical and economic problems would proceed. A three-year program to decide if the venture should proceed directly to a commercial plant was defined. The revised program was started with a slot cut raising 17,000 tonnes of oil shale. Thirty-two hundred tonnes were shipped around the world for testing, including 2,000 tonnes to Cleveland, Ohio for testing in the Dravo circular grate pilot plant, and 1000 tonnes to Tosco for testing in their pilot plant at Boulder, Colorado. Earlier testing had been completed in a Lurgi pilot plant. These tests have been completed and work goes on to optimize the system by which the shale could be exploited(27).

Stuart

The Transpacific companies have retained full control of the southern Authorities to Prospect in the Narrows deposit. This portion designated the Stuart Deposit has been calculated to contain 2.5 billion barrels of shale oil in place. Basic properties of the shale are being determined in ongoing tests. The Julius Kruttschmitt Mineral Research Center at the University of Queensland has been commissioned to undertake beneficiation research on a bulk sample taken by 6 inch diameter core boring(27).

Nagoorin

Greenvale Mining NL and Esperance Minerals NL took up the northern Nagoorin Authority to Prospect. The Transpacific companies have earned a 25% interest each in the project by acting as exploration operators. The initial drilling program identified resources of 2.6 billion barrels of shale oil in place. Characterization and beneficiation studies are underway utilizing bulk samples taken by large diameter core boring(27).

Nagoorin South

The southern Nagoorin Authority to Prospect was taken by Mining Houses of Australia, Ltd. Exploration is being conducted by the Transpacific companies to earn each a 26% interest in the prospect. Drilling to define the limits and grade of resource is underway(27).

Lowmead

Oil shale was the subject of extensive prospecting around Lowmead in the early 1900s. Ball reported(29) in 1915 that rich Tasmanite-like material assaying up to 82 gallons per ton was found below the weathered zone in some shafts in the Baffle Creek area. The current Authority to Prospect was taken by Greenvale Mining NL and Esperance Minerals NL. Exploration is being carried out under a joint venture agreement with the Transpacific companies, under which each will earn a 25% interest in the prospect. Southern Pacific Petroleum NL is operator of the joint venture(27).

CONCLUSIONS

The potential for further commercial oil shale development remains high in Australia, notwithstanding the current world oil situation. Public issues such as national security, energy self-sufficiency, natural resource management, and management of the environment will influence the outcome, but some inherent advantages are apparent for Australia.

In New South Wales it seems likely more of the rich resources will be found, most likely in the deeper portions of the Permian coal measures. The lenticular deposits are suited to working by smaller projects more consistent with the current investment strategy of many companies. In Tasmania, the prospects for cogeneration or integrated projects coproducing electricity, liquids, industrial gas, and cement appear most suitable. In Queensland, the prospects for cheaper open pit operations are good. The prospects for finding more resources with new geologic techniques is particularly high. In all three states, the proximity of resources to infrastructure and favorable climate are advantages. The favorable characteristics of oil shale discovered so far and the inherited resourcefulness of the people seem to assure that development will occur when truly needed.

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DEVELOPMENT OF EASTERN OIL SHALE IN KENTUCKY

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INTRODUCTION

Since the interest in oil shale development in Kentucky was renewed by the Buffalo Trace Study in 1980, there has been significant progress toward the rebirth of an oil shale industry in Kentucky. That progress includes the completion of an extensive coring program which will give Kentucky a comprehensive data base on the distribution and characteristics of its oil shale resource, advances in fluidized bed retorting which offers a potential for significantly increasing oil yields, and the development of two commercial projects which are now pending before the Synthetic Fuels Corporation (SFC). This paper will review the progress and direction of the research and development programs since the completion of the Buffalo Trace Study which was reported at the Eighth Energy Technology Conference in 1981 (1) and will focus on the two proposed commercial projects.

The 1982 Kentucky General Assembly, at the request of the Energy Cabinet, broadened the Energy Development and Demonstration Trust Fund to include tar sands and oil shale. Prior to that the Trust Fund had been limited to supporting synthetic fuels activities based on coal. Since 1974 over ten coal projects have been supported by the State at a total cost of over $20 million. The

TABLE 1

KENTUCKY'S FOSSIL ENERGY RESOURCES

	RESOURCE (BILLION TONS)	OIL EQUIV. (BBLS)
COAL	68	170 BILLION
OIL SHALE	60 - 80	15 - 30 BILLION
TAR SANDS	--	2 - 4 BILLION

TABLE 2

(FROM REF. 11)

COMPARISON OF EASTERN AND WESTERN OIL SHALES

	DEVONIAN	COLORADO
% Carbon (organic)	11.70	10.66
% Carbon (inorganic as CO_2)	0.08	21.76
% Hydrogen	1.24	1.50
% Nitrogen	0.40	0.27
% Sulfur	3.03	0.70
Heating Value (Btu/lb.)	2110	2140
Fischer Assay (gal/ton)	12.3	25.2

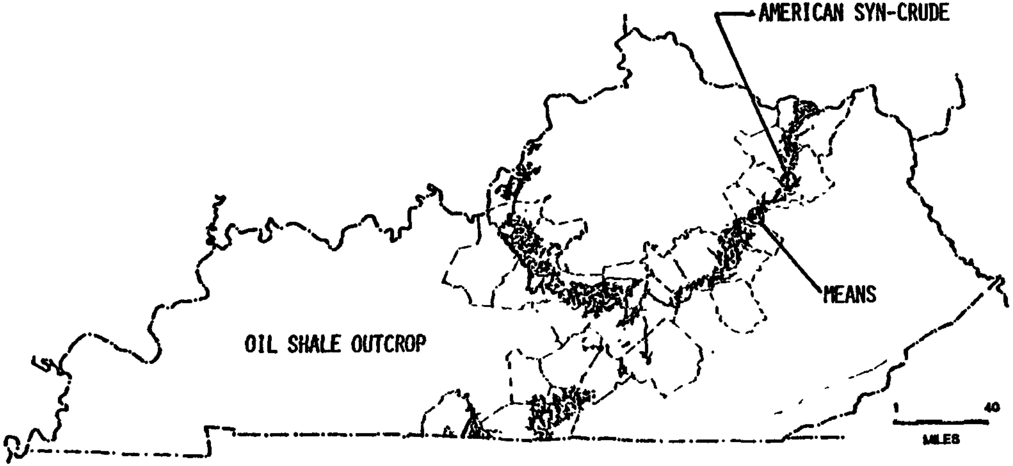
focus of development activities will continue to be on coal because of its importance to Kentucky's economy, but activities are being expanded in oil shale and tar sands development. The relative abundance of these three resources is shown in Table 1. When converted to a common basis of oil equivalency, the coal resource is approximately ten times greater than the outcrop shale resource and represents a much more concentrated energy form. The shale resource is approximately five times greater than the tar sands resource which have approximately equal energy densities. The funding priority that the Cabinet gives to these various resources is consistent with their relative abundance and potential economic importance to Kentucky.

Kentucky also carries out an extensive research program on its coal and other natural resources. That program has likewise focused on coal. Oil shale appeared in the budget for the first time in 1982 with a funding level of $460,000. The State's research program is carried out under contract by the Institute for Mining and Minerals Research (IMMR) of the University of Kentucky. The IMMR operates the state-owned Kentucky Center for Energy Research Laboratory. The resource, research, and sample programs reported here were carried out by that organization and detailed papers on each of these areas have been presented elsewhere.(2)(3)(4)

RESOURCE

Shales of the Mississippian-Devonian Age underlie virtually the entire State of Kentucky. The shales outcrop in a crescent area surrounding Central Kentucky, as Figure 1 shows, and dip beneath the surface on the outside of that crescent. Within that crescent, known geologically as the Cincinnati Arch, there is no shale present. Shale also outcrops in southcentral Kentucky in the Cumberland Saddle. The resource work has focused on the outcrop area and when completed in the next year, Kentucky will be the only eastern state with a definitive data base on shale. At the conclusion of that work we will have a reliable estimate of the recoverable shale reserves and, through over a hundred thousand analyses, the chemical composition and variability of the shale will be known. These will allow determination of the mining conditions and cost with a good degree of accuracy.

To accomplish this a comprehensive coring program was undertaken and has been completed. The first ten holes were in Lewis and Fleming Counties and supported as part of the Buffalo Trace Study. An additional 58 holes have been completed in the outcrop area as shown in Figure 2, under a variety of sponsorship, including the U.S. Department of Energy, the Kentucky Energy Cabinet, and through private support. The criteria established in



PROPOSED COMMERCIAL OIL SHALE
PROJECTS IN KENTUCKY

FIGURE 1

(FROM REF. 11)

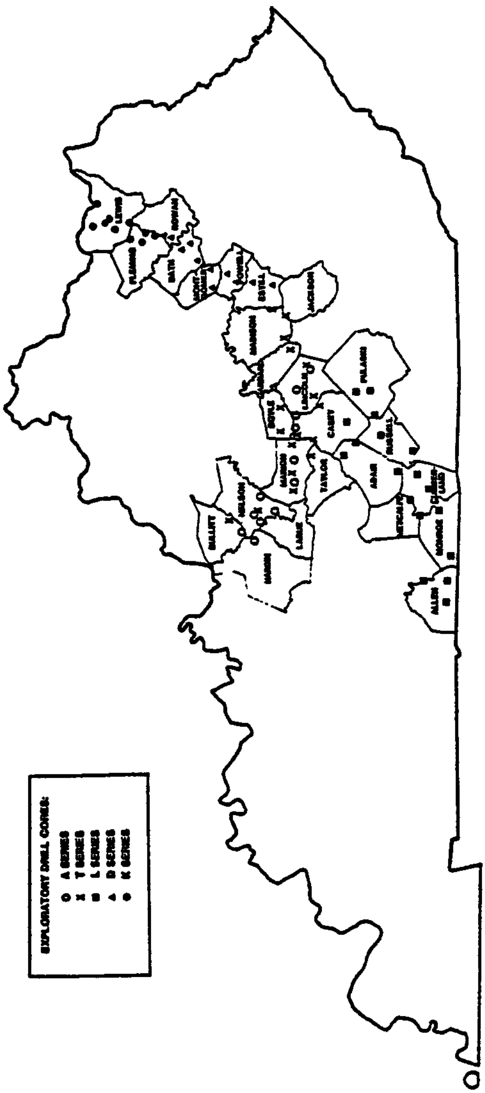


FIGURE 2

(FROM REF. 11)

the Buffalo Trace Study to estimate the potential, economically viable resource is being used throughout the study. Those criteria included a stripping ratio of no greater than 2.5 to 1 and generally an exclusion of shales that had a carbon content of less than 8%. Therefore, leaner and deeper shales are not being considered in the resource estimate. The development of resource quality maps continues, but based on work completed and some extrapolation, we know that there are at least 15 to 30 billion barrels of shale oil meeting the above criteria in-place in the outcrop area. This is a conservative number given the previous estimate by the Institute of Gas Technology (IGT) of 190 billion barrels of shale oil in Kentucky. However, even our more conservative figure is immense in itself and to put it in perspective would replace our current oil import level of three million barrels a day for a period of 15 to 30 years or could meet the 1990 synthetic fuel production goal of 10 million barrels per day for the next 20 to 40 years. This is clearly a national energy resource of such significance that it should not continue to be overlooked.

The characteristics of Kentucky shale are significantly different from the better known western U.S. shales. Devonian shales are a true clay base shale, whereas western shales are a carbonate rock or marlstone. This is a particularly significant factor in processing and in reclamation. The structure of the Devonian shale does not greatly change in retorting, whereas some western shales expand considerably and thus present more difficulties in reclamation. A more important parameter in comparing the two shales is its richness or the yield of oil from retorting. The most commonly used quality measure applied to shale is the oil yield by the Fischer-Assay method. That method was adopted for western shale for which it is better suited since it does not give an accurate picture of the energy recoverable from Devonian shale. This is because in addition to oil there is a considerable amount of light oil, gas and remaining unconverted carbon after retorting Devonian shale. The Fischer-Assay method is also inappropriate for eastern shale since it is based on specific heating rates and other parameters which were optimized for other types of shale. IMMR research has shown that modification of heatup rates and final temperatures in gas recovery significantly increase oil yields. Several parameters for Devonian shale and Colorado shale are compared in Table 2. This figure shows that the organic carbon content is approximately the same with the big difference being in the carbon present as carbonate in the western shale. The hydrogen is slightly lower for Devonian shale which is a key reason for difference in Fischer-Assay yields, whereas the heating values of the shales are about the same. The similarity of organic carbon content and heating values is a good indication that the potential recoverable energy from the two shales is also about the same. This data also explains why some processing technologies such as the IGT Hytort process can achieve 200% of Fischer-Assay yields and why IMMR has been able to achieve 160% of Fischer-Assay with fluid-bed retorting. The organic material is there. It is just a matter of supplying the right conditions and the right engineering to get it out.

There is also a significant difference in the characteristics of oil produced. The eastern shale oil has a significantly lower pour point and is more aromatic. Eastern shale oil also contains more naptha and thus can produce higher gasoline yields. Eastern shale oil also contains a higher amount of heteroatoms and considerably more sulfur. Detailed comparison has been presented elsewhere.(5)

RESEARCH

The research carried out by IMMR has focused on five areas:

- basic properties
- chemical and analytical methods
- process development
- materials evaluation
- environmental and reclamation

The work on the basic properties of shale has focused on the structure of shale, the characteristics of processed shale, and the rock mechanics. The characterization and analytical technique development has been important because of the inadequacy of the Fischer-Assay. An IMMR modified Fischer-Assay technique has been developed and published.(6) Studies have been conducted of the relationship of the carbon content of the shale with Fischer-Assay which show a very high correlation. An analytical pyrolysis technique which involves tandem pyrolysis and gas chromatography has been developed which offers several advantages.(7) First it allows control of heat rates and selective component isolation and analysis. Also it requires a much smaller sample than Fischer-Assay and is a more rapid technique. The uses of the technique are in geochemical evaluation, determination of optimum retort parameters and simulated retorting. Efforts are underway to develop correlations to predict oil and gas yield as a function of heat-up rate and shale chemistry. The product oil characteristics are being examined by simulated distillation and by analytical examination of the hydrocarbon structure with the objective of characterizing the product as a synfuel and determining the upgrade requirements. The effect of varying retort conditions on oil quality is being examined and the composition of the gases evolved during retorting is being determined.

Process development work being done by IMMR has the objective of increasing yield and determining optimum process conditions. Both direct thermal retorting and fluid bed retorting experiments are being carried out. Retorting has been carried out under Fischer-Assay conditions to establish a baseline and with steam injection which has yielded up to 25% over Fischer-Assay. The use of rapid heat-up with a sweep gas has produced an additional 20% yield. Also the effect of thermal retorting with a sweep gas has also been evaluated. The focus of the process development effort has been in fluidized bed retorting which has been carried out at three scales, a quarter-inch bed diameter, an inch and a half diameter retort, a three inch retort and in a cold flow model. The near term objectives of those studies are to determine the effect of bed temperature on oil yields, the effect of decreased residence time, and the effect of the presence of steam.

The IMMR material evaluations program has included alloy coupon exposure in retort environments during eastern oil shale processing. Coupons have been installed on a pilot steam retort, in the Kentucky Center for Energy Research Laboratory fluid-bed retort, in the Battelle Columbus retort, and in the Rockwell International retort. The objective of this program is to develop a materials performance data base which will allow selection of materials for commercial plant construction.

The work in the environmental and reclamation area has focused on a study done under contract by IMMR for the Kentucky Natural Resources and Environmental Protection Cabinet. A report on that work entitled "The Chemical and Engineering Properties of Eastern Oil Shale" (8) was completed last year. For that study oil shale was sampled at six locations in the Kentucky outcrop to obtain a wide geographic distribution. The major elemental oxides and trace elements were determined for all the samples. A portion of each sample was retorted and the spent shale subjected to a variety of tests including leaching studies, reclamation studies and determination of the engineering properties of the spent shale for reclamation purposes. It was found that the retorted shale would not be classified as hazardous under the Resource Conservation and Recovery Act criteria. The most potentially severe problem that was identified with the spent shale was a potential to generate acid water because of the sulfur content. However, this is believed to be amenable to control using techniques similar to those used by the coal industry.

SAMPLING AND SYMPOSIUM PROGRAMS

During the past two years IMMR has collected a number of small samples for research purposes and larger tonnage samples for pilot scale testing. The objective of the sampling program is to collect large, well-documented samples of Kentucky oil shale for use within the Kentucky Center for Energy Research Laboratory and for use by outside research and testing organizations. Samples have been supplied to each of the projects receiving U.S. Department of Energy support in the $1,000,000 study of innovative technology for eastern oil shale program. Those organizations are Rockwell International, Gulf Science and Technology, and Battelle Columbus Laboratory. Smaller samples have been provided to Ashland Oil, Mobil, Texaco, Los Alamos Laboratory, Cities Services, New Brunswick Research Council, and others.

In 1981 the Kentucky Energy Cabinet and IMMR cosponsored the first symposium on eastern oil shale to promote the visibility of that resource and its development and to provide a forum for the exchange of technical information and data. The first meeting was very successful with over 300 registrants and over 40 technical papers. The 1982 conference was similarly successful with over 200 registrants and 45 papers. Indications are that this year's conference, which is planned for October, will have broad-based support, since the technical program committee has been expanded to include a variety of interests from across the nation. The scope of the meeting has also been expanded to include shales around the world which are similar to eastern U.S. shales. The proceedings of the conferences are published and available through IMMR.

REGULATION DEVELOPMENT

As a result of leasing activity in 1979-1980, the 1980 Kentucky General Assembly directed the Kentucky Natural Resources and Environmental Protection Cabinet to "develop regulations for oil shale operations to minimize and prevent adverse effects on the citizens and the environment."

Oil shale operations were defined to include mining, retorting, and upgrading. There were little data available, therefore, the format of the State's coal surface mining regulations was used extensively. A research contract was issued to IMMR to determine the chemical and engineering properties of retorted shale. The bulk of the regulations was filed in June of 1981, and continue to be added to and modified. Basically, they require permits and bonding for shale operations. They are similar to coal regulations but differ in some important aspects. There is no requirement to return land to original contours and no petition process is proposed for designation of lands unsuitable. However, the major difference that has been proposed but not yet adopted is that projects must be able to demonstrate, using technical data from eastern shale, the impact of their operations or be restricted to less than 100 acres per year.

PILOT PLANT PROGRAM

Following the Buffalo Trace Study which confirmed that a large oil shale resource did exist in Kentucky and could be converted to a synthetic fuel with potentially viable economics, the objective of establishing a pilot plant in Kentucky was established. A pilot plant was deemed necessary as a step to hasten commercialization, since the key uncertainty was the performance of eastern shale in a retort. A joint venture concept was developed for a pilot plant project which would be flexible enough to accommodate a variety of retorting concepts and mining technologies.(9) The size was to be in the 25-150 tons per day range which would allow mining on a sufficient scale to generate a credible data base, produce sufficient product oil and spent shale for testing purposes. The joint venture team consisted of Cleveland Cliffs Company, Davy-McKee Engineering Company, IMMR, and the Kentucky Department of Energy Research and Development. In 1981 this group visited 18 energy companies, including oil companies, technology development companies, resource companies, and energy development companies. The proposal was received with varying degrees of enthusiasm, but three major obstacles to the project emerged. There was a general problem with the multi-purpose facility because of the protection of proprietary positions. Also, there was generally a low awareness of the potential of eastern shale and budgets in the synthetic fuels area were retricted. Near the completion of that effort, the opportunity arose to relocate the Paraho 25 ton per day pilot unit which had lost its Anvil Points lease. The Kentucky Energy Cabinet undertook a study to determine the cost of relocating that facility under a cost-sharing agreement with the Davy-McKee Company and Paraho. The scope of that study included not only relocating the Paraho Pilot Plant which had capability for direct and indirect heating, but also the Marathon capability for steam-injection. The design incorporated a second retort for the next step of development of the Paraho technology, the combination heating mode and two site options in Kentucky were considered. When the cost of that project came in at $8.9 million, Kentucky determined that it would have to have additional private sector sponsors to go forward with the project. Paraho was under contractual commitments to proceed with tests, therefore, there was no time to try to bring in additional participants and the pilot plant was relocated in Colorado. The State remains interested in participating in a pilot activity, but only jointly with private participation.

COMMERCIAL DEVELOPMENT

Since 1979 four companies, Phillips Petroleum, Breckinridge Minerals (Southern Pacific Petroleum), Pyramid Minerals (American Syn-Crude), and Addington Oil Company have leased some 360,000 acres of oil shale properties in Kentucky.(9) This represents only 30-40% of the available outcrop area in Kentucky. Of these four companies, Phillips announced plans to pilot the Hytort technology on eastern oil shale jointly with the Institute for Gas Technology.(10) That project has not been sited to date. Two of the remaining companies have developed commercial projects which have been proposed to the Synthetic Fuels Corporation. The two projects were proposed in the third round solicitation of the SFC and both were passed conditionally through the maturity test in February 1983, and will be brought up for project strength review in July. The condition placed on both projects is that the design shale feedstock tests that are currently planned be successfully completed. Both projects have requested SFC loan guarantees and price supports. The two projects are located in the northeast section of the oil shale outcrop in Kentucky (Figure 1) with the American Syn-Crude project located in the Fleming-Rowan County area and the Southern Pacific Petroleum project located near Means in Menifee County. The participants in the Means project are Southern Pacific Petroleum, the primary sponsor, Dravo Corporation as the manager and contractor, Gibbs-Hill as the environmental consultant, Morgan-Stanley & Company as the financial consultant, with technical and other support being provided by the IMMR and Kentucky Energy Cabinet. The Means project would process 50,000 tons per day of Devonian oil shale into 13,400 barrels per day of synthetic crude oil. The Dravo travelling circular grade oil shale retort would be used to extract the oil which would undergo onsite hydrogenation to a synthetic crude oil product. A single above-ground retort having a diameter of 320 feet and a height of 100 feet would be used. Product gases would be used to produce 165 MW of electric power on site, of which 107 MW would be used for plant and mine operation and 58 would be sold. The capital cost of the project is estimated to be $1 billion in December of 1982 dollars. The peak construction employment would be 2400 while the permanent operating force would be 750, including mining operations. The mine would require 165 acres per year from three moving pits and would be the largest mining operation in the U.S. The schedule calls for construction in the first quarter of 1985 with start-up in the third quarter of 1987 and full production by the second quarter of 1988. The Commonwealth of Kentucky has participated in the Means project by producing a 30-ton shale sample for testing and carrying out research programs, including shale characterization, leaching studies on retorting shales, a study of carbon content as a function of particle size and water and soil studies. The sample is being taken in the spring of 1983 for a 2,000-ton test at Dravo's pilot plant in Cleveland to be run in May.

The participants with American Syn-Crude in its project are the Davy-McKee Corporation and Stone and Webster Engineering as the contractors; Skelly and Loy as the Mine Design Engineer; and technical support provided by IMMR and the Kentucky Energy Cabinet. The project would process 13,484 tons per day of Devonian shale into 4,160 barrels per day of crude shale oil, 10.3 million standard cubic feet per day of high Btu gas, and 94 tons per day of commercial-grade sulfur. The technology used is the Petrosix process developed in Brazil which is a direct heated vertical shaft retort. Two retorts 36 feet in diameter would be used, which is a moderate scale-up from the 18 foot unit operating in Brazil. The capital cost of the project is estimated at $355 million in as spent dollars, employment estimates are 850 for the peak construction and 250 for the permanent operating force. Construction could then begin in the second quarter of 1987, followed by start-up in the second quarter of 1989. The Commonwealth of Kentucky has participated in the Amercian Syn-Crude project by assisting in the production of a 120-ton shale sample, carrying out shale characterization work, and cosponsoring the test at Petrosix to prove the performance of the shale in the Petrosix process and generate the design data. The schedule for the project is to carry out a 13-ton test at the Petrosix plant in Sao Mateus, Brazil, in the second quarter of 1983, followed by a 20,000-ton test in 1984. The 13-ton test will be carried out in the two-ton per hour bench scale Petrosix retort which is eight inches in diameter while the larger test would be conducted in the 18-foot retort. The retort performance would be evaluated over a range of eight operating variables. The project scope also includes determination of crushing and handling characteristics and analysis of oil, gas, water and spent shale. The project deliverables are a report of the test data and results, Petrosix evaluation of oil shale performance, recommendations for further tests in the larger retort, preliminary process design of the commercial module for the Kentucky site and samples of oil, water and spent shale. Of the estimated $500,000 project cost, the Kentucky Energy Cabinet is providing $200,000 with the balance being provided by American Syn-Crude, Stone and Webster, and Petrobras.

CONCLUSION

The extensive resource work carried out to date has determined that there is a sizeable oil shale resource base in Kentucky. The properties of that resource are known in sufficient detail to estimate its performance under various retorting conditions, the amount of characteristics of product oil, and engineering aspects of reclamation with the spent material. The State of Kentucky has committed financial and other resources to promote and facilitate the development of its shale resource, including both research and demonstration activities. Two commercial projects have been proposed to the Synthetic Fuels Corporation and are receiving support from the Commonwealth of Kentucky. It is in the national interest that the immense energy potential of eastern oil shale be recognized and that projects be supported to convert that resource into needed liquid fuels.

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MICROBIOLOGY FOR ENHANCED OIL RECOVERY

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ABSTRACT

The U. S. Department of Energy has sponsored several projects to investigate the feasibility of using microorganisms to enhance oil recovery. Microbes from the Wilmington oilfield, California, were found to be stimulated in growth by polyacrylamide mobility-control polymers and the microbes also can reduce the viscosity of the polyacrylamide solutions. Microbes have been discovered that produce surface active molecules, and several mixed cultures have been developed that make low viscosity, nonwetting, emulsions of heavy oils (°API < 10). Microbial processes are being developed in Canada for applications to heavy oil deposits, in China for enhanced recovery of light oils and successful field tests have been conducted in Romania and Arkansas.

INTRODUCTION

Scientists of the Bartlesville Energy Technology Center of the Department of Energy became actively involved in microbial research in 1970 while investigating the fate of chemical compounds injected into deep wells. Work was sponsored at the Department of Microbiology of Oklahoma State University to determine if it would be feasible to inoculate organic waste injected into subsurface formations with bacteria which could decompose toxic substances underground through metabolic processes. If such a technique could be developed, the toxicity of the injected wastes could be neutralized to eliminate a possible, although remote, hazard that would result if the injected wastes should find a conducting path to the surface at some future date. Several new aspects of microbial growth under conditions of elevated temperature and pressure were discovered. However, the general conclusion drawn from this work is that biodegradation of organic compounds will be very limited, or entirely absent, under the conditions existing in deep geologic formations used for liquid industrial waste disposal. The work was concluded in 1976 with the publication of a Final Report (1).

In the mid-1970's enhanced oil recovery became more prominent and the Bartlesville Energy Technology Center began a series of large field tests to determine the applicability of various methods for enhanced oil recovery (EOR) that had been proposed in laboratories. Large quantities of chemical compounds were considered for use in the oilfields, such as synthetic surfactants, organic polymers, caustics, etc. Used in tonnage quantities, it was felt that the chemicals posed a potential for creation of considerable environmental hazards. Consequently, the Bartlesville Energy Technology Center of the Department of Energy (BETC) initiated a literature review to examine the toxicity of these chemicals(2), and also began a new study at Oklahoma State University in July 1979 to determine the biodegradation of EOR compounds (3,4,5). In addition, a book by J. B. Davis (6) and the Proceedings of the 1976 Engineering Foundation Conference (7) provided an overall review of the literature emphasizing the potential for microbial EOR. Consequently, the Department of Energy issued invitations to several microbiologists and engineers to attend a forum at San Diego, California, August 29 - September 1, 1979 (8), to discuss the feasibility of using microorganisms for EOR.

After the San Diego Forum, BETC developed a plan for a very basic research program to investigate microbial EOR (MEOR), which is illustrated in Figure 1. Three objectives were established: (1) discover proper-

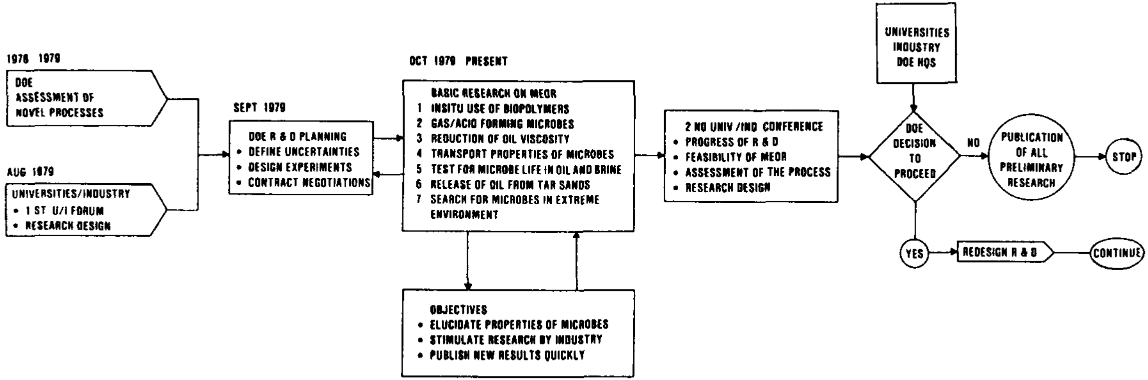

FIGURE 1. Complete research program plan for microbial enhancement of oil recovery.

ties of microbes that are applicable to petroleum recovery and processing, (2) stimulate research by the petroleum industry, and (3) publish all results of the research effort as rapidly as possible in the BETC Quarterly Progress Reviews, and sponsor conferences on MEOR.

Seven Projects were initially planned. The first five projects shown in Figure 1 were funded at four universities and a research company. In addition, the Engineering Foundation was contacted to assist in sponsoring a second conference on MEOR to serve as a means of publishing results from the MEOR research around the world and to discuss direct applications to the petroleum industry. The conference, which was held at Afton, Oklahoma, May 1982, was attended by scientists from twelve foreign countries who presented papers and took an active part in discussions which were held every night. The papers have been edited for publication by BETC as a book and a review of the papers was prepared for publication in Oil and Gas Journal (9).

DEPARTMENT OF ENERGY MEOR RESEARCH

Biodegradation of Compounds Used in EOR (Oklahoma State University). The biodegradability of various chemical compounds that are proposed for use in EOR have been studied and the results are now being prepared for publication. Two very significant discoveries were made in May 1981 that began with a discussion of an unexpected field result from the injection of a polyacrylamide solution as a mobility control experiment at a depth of 1000 meters in the Wilmington Field, Long Beach, California. The expected increase in oil production from the EOR procedure was not realized, but a four-fold increase of hydrogen sulfide production occurred. Samples of oil and brine from the test site were taken to Dr. Mary Grula at the University with a request that she isolate the bacteria and test them for possible ability to decompose polyacrylamide and use it as a carbon/oxygen/nitrogen source in their metabolism. Dr. Grula found that the growth of bacteria isolated from the oilfield samples was indeed stimulated by the polymer and the bacteria reduced the viscosity of the polymer solution. In addition, the anaerobe *Desulfovibrio* and an unclassified, pink pigmented, bacterium were isolated from the well samples. The new bacterium was found to be facultative (grows either aerobically or anaerobically) and to produce a viscous biopolymer which allows this organism to form impermeable aggregated clusters of cells. The biopolymer also can trap other organisms making the entire group almost impenetrable to common biocides used in treating wells. If such associations exist in petroleum reservoirs where bacteria are creating adverse effects on oil production, biocides to eradicate the bacteria would have to contain an agent capable of dispersing the protective biopolymer. Work is still in progress to study these bacteria since they may play an important role in the reduction of sulfates and degradation of polyacrylamide.

Isolation and Screening of Anaerobic Clostridia for Characteristics Useful in EOR (Oklahoma State University). The objectives of this project are to: (1) obtain selected microorganisms for use in enhanced oil recovery; screen the bacteria qualitatively and quantitatively for their ability to produce gases, acids, solvents, and surfactants; (2) test the bacteria for their ability to grow under conditions that exist in oil wells; (3) determine if a desired inoculation sequence of bacteria exists for promotion of oil production; and (4) conduct field tests with the bacteria to determine actual applicability to MEOR.

Many species of the genus *Clostridium* that can grow in 5% sodium chloride and produce solvents, acids and carbon dioxide have been isolated and characterized, and recently a species of *Clostridium* that produces low-molecular-weight surfactant-type compounds under anaerobic conditions has been isolated. Thus, the first two objectives have been achieved and work this year is concentrated on the development of several pilot field tests that will be conducted in Oklahoma and Kansas to test the cultures for ability to clean out the pores of the producing zone near the wellbore by *in situ* formation of acids and solvents, and pressurization of the zone with carbon dioxide. In addition, oil displacement field tests, using wells that have reached the economic limit of production by waterflood, also are planned. The details of all of the results will be published in the BETC Quarterly Progress Reviews.

Use of Microorganisms in EOR (University of Oklahoma). This work was designed to isolate bacteria that produce biopolymers and biosurfactants as metabolic products and examine the potential for *in situ* use of these microbes to enhance oil recovery by selectively plugging high-permeability zones. The investigators also are to make a search of existing petroleum data files to define reservoirs suitable for MEOR. This project was initiated as a joint effort between the Departments of Microbiology and Petroleum Engineering, and they have established a special laboratory to be used jointly by both Departments to conduct the work.

The initial search of petroleum data files, using as the most important criteria: temperature, salt concentration, and permeability, revealed that about 15 percent of the oil reservoirs listed for Oklahoma could be used for microbial treatments, but California is the most promising with an estimated 55 percent of the reservoirs treatable by MEOR.

The search for microbes that produce polymers and surfactants was conducted using both aerobic and anaerobic screening procedures. Many of the bacteria that were isolated belong to the genus Bacillus. Some of the bacteria are spore formers which is a characteristic very useful to *in situ* transport of bacteria since the spores are less than one micron in size and do not have extracellular products associated with them. Five aerobic cultures that will grow in 2 percent sodium chloride and produce biopolymers were isolated. Two of the cultures were chosen for more intensive study since both produced large quantities of a biosurfactant. Both belong to the species *Bacillus subtilis*. Cultures grown with crude oil above the aqueous phase reduce the interfacial tension to less than one dyne/cm. Cultures of the bacteria isolated from the Wilmington oilfield at Oklahoma State University also are being used at the University of Oklahoma to examine the possible use of these bacteria to plug high permeability zones and methods for stimulating their growth at simulated petroleum reservoir conditions of temperature, pressure and fluid saturations.

Oil displacement experiments were made using sand-packed columns. The glass tubing was 45 cm long and 2.5 cm in diameter. It was packed with white quartz, saturated with water, then the water was displaced with oil; the column was then waterflooded to establish a residual oil saturation in a water-wet sand environment. An actively-growing culture of the biosurfactant-producing bacteria was flowed through the core. The oil was released in droplets which migrated to the top of the column. A control sand pack through which only the saline solution was pumped at the same rate showed no release of the residual oil. Detailed information on the development of this culture, the properties of the biosurfactant, and the results of various experiments is being prepared for publication in the 1982 Annual Report of this project.

The Application of Microbial Processes for the Reduction of Viscosity of Heavy Crude Petroleum (University of Georgia). This project was initiated to concentrate on three distinct phases: (1) the isolation of microorganisms which exhibit a metabolic capability to reduce the viscosity of highly viscous crude oil, (2) determination of the environmental and nutrient requirements for maintenance of culture viability of any organisms that can reduce the viscosity of oils, and (3) a final phase to determine the mechanisms involved in the microbial modification of heavy oil with characterization of the products of oil degradation and biopolymers that may be produced by the bacteria.

One aerobic culture of mixed bacteria has emerged which is capable of reducing the viscosity of an oil (API° 8.0) by 95 percent, from 2,825 to 163 centipoises measured at 60°C. This reduction in viscosity is accompanied by a two- to three- fold increase of the volume of the mixture because the bacteria produce a biosurfactant (glycolipid) which emulsifies the oil. The emulsion is non-wetting to glass and steel, and exhibits properties of a thixotropic liquid (it exhibits a decrease in apparent viscosity with time of application of shear force, but upon standing the original highly viscous condition returns).

Samples of the bacterial-produced emulsion were tested with gas chromatography (GLC) and distillation(10). The GLC analysis, figure 2, shows that culture H-13 consumed the paraffins in the oil in the range from about C-12 (the lowest molecular weight paraffins present) to C-32. The treated sample was separated from all traces of water and microbial products by thin-layer distillation and then subjected to a number of tests. There was an increase in the density of the oil due to removal of the paraffins, and the boiling temperature range was higher for the treated sample - indicating again that the volatile paraffins had been removed. The analysis for sulfur and nitrogen showed that these bacteria did not destroy the chemically bound elements which are generally found in the polynuclear aromatic ring structures. The oil was increased in density and distillation temperature range by removal of the paraffins, but this is a negligible price to pay for the large beneficial change in rheological properties. If the culture can be grown in a stock tank at the production site, pumping and transportation of the oil from that point to the refinery would be greatly facilitated.

This year work will be concentrated on the third objective which is to thoroughly characterize the biosurfactant and to develop a method for its synthesis. Chemical synthesis of the compound would eliminate the difficulties attendant to production of large quantities of the cultures, and would make the material commercially available for other possible EOR processes such as addition to waterfloods and steamfloods.

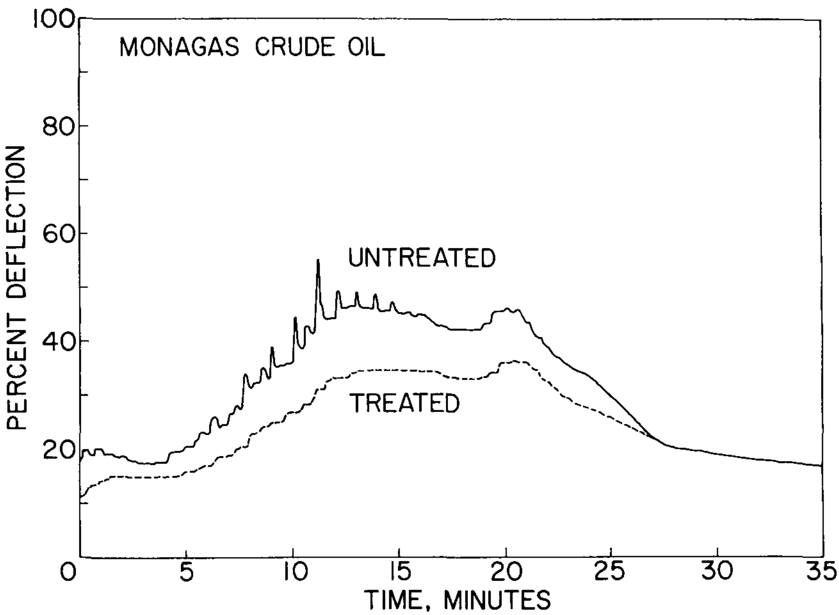

Figure 2. Gas chromatograms of Monagas crude oil and the microbially treated oil.

Bacterial Transport Through Porous Media (University of Southern California). This project was initiated to examine the interaction between bacteria and geological porous media containing oil and brine, and to develop a theory of the transport phenomena of bacteria through porous media at reservoir conditions.

Very strong adsorption of microorganisms on sandstone cores has been observed. The injection of cells resulted in formation of a cake at the inlet indicating strong adsorption of the cells, since they are 5 to 20 times smaller in size than the average pore diameters of the sandstones used. However, spores of bacteria are easily transported through sandstone because the spores possess an inert, rigid wall. Spore-forming anaerobic bacteria may be the only type of bacteria that can be transported efficiently through a petroleum reservoir unless a solution or solvent is found that can inhibit the adsorption of live cells. The formation of extracellular polymeric materials and ionic charges on the surface of the bacteria play a larger role than the physical size of the bacteria in determining their passage through porous rock.

Research continues on this project to develop a better understanding of the causes of microbial adsorption to sedimentary rocks, development of a theory of the mechanisms, and development of methods to facilitate the transport of the microbes. In order to contact trapped oil with bacteria that have favorable oil displacement properties, the microbes must be transported from a wellbore to locations deep within the reservoir. This may be a pivotal factor for applications of microbes to specific reservoirs.

OILFIELD APPLICATIONS OF MICROBES

Lloydminster Oilfield in Canada. The ultimate recovery by primary and secondary methods from the Lloydminster Oilfield in Canada (Alberta/Saskatchewan border) is estimated to be no higher than 8 percent. The oil in place is about 2.5 billion cubic meters of oil at 600 meters depth with an API gravity range of 3-17°. Hence, this is a significant target for EOR. The principal impediment to production of the oil is water channeling due to the high viscosity of the oil (400 - 9,000 centipoise at 25°C), and the high permeability (4 darcies), and poorly consolidated sand. Jack (11), et al suggested that there are two approaches to MEOR than can have a significant impact on the oil recovery efficiency: (1) repressurization with gases produced by microbes in situ and (2) release of oil in portions of the reservoir by anaerobic fermentation of molasses which can cause *in situ* production of gases, acids, surfactants, and solvents. Production of these metabolic products depends on the type of bacteria, the type of nutrients, and the immediate environmental conditions. Preliminary laboratory experiments conducted by Jack et al (11) indicated that the major mechanism for oil release from the sand is the nascent formation of gas *in situ* which brings about a marked decrease of oil viscosity accompanied by swelling as the nascent gas dissolves in the oil. The effect is very pronounced in the laboratory, but may not be as efficient under field conditions because of low gas-transfer rates and the absence of convective mixing.

According to Jack et al (11), emulsification of the viscous crude oil *in situ* is not feasible at this stage of development because transport of bacteria within the formation and mixing of the biopolymer with the crude oil in place are not technically feasible. However, emulsification of a produced heavy oil as it is pumped from the wells to storage tanks, or in the tanks by active microbes, would facilitate later transfer from the tanks, and in pipelines.

Field Applications in China. Zhang and Qin (12) stated that because the oil fields that have thus far been discovered in China are very heterogeneous and contain viscous oils, the approach to MEOR in China has been the development of microbial cultures that can utilize crude oil hydrocarbons to make bioproducts which may aid in recovery of oil as waterflood additives, preparation of drilling fluids, and other oil field operations. They have found that aerobic fermentation of crude oil yields a biosurfactant which readily forms a microemulsion with crude oil and water which has a greatly reduced viscosity compared to the crude oil. When the products of fermentation are mixed with crude oil having a viscosity of 2,500 centistokes, in a 1:1 ratio, the viscosity of the resulting mixture is between 12 and 46 centistokes. Zhang and Qin postulated that biosurfactants of this type will aid in recovery of residual oil when added to injected water and this will be the emphasis in the future.

Zhang and Qin (12) briefly described a second microbial product which they called a thickening agent because its intended use is to plug high-permeability zones by injection of this product. It is a viscous polysaccharide obtained from a Gram-positive, non-spore forming, rod with a tendency toward V-shaped association. They have tentatively named the microbe *Cornynebacterium gummiferm*. The bacteria produce copious yields of polymer from mixed paraffins as their sole carbon source, but show a considerably reduced yield when grown with a crude oil substrate.

The thrust of future work in MEOR in China is to develop technology for the production of the biosurfactant and biopolymer in the oil field where they will be used as additives to injection water.

Field Applications in Romania. MEOR research in Romania was carried from the laboratory stage directly to field trials with work starting in 1972 by Lazar et al (13). The work began with a concentrated effort to isolate bacteria that were adapted to reservoir conditions. This began by isolation of bacteria from produced water, but the search was widened to include well bottom-hole mud, soils around oil wells, food processing wastes, and others. Oil displacement experiments showed conclusively that the microbial cultures obtained from produced waters and sugar processing plants were more effective. The mixed cultures were adapted to reservoir conditions and increased to concentrations of 10^7 - 10^9 bacteria/ml. Species identified in these mixed cultures were *Pseudomonas*, *Escherichia*, *Arthrobacter*, *Mycobacterium*, *Micrococcus*, *Peptococcus*, *Bacillus*, and *Clostridium*. These mixed cultures were more efficient in releasing oil than the pure strains or bacteria obtained from other sources.

Seven oil fields in Romania were inoculated, but only two of the oil fields responded with an increase of production ranging from 16-200 percent. The well with the 200 percent increase produced 6.7 m^3/month over a period of several years and then rose to 20.0 m^3/month average production after inoculation of the field. The increased oil production continued for more than one year and is currently rising. Lazar attributes the failure of the other five reservoirs to respond to microbial treatment to heterogeneity, low permeability, and high salt concentration.

Monitoring of the microbial population in the produced waters after inoculation showed that about six months after inoculation the microbial count began to increase from 10^4/ml to 10^6-10^9/ml while a nutrient solution of 2 percent molasses was being injected constantly. One year after the nutrient injection stopped, the microbial counts in the produced waters dropped to 10^3-10^4/ml. The results indicate that the inoculated microbial culture multiplied in the reservoir and migrated from the injectors to the producing wells.

Field Test in Arkansas. Yarborough et al (14) described a successful field test using *Clostridium acetobutylicum* in a two-spot pattern with 120 m between wells. The formation is a loosely consolidated sand of high permeability containing up to 16 percent carbonates at a depth of 700 meters. Core tests indicated a maximum residual oil saturation of 8.5 percent and the test well production averaged 3 m^3/month prior to the inoculation.

Injection of a 2 percent molasses solution and bacteria commenced in July 1954 and was continued until November at an average rate of 25 m^3/D; a total of 800 liters of bacteria culture was injected in this period. In October, 3 months after the initial injection, significant changes occurred at the production well. The oil recovery increased from 3 to 10 m^3/month and continued through the duration of the test (May 1955). Production of acids, carbon dioxide and methane also occurred at the production well in October 1954. The cumulative production of acid and CO_2 over the test period was 35,000 kg of acids and 5,700 m^3 (11,000 kg) of carbon dioxide. No quantitative measurement of the methane production was made. Hydrogen was not detected, and the authors believe that it may have been used by other bacteria in the reservoir and was involved in the production of much of the methane.

SUMMARY

1. Bacteria were isolated from the Wilmington oil field in California at a depth of 1,000 meters that are capable of reducing the viscosity of polyacrylamide solutions, and they produce biopolymers that may inhibit treatment by biocides.

2. Salt-tolerant bacteria of the genus *Clostridium* have been isolated and shown to produce relatively large amounts of carbon dioxide and low-molecular-weight organic solvents in 5-7 percent salt solutions. Spores of these bacteria exhibit very little adsorption on sandstone rock samples, thus the spores can penetrate deep within a petroleum reservoir to germinate where most needed.

3. A mixed culture has been developed which produces a biosurfactant when fermented aerobically with crude oil that causes a decrease of the oil phase viscosity of 95 percent and produces a non-wetting (on glass or steel) emulsion. The bacteria were shown to utilize the paraffins of the oil to make the extracellular biosurfactant.

4. Laboratory experiments indicate that some bacteria can be injected into high permeability zones to increase the sweep efficiency of a waterflood.

5. Living cells have been found to be strongly adsorbed on sandstone which restricts the injection of non-spore-forming bacteria unless carrier solutions are developed that inhibit cell adsorption and thus allow deep migration of the cells into the oil reservoir.

6. Mixed bacteria cultures (Gram-negative, facultative rods) have been isolated that produce copious amounts of gas and are designated for possible respressurization of oil fields in Canada. A nutrient solution also was developed that aids in the injection of the bacteria by inhibiting adsorption. A second growth medium activates the bacteria to produce a biopolymer *in situ*.

7. An extracellular polysaccharide prepared from aerobic fermentation of crude oil has been developed in China and is proposed as a waterflood additive to increase sweep efficiency and oil recovery.

8. Two of seven field tests in Romania with mixed cultures of bacteria that were acclimated to reservoir conditions resulted in a two-fold increase of production. Oil production continues to rise in the two fields that responded positively.

9. A field test in the United States with *Clostridium acetobutylicum* resulted in a 250 percent increase in production from a two-spot injection test and production of 34,000 kg of acids and 5,700 m^3 of carbon dioxide during the 9-month test period.

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MOBILITY CONTROL AGENTS

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A. Abstract

This paper reviews five field tests that CLD Group, Inc., supported by the DOE, Santa Fe Energy, Conoco, and Texaco, has completed in the heavy oil fields of California.

The five tests are summarized below:

Test #1 - was a test with low concentration chemical slugs and air injection in the Midway-Sunset Field; the purpose was to determine whether the additives could improve the performance in a pattern where the oil-steam ratio had reached an uneconomic limit. Incremental recovery was significant at 65,000 barrels.

Test #2 - was a combination slug and continuous chemical injection test with nitrogen in the Cat Canyon Field; the purpose was to examine the capacity to block a massive steam channel in a deep, hot, and highly viscous reservoir. Although oil recovery was minimal, the water cut in the key well decreased by 12%.

Test #3 - was a verification test involving the injection of highly concentrated chemical and large volumes of air to reform the "foam block" and achieve major areal steam diversion in the same pattern as used for Test #1. A large amount of additional oil, 46,000 barrels, was recovered.

Test #4 - was a high concentration slug test using nitrogen as the inert gas in the San Ardo Field; the purpose was to reduce the non-productive circulation of steam through the oil depleted steam zone. Although the incremental recovery was only 3,500 barrels, a definite response was measured in the oil-steam ratio and in the diversion of steam.

Test #5 - was an expansion of Test #4 using continuous injection of chemical to reduce steam channeling in the second ring of production wells. This test succeeded in recovering an additional 21,500 barrels of oil.

All of the tests can be deemed technical successes, as they succeeded in demonstrating the validity of the process by (1) diverting steam (2) increasing oil recovery, (3) increasing the oil-steam ratio and (4) improving the water cut - although in some cases only by a minor amount. In addition, the two tests in the Midway sunset field were economic successes.

B. Introduction

The purpose of enhanced oil recovery (EOR) is to (1) mobilize oil left behind by more conventional processes and (2) displace it to the producing wells. The two EOR processes that currently appear to have the most promise are steam drive, mainly for heavier crudes, and carbon dioxide (CO_2) flooding, mainly for lighter crudes. Both of these methods consist of injecting fluids (steam or CO_2) with much lower viscosity and greater mobility than the oil. Thus, while they are good agents for mobilizing additional oil, they are bad at displacing the producible oil.

The higher mobility of steam and CO_2 gives rise to two problems. The injected steam and CO_2 will not have a good volumetric sweep of the reservoir, but will (1) finger through the reservoir and (2) rise to the top, Figures 1 and 2. All the oil is therefore not contacted and the efficiency of the process is lowered. Moreover, once low permeability paths through the reservoir have been created, steam or CO_2 injected subsequently will preferentially flow through these paths, thus reducing the efficiency of the EOR process further.

FIGURE 1

VISCOUS FINGERING

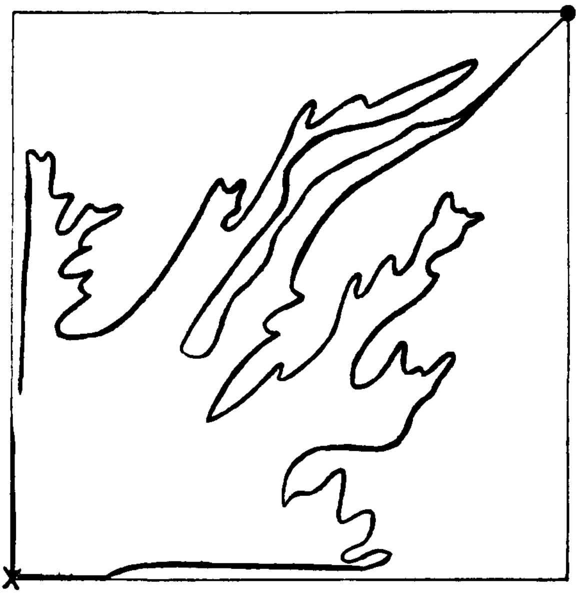
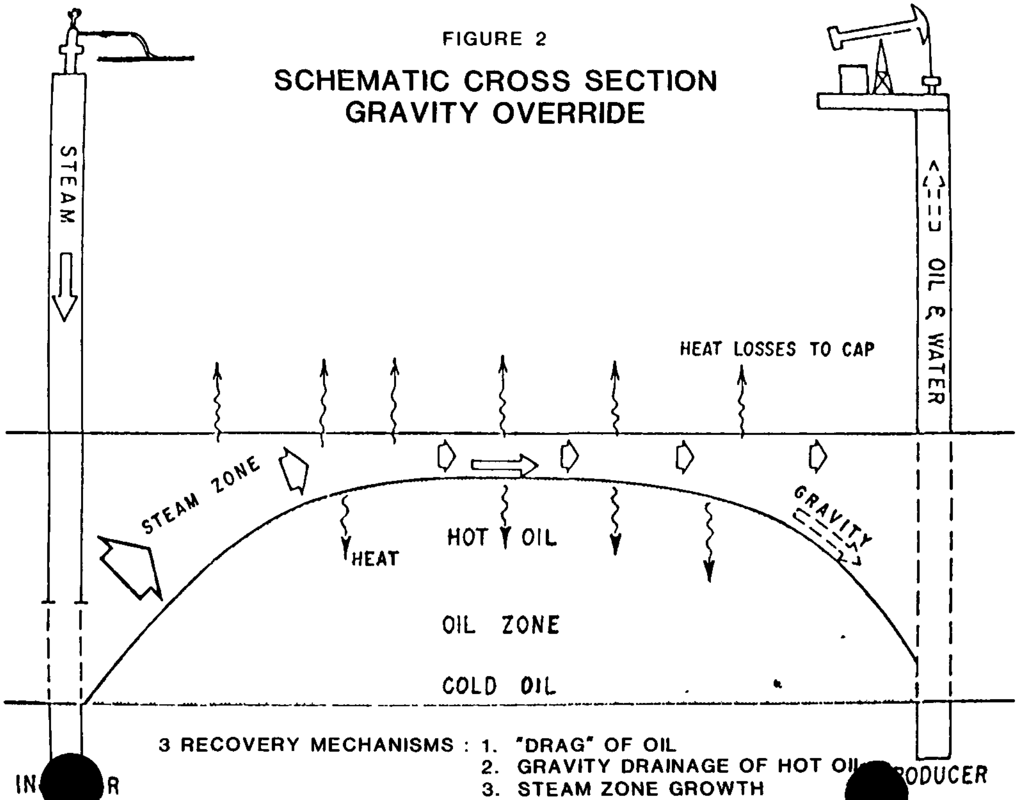


FIGURE 2

SCHEMATIC CROSS SECTION
GRAVITY OVERRIDE



3 RECOVERY MECHANISMS : 1. "DRAG" OF OIL
2. GRAVITY DRAINAGE OF HOT OI[redacted]
3. STEAM ZONE GROWTH

The purpose of mobility control agents is to block these highly permeable paths and displace the steam or CO_2 into areas of the reservoir that previously have not been swept.

C. Background

In October 1979, the CLD Group, Inc. entered into a contract with the U.S. Department of Energy to test the applicability of foaming chemicals for controlling mobility in steam drive operations. The project consisted of basic laboratory R&D supplemented by five field tests in California.

The initial laboratory testing involved screening chemicals for thermal stability and testing methods of emplacing them in a porous media. Tests were also conducted in a 16-foot sandpack to verify the emplacement techniques and the capacity of the chemical system to control the mobility of injected steam.

The laboratory testing showed that the chemical additives had to contain some non-condensible gas which must be co-injected or injected alternating with steam. Both air and nitrogen were used as the non-condensible gas. The advantage of air is its availability and low cost. Because steam and air cannot be injected simultaneously due to the potentially dangerous corrosive environment resulting from such a combination, the chemical was injected with steam as slugs alternating with air. With nitrogen as the non-condensing gas, continuous and simultaneous injection of gas and steam is possible.

The field test locations were chosen to address two major technical problems encountered in steam drive operations, namely, the excessive channeling of steam through "thief" zones, and the progressive increase in steam flow through oil-depleted, already swept zones.

The five tests are: two with Santa Fe Energy in the Midway-Sunset Field, one with Conoco in the Cat Canyon Field, and two with Texaco in the San Ardo Field.

D. Field Tests

A series of five tests were designed to examine the laboratory-derived steam with additive system under highly instrumented and controlled field conditions. Four tests examined the use of steam with additives under different reservoir settings, as well as different variations of the process. The fifth test, a verification field test, was designed to technically prove the preferred steam with additive system under normal field operating conditions.

1. Test #1. Midway Sunset Field

A 12-month test of steam with additives was completed in October 1981 in a heavy oil field, the Midway-Sunset Field, Kern County, California, on a lease belonging to Santa Fe Energy. The pilot pattern 590-21 is shown on Figure 3. The purpose of the test was to determine whether the use of additives could revive a steam drive pattern at the end of its economic life.

Steam soak was initiated in the pattern in late 1970 and a steam drive started in 1972. By 1979, the pattern had reached its economic limit when CLD and Santa Fe reached an agreement to conduct a steam with additives pilot test. Injection of a high temperature resistant chemical and compressed air started in November 1980 and continued through April 1981. Monitoring of performance continued through October 1981.

A significant improvement in performance occurred during the test. The three-month moving average of oil and water production and the oil-steam ratio from Pattern 590-21 through the first test are shown on Figure 4. The pattern responded in February 1981, three months after injection of air and chemicals started. After the injection was terminated in April 1981, the three-month average pattern performance continued to show a response through October 1981, when the test was stopped.

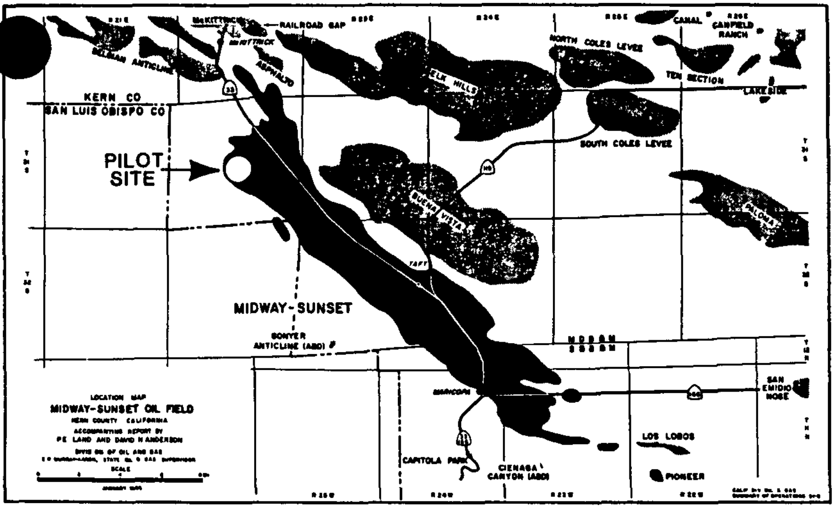
The improvement in performance is summarized as follows:

- Oil production in the pilot area increased four-fold, from a six-month average of 18 barrels per day prior to the test in 1980, to an average of 72 barrels per day from February through October 1981; recovery reached a peak of 144 barrels per day in July 1981. During the 9-month period, February through October, a total of 20,000 barrels of oil were produced from Pattern 590-21.

- The oil-steam ratio, the key measure of economic performance, increased five-fold from a base of 0.04 in the last six months of 1980 (the pre-test base year) to over 0.20 for the last six months of the test (May-October, 1981). Overall, the oil-steam ratio, for continuous steam injection into Pattern 590-21, averaged 0.15 for February through October, 1981.

FIGURE 3

MIDWAY-SUNSET OIL FIELD AND PILOT PATTERN



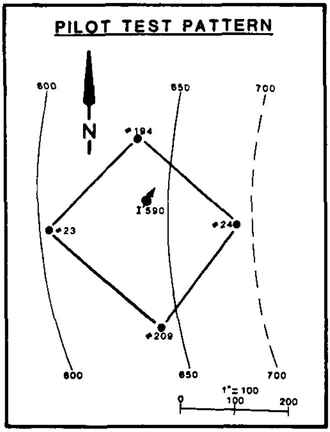


FIGURE 4

PERFORMANCE FROM PATTERN 590-21

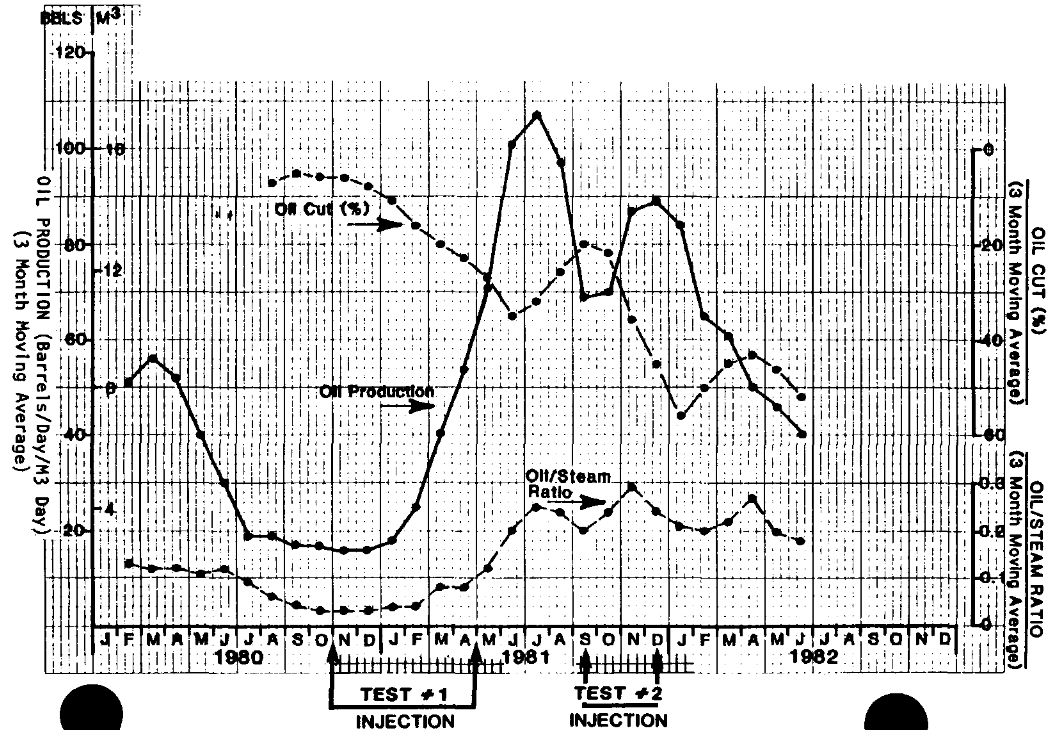
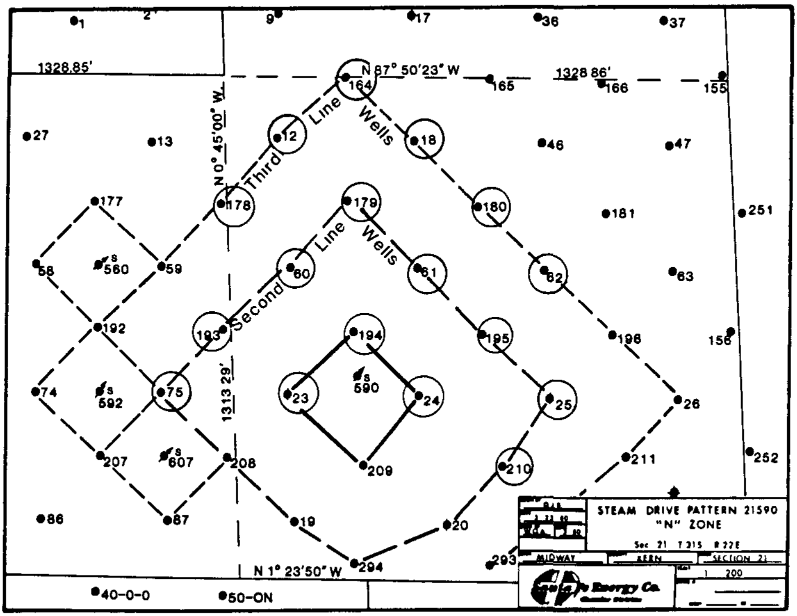


FIGURE 5

STEAM DRIVE PATTERN 590-21 "N" ZONE

(MIDWAY-SUNSET OIL FIELD)



164 Wells with Response to Steam with Additives.

- The oil-cut in Pattern 590-21, an important measure of steam efficiency in an unconfined pattern, improved steadily from a base of 6% (for the last six months of 1980) to 25% for February through October, 1981.

- Deterioration in the pattern performance was first observed in August 1981, three months after injection of chemical and air were terminated; oil production in October 1981, at the end of the pilot test, was 60 barrels per day.

During the test, a total of 22,000 pounds of high temperature resistant chemical, 2,000 Mcf of air, and 180,000 barrels of steam were injected. The key ratios of pounds of chemical, Mcf of air and barrels of steam per barrel of incremental oil (Pattern 590-21 only) are as follows:

	Pattern 590-21
• chemical/oil	1.5 #/Bbl
• air/oil	0.1 Mcf/Bbl
• steam/oil	7 Bbls/Bbl

The main pattern and the surrounding pattern, second ring and third ring wells involved in the test are shown on Figure 6. The wells that responded to steam drive with additives are circled.

Eight second ring and six third ring wells had improvements in the oil-steam ratio, the water cut, and the rate of oil production, as summarized below.

- The oil-steam ratio for the eight second ring wells increased from 0.27 in 1980 to 0.70 (February-October); similarly, the oil-steam ratio for the six affected third ring wells increased from 0.74 in 1980 to 0.85 (February-October).

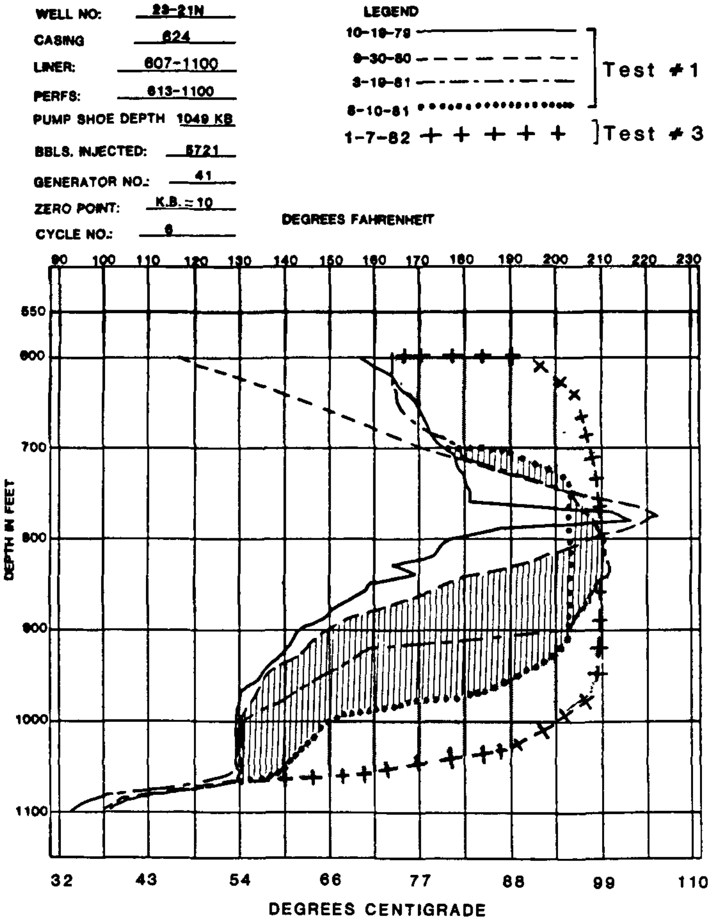
- Oil production in the affected second ring of wells increased by 29,000 barrels and in the six third ring of wells by 16,000 (February-October) over the established historical decline curve.

Temperature surveys taken in the key updip well (#23) during the test are a further indication of its success show a progressively widening steam profile, Figure 6, indicating that the override is being reduced.

FIGURE 6

TEMPERATURE PROFILE IN PATTERN WELL

(PATTERN 590-21)



C. Test #2. Cat Canyon.

The second test was a six-week injection test in a deep, hot formation of the Cat Canyon Field with very viscous oil. The location of the field and the pilot test site are shown on Figure 7.

The purpose of the test was to determine whether injection of additives could plug a wide, high permeability channel that provides a direct communication between the injection and the nearest updip production well. Radioactive tracer tests indicated that 90 to 95% of the 300 barrels per day of injected steam was going directly to this nearest producer, Well 38.

This field test represented extreme limits:

- The steam temperature and pressure were 460°F and 450 to 500 psia, thus testing the thermal limits of the chemical.

- The oil viscosity in the formation was over 25,000 cp, at original reservoir conditions.

- The high permeability, "hot region" channel, was estimated to be approximately 30 feet thick and approximately 100 feet above the main oil sand.

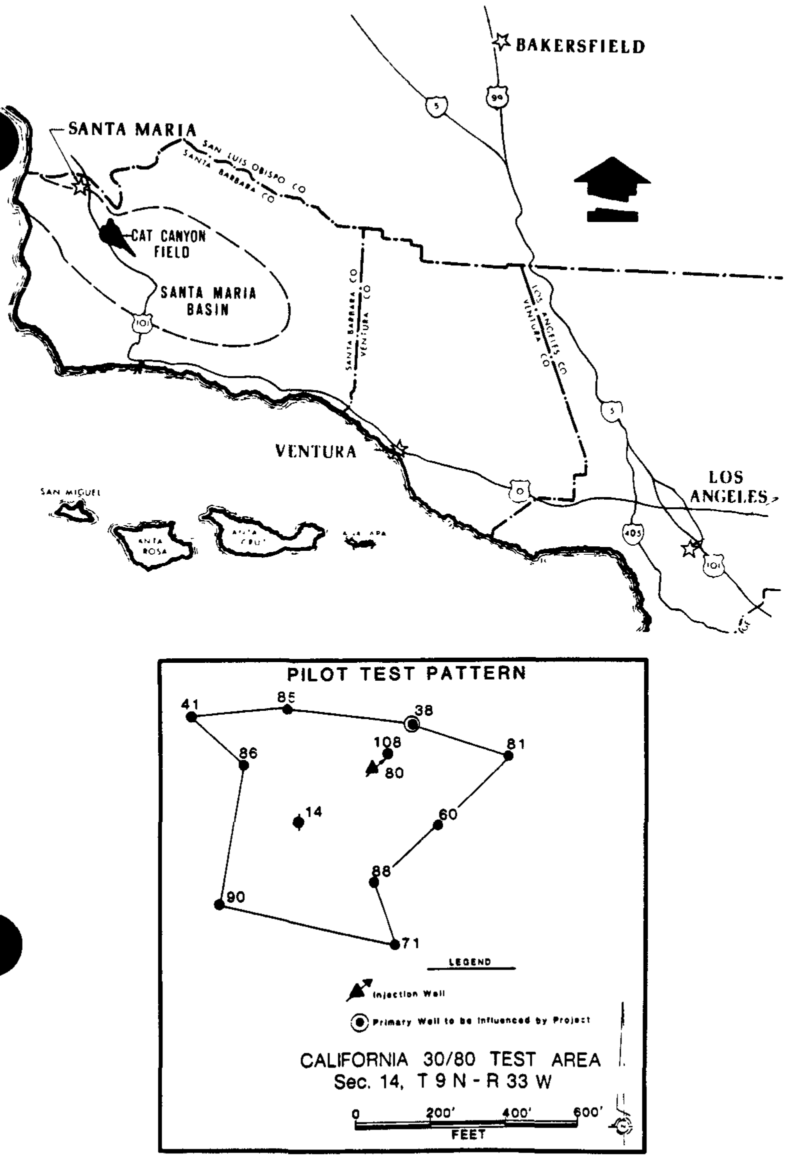
The field test was initially scheduled to be a four-week injection of foaming chemicals. It was subsequently extended to a six-week test between May 1 and mid-June 1981. For the first two weeks, an average of about 500 pounds of chemical and 10,000 scf of nitrogen were injected per day in the form of a slug followed by continuous injection of nitrogen at 15,000 to 25,000 scf per day plus steam at 300 barrels per day. To obtain improved entrainment of the chemical in the steam, reduced injection rates were used during the last four weeks of the test. The chemical amount was increased to about 700 pounds per day with nitrogen injection fluctuating between 10,000 and 25,000 scf per day.

During the six-week test, a total of 26,500 pounds of chemical and 870 Mcf of nitrogen was injected.

Several changes in the performance of the pattern were measured that indicate some positive response from the chemical injection. Some of these changes, however, may be due to other influences:

FIGURE 7

CAT CANYON OIL FIELD AND PILOT PATTERN



- The water cuts in most wells declined, as shown in Table 1, and there was a significant change in the water cut of the key well, California 38; changes in the water cuts of the other wells may be due to shut-in of offset steam soaks.

- Initial data indicated an increase in the injection pressure, from 440 to about 550 psig during the six week injection period while the steam injection rate was maintained at 300 B/D. Since temperature data did not corroborate this change in pressure, it is judged that the observed changes in pressure were due to faulty pressure gauges.

Overall, in spite of certain positive indications, it does not appear that the injection of the chemical/inert gas was able to completely block the large steam channel above the oil column.

3. Test #3. Midway-Sunset Field

The site of the third test was rescheduled from another pattern back to Pattern 590-21. The purpose of the test was to determine whether the effectiveness of the additive system could be re-established and the increased oil production replicated, and achieving a better distribution of steam throughout the test pattern.

A higher concentration and larger volumes of chemicals were used than is the first test.

Injection of chemical and inert gas started in late September 1981, following a steam soak in three of the four production wells and one of the second pattern wells. Chemical was injected 3 days per week as a slug with the steam, while compressed air was injected each day. Air injection was discontinued while the chemical was being injected. In total, 21,315 pounds of chemical, 1.7 MMscf of air and 150,000 barrels of steam were injected.

Incremental oil production was 46,000 barrels; 6,000 barrels from the pattern, 28,000 barrels from the second ring and 12,000 barrels from the third ring. Figure 4 summarizes the three-month moving average for oil production, oil cut, and oil-steam ratio for both of the tests in Pattern 590-21.

TABLE 1

PRE-AND POST-TEST WATER CUTS

(CAT CANYON – PATTERN CAL 80)

WELLS, #	AT START OF TEST (%) (4–30–81)	AT END OF TEST (%) (6–13–81)	CHANGE IN WATER CUT (%)
38	96	84	(12)
41	95	78	(17)
60	82	77	(5)
71	87	64	(23)
81	85	81	(4)
85	46	46	–
86	42	38	(4)
88	58	45	(13)
90	47	11	(36)

This second test in the same pattern was a successful verification test as the performance of the pattern improved substantially; oil production reached a peak of 108 barrels per day in December 1981. Chemical injection was then terminated and the steam injection rate reduced by one half. Oil production consequently declined, reaching 40 barrels per day in June 1982.

The oil-steam ratio, the key economic measure of performance, averaged 0.22 (November 1981 through June 1982) for the pattern. In addition, the oil cut remained highly favorable, averaging 46% during the test. The oil-steam ratios were also favorable in the affected surrounding second and third ring wells. In the first half of 1982, the oil-steam ratio was 1.16 and 0.59, respectively. Temperature surveys of Well 23 showed that the steam zone continued to increase and extended over the entire interval at the end of the test, Figure 6.

The four pattern production wells showed a much more balanced flow of fluid and production of oil during the second test. Figure 8 compares the oil volumetric flow for Pattern 590-12 before the injection of chemicals, during the first test, and during the second test. Both tests succeeded in increasing oil recovery significantly from 17 barrels per day; average production was 72 barrels per day in the first test and 61 barrels per day in the second test. However, in the first test, 65% of the production occurred from Well 194 to the north, while in the second test, production was much more evenly distributed among the four producing wells.

4. <u>Tests #4 and #5. San Ardo Field</u>.

Tests #4 and #5 were in the Aurignac formation of the San Ardo Field, Monterey County, California, on a Texaco, Inc., lease. Figure 9 is a structure map that shows the location and a diagram of the pilot.

The project involves one central injector, Well 85A, five closely spaced producers covering 4 acres (2.5 acre spacing) , and eight surrounding production wells covering 20 acres (2.5 acre spacing). Prior to the tests, the pattern was at an advanced stage of depletion with water cuts of over 90%.

The purpose of these tests was to show whether (1) the performance of a pattern that had reached its economic limit could be improved and (2) the improvement could be extended to the larger spacing.

FIGURE 8

ANALYSIS OF OIL PRODUCTION AND DIRECTION OF FLOW

(PATTERN 590-21)

Total Oil Volumetric Flow (B/D)

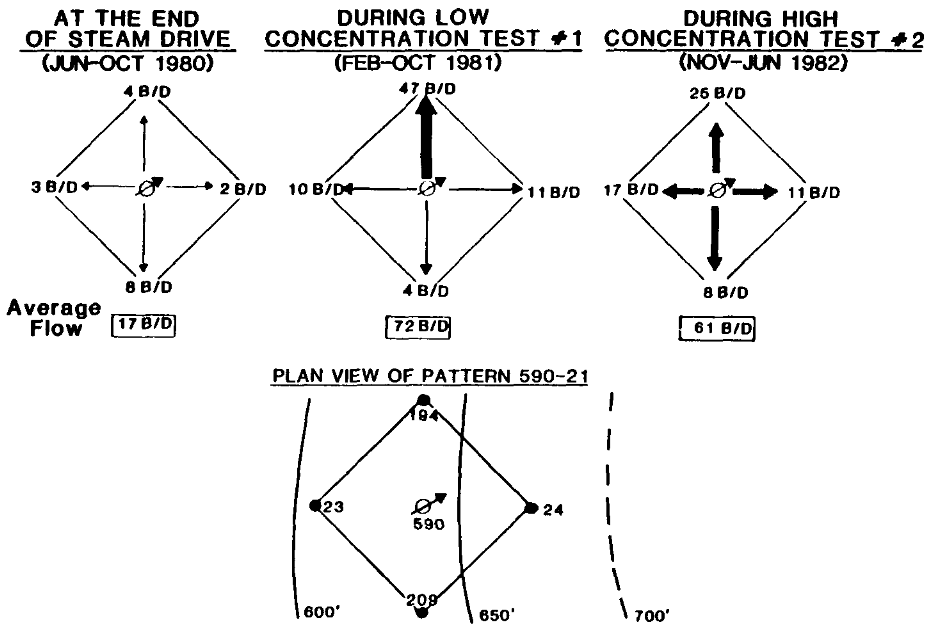
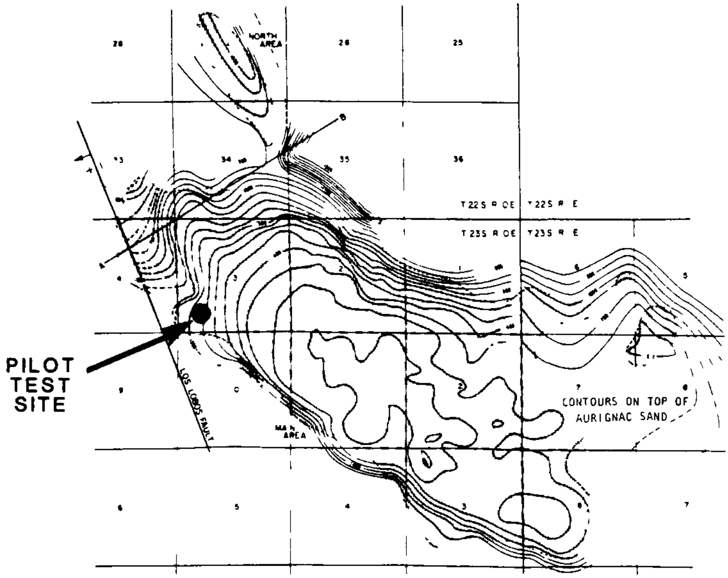


FIGURE 9

SAN ARDO OIL FIELD AND PILOT PATTERN

(MONTEREY CO. CALIFORNIA)



CONTOURS ON TOP OF LOMBARDI OIL SAND OR EQUIVALENT

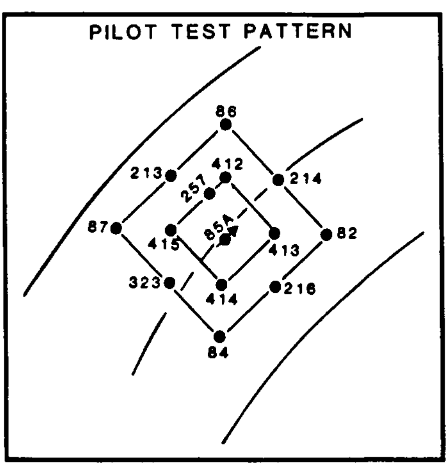


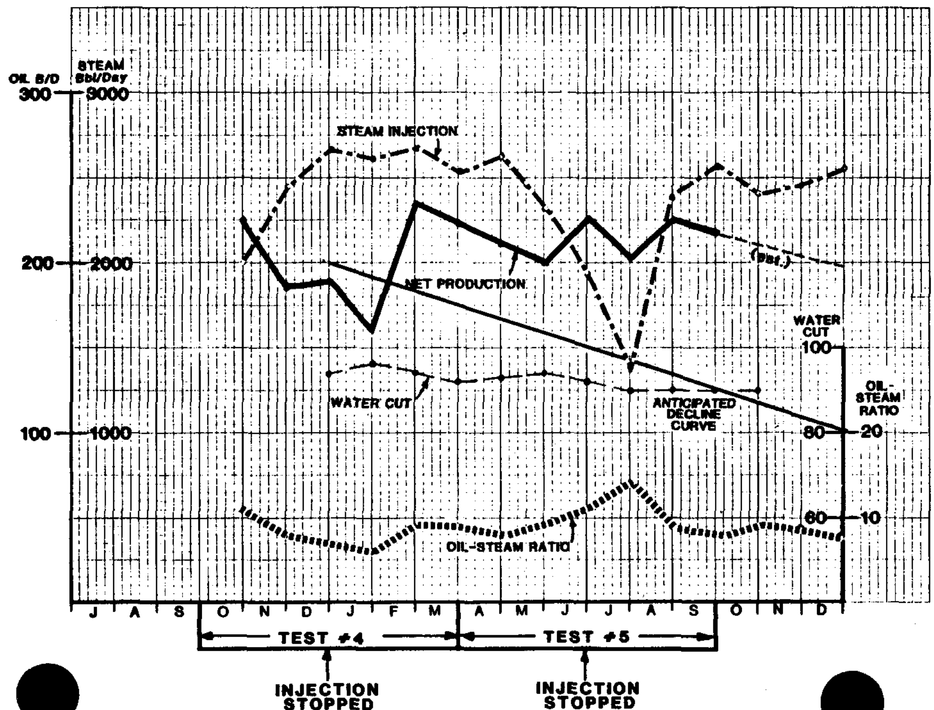
TABLE 2

TESTS 4 AND 5 - PRODUCTION AND INJECTION SCHEDULE

	TEST 4	TEST 5
A. OIL PRODUCTION		
Oil Production, MB	3.5	21.5
B. INJECTION MATERIALS		
Chemical, Mlbs	69.3	116.9
Nitrogen, MMcf	4.6	6.7
Steam, MB	450	620

FIGURE 10

STEAM INJECTION INTO AND PERFORMANCE OF ROSENBERG 85 PATTERN



Injection of chemical and nitrogen for Test 4 started in early October 1981 and continued to December 24, 1981. After three months of monitoring, Test 5 started in April 1982. Injection of chemical and nitrogen was stopped on June 14, 1982 while steam injection and monitoring continued. The injection period for each test lasted three months, but about double the volume of chemical was injected for Test 5; [illegible],300 pounds versus 116,900 ponds. The amount of oil produced and additives injected for Test 2 and 5 are shown on Table 2. The resulting ratios of material injected per barrel of oil are summarized below.

	Test 4	Test 5
Chemical/oil, lbs/B	19.8	5.4
Air/oil, Scf/B	1,310	32
Steam/oil, B/B	130	30

A significant improvement in results was obtained for Test 5. The larger amount of additives injected in Test 5 could be a main reason for this.

During the tests, the key indicators of technical success, the oil production, water cut, and oil-steam ratio, all showed an improvement, Figure 10. The first few months after injection of chemical and nitrogen started, the oil-steam ratio continued to decline. Then it slowly increased, reaching 0.11 in June when injection of additives was discontinued. Similar improvements were noticed for the water cut and oil production. The changes are summarized below.

- In Test 4, the second ring responded in February 1982, a month after chemical injection stopped, with increased oil production (to 235 BPD), a decrease in water cut (to 94%) and an improved oil-steam ratio (to 0.09). Incremental oil recovery was 3,500 barrels.

- For Test 5, injection of chemicals and nitrogen started again in April 1982. The second ring pattern responded in June with improvements in oil recovery (to 225 BPD), water cut (to 92%) and oil-steam ratio (to 0.11). Incremental oil recovery was 21,500 barrels.

The test results indicate that during Test 4, steam appears to have been diverted to the west and south, leading to increased oil production and an improvement in the water cut of the second ring wells. No improvement in water cut was measured in the pattern wells, probably because they were only completed in the bottom third of the formation.

MICROBIAL ENHANCED OIL RECOVERY

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The past decade has witnessed an ever increasing interest in the use of microorganisms for the purposes of enhanced oil recovery and/or production. This exploitation of microbial processes has become generally known as "microbial enhanced oil recovery" (MEOR) and, has, since 1975, represented the singular topic of three major conferences (1,2,3). Precisely what does MEOR represent? What is the current status of research and development? What potential exists for the eventual realization of applying microorganisms and/or their processes to the recovery of oil?

Enhanced oil recovery (EOR) research programs have emphasized thermal, miscible gas and chemical processes (surfactant and/or polymer) encompassing variations and combinations of these experimental techniques with varying degrees of success. A discussion on the application of microbial processes to oil production will necessarily be incomplete. Even as the petroleum engineer lacks complete knowledge on the chemical and physical structure of the oil reservoir, the microbiologist lacks basic information necessary for addressing possible role(s) microorganisms may play in enhanced oil production. Accordingly, research over the past half century has established a comprehensive literature in the fields of hydrocarbon and petroleum microbiology with recent advances relating to the physiological, biochemical and genetic properties of hydrocarbon-utilizing microorganisms (4,5). The application of this knowledge has yet to be realized in context of its direct application to EOR or oil production.

MICROBIOLOGICAL AND GEOCHEMICAL PROCESSES IN OIL RESERVOIRS

Information relating to the types of microorganisms that exist within the reservoir environment as well as their physiology are totally inadequate. Recent studies pertaining to the microflora of reservoirs have demonstrated the presence of diverse populations of microorganisms with the taxonomic classification and cataloguing of their various physiological and biochemical properties yet to be accomplished. The realization is self evident that reservoirs are not sterile, biologically refractory environments. It is of further interest that many bacterial isolates recovered from reservoirs of varying depths (1,000-10,000 ft) are obligate aerobes, requiring the presence of molecular oxygen for their growth and respiration. The sources of the indigenous microflora remain undetermined with possible point source contamination from surface origins or, alternatively, of subterranean origin.

The nature and quality of oil formations is highly variable, reflecting varying states of chemical maturation and alteration. Oil is typically formed at depths wherein temperature and pressure induce thermal transformation of organic substances present in source sediments. Such thermally-induced compositional changes are viewed as constructive processes, improving the quality of an oil by increasing the amount of light hydrocarbons while decreasing the concentration of heavy sulfur-, nitrogen- and oxygen-containing molecules as well as reducing the density and viscosity of the oil. Such positive geochemical processes are counteracted by destructive processes ranging from weathering and oxidative processes at or near the earth's surface to biodegradation by microorganisms. In fact, biodegradation is considered to represent a major destructive phenomena on oil. In this microbiological process, the first hydrocarbons subject to biodegradation are the n-paraffins, followed by isoparaffins, cycloalkanes and simple aromatics, and finally the polycyclic aromatic hydrocarbons and heavy asphaltenic structures. Oil biodegradation results in the concentration of non-hydrocarbon and heavy asphaltenic constituents, generating an oil of poorer quality (increased density and viscosity) than the original oil. Oil is susceptible, therefore, to significant chemical alteration through biodegradation and is recognized as the predominant mechanism whereby vast heavy-oil deposits are formed throughout the world.

WHAT IS MEOR?

The interest in MEOR concerns the application of microorganisms and specifically the exploitation of their metabolic processes to effect increased oil production from reservoirs of marginal productivity. MEOR becomes more directly applicable to tertiary recovery scenarios, although field situations might prevail where secondary recovery could be considered applicable. The principal considerations in MEOR are three-fold:

1. direct stimulation of existing microflora within the reservoir;
2. introduction of microorganisms with specialized physiological properties into the reservoir;
3. above-ground production of specific bioproducts and their subsequent use as chemically-enhanced oil recovery agents (CEOR).

Research and development has centered around three basic focal points, all directed towards eventual field testing and application:

1. Reservoir Microbiology
2. Biotransformation of Crude Oil
3. Bioproducts Applicable to EOR

A. RESERVOIR MICROBIOLOGY. Introduction of microorganisms or stimulation of microbial growth in the reservoir environment must consider the physico-chemical properties of the reservoir in terms of temperature, pressure, pH, salinity and general nutrient limitation and/or availability. Those microorganisms present in the reservoir have adapted to this environment successfully, although evaluation of their positive or negative physiological properties, relative to EOR have not been determined. The injection of specifically prepared microorganisms must be accompanied by adequate as well as appropriate nutrient supplies to ensure cell proliferation. If *in situ* oil represents the carbon source, then oxygen must be available to allow for the growth of obligately, aerobic hydrocarbon-utilizing microorganisms, since bacteria are unable to metabolize hydrocarbons in the absence of molecular oxygen. Injection of anaerobic microorganisms or stimulation of the indigenous, anaerobic microflora would necessitate supplying fermentable substrates (e.g., molasses, whey) for cell proliferation. Numerous reports exist concerning the growth of sulfate-reducing bacteria and the souring of sweet crudes, plugging phenomena and other deleterious effects resulting from microbial action (6). However, evidence has been reported indicating the utilization and release of oil by microorganisms in subsurface environments by the injection of air and mineral nutrients (7).

B. BIOTRANSFORMATION OF CRUDE OIL. Over three decades of basic research on bacterial metabolism of hydrocarbons have demonstrated that the ability to degrade a wide spectrum of hydrocarbons is a common and widespread characteristic of the microbial world. To date, approximately 60 known hydrocarbons have been studied with respect to their metabolism by microorganisms. Additionally, numerous reports are available describing the ability of microorganisms to grow at the expense of crude oils (8). The microbial alteration of oil results in decrease of oil volume, loss of n-paraffins, light aromatics and napthenes, increases in the nitrogen-, sulfur-, oxygen-containing constituents, increase in optical activity, increase in asphaltene content, enrichment in ^{13}C content and a corresponding increase in density. Collectively, these changes are distinct from changes occurring by other oil-altering processes, with bacterial-mediated alterations of oil being opposite to those changes resulting from geochemical maturation. The chemical composition of oil has been demonstrated to influence the dynamics of its biodegradation, influencing not only the types of bacteria capable of metabolizing the oil but also the growth characteristics (9). For example, a microbial population enriched in low-quality oil readily utilized high-quality oil. However, populations enriched in high-quality oils were unable to effectively grow on low-quality oil. The effects on oil quality must, therefore, become of paramount importance when considering either stimulation of the indigenous, hydrocarbon-utilizing reservoir microflora or the direct injection of such microorganisms into reservoirs. Regardless, evidences strongly indicate a down-grading of oil quality as a result of microbial action.

C. BIOPRODUCTS APPLICABLE TO EOR. A variety of chemicals are used for improved water flooding or tertiary recovery operations which include surfactants, coagents, high-viscosity water-soluble polymers and sequestering or sacrificial agents. Types of bioproducts of current applicability to EOR are biopolymers, biosurfactants, coagent alcohols, and sequestering agents (saccharinic acid, Krebs cycle intermediates, siderophores and dipicolinic acid), all of which can be produced microbiologically. Only biopolymers and specifically xanthan has been applied to EOR. Desirable physico-chemical characteristics of biopolymers concerning their effectiveness in field performance are shear stability, resistance to shear thinning, high viscosity, resistance to biodegradation, compatability with reservoir brine and rock structure, stable viscosity over a wide range of temperature, pressure, pH and salinity, water-solubility, storage stability and cost-effective production.

Extracellular biopolymer (polysaccharide) production is an ubiquitous characteristic of microorganisms with several of these biopolymers of commercial value and utility (10). The usefulness of these bacterial polysaccharides rests in their unique physical and chemical properties as determined by the individual component sugars and linkage relationships. At this time, three bacterial polysaccharides of commercial importance are in large scale production - dextran, polytran and xanthan. Xanthan is currently the most important polysaccharide for EOR. Xanthan, polyacrylamide, modified starches and cellulose derivatives (carboxymethylcellulose) are also used as additives to oil drilling muds. Optimistic projections for use and application of xanthan to EOR have yet to be realized, with the petroleum industry remaining largely in an experimental-research mode of testing and problem-solving of numerous disadvantages. Some of the problems associated with xanthan and/or polyacrylamide are listed in Table 1.

TABLE 1

PHYSICAL CHARACTERISTICS OF POLYACRYLAMIDE AND XANTHAN FOR EOR

CHARACTERISTIC	POLYACRYLAMIDE	XANTHAN	IDEAL
Viscosity thickening	10-15 cps at 500 ppm	10-15 cps at 500 ppm	20 cp at 10 ppm
Salinity maximum	1500-2000 ppm	10,000 ppm	15,000 ppm
Maximum reservoir temp.	175-200°F	200-225°F	250°F
Divalent ion maximum	200 ppm	5000 ppm	5000 ppm
Reservoir permeability	50 md	50-100 md	100 md

The physical properties considered as nominally ideal are not uniformly matched by available polymers. Other disadvantages have become apparent as the result of field studies in complex reservoir environments; namely, disappearance of polymer from produced waters and biodegradation. Polyacrylamide and xanthan have been demonstrated to be microbiologically altered by microbial activity.

The limited availability of diverse microbial polysaccharides for testing and evaluations of EOR has become apparent. This fact is further overshadowed by the conceptual potential of xanthan to EOR and the real potential for its application in EOR. Table 2 lists selected polysaccharides of microbial origin for which reasonable data-bases have been established as to their rheological characteristics.

TABLE 2

SELECTED POLYSACCHARIDES OF MICROBIAL ORIGIN

MICROORGANISM	BIOPOLYMER
Pseudomonas species	polysaccharide
Azotobacter vinelandii	alginic acid
Xanthomonas campestris	xanthan
Methylomonas mucosa	polysaccharide
Erwinia tahitica	Zanflo
Azotobacter indicus	PS-7
Alcaligenes faecalis	Curdlan
Leuconostoc mesenteroides	Dextran
?	Polytran
Aureobasidium pullulans	Pullulan
Rhinocladiella mansonii	polysaccharide
Acinetobacter RAG-1	Emulsan

The application of surfactants to EOR represents an active development area in oil production. Consideration and/or application of biosurfactants and/or bioemulsifiers has generally been ignored or overlooked, primarily for the lack of a definitive and cohesive literature on the subject. Sources, types and applications of biosurfactants have been reviewed in broad generalities and in relation to bacterial hydrocarbon metabolism (4,11). The production of surface active compounds by microorganisms has been recognized for years. A systematic characterization of these types of bioproducts has, however, been slow to emerge in the scientific literature. Recent sutdies in many laboratories have documented the production of a variety of surfactants produced by microorganisms (Table 3). The development and application of biosurfactants may represent valuable and potentially useful compounds in addressing a number of recovery and production problems in the oil industry. Although biosurfactants are not currently used or being considered by the industry, potential applications are suggested as aids for micellar flooding, viscosity reducers and rock-wetting agents.

TABLE 3

SURFACTANTS OF MICROBIAL ORIGIN

MICROORGANISM	SURFACTANT
Corynebacterium hydrocarboclastus	proteo-lipid-carbohydrate complex
Corynebacterium lepus	corynemycolic acid
Candida petrophilum	proteo-lipid
Bacillus subtilus	surfactin (proteo-lipid)
Rhodococcus erythropolis	trehalose dimycolates
Acinetobacter sp. HO1-N	lipoprotein
Arthrobacter paraffineus	trehalose lipid
Pseudomonas aeruginosa	rhamnolipid
Candida tropicalis	polysaccharide-fatty acid complex
Torulopsis bombicola	sophorolipids

STATUS OF MEOR

The status of MEOR currently resides at a basic level of research and development. Few research projects have developed to where field testing and assessment are deemed of value. However, a number of research programs have provided information of potential import and application in a MEOR based technology. The following discussion will review current approaches from two points of view: injection of microorganisms into the oil-bearing strata and production of bioproducts as CEOR agents.

A. INJECTION OF MICROORGANISMS. Over the past 20 years, sporadic reports from Eastern Europe have described the stimulation of depleted reservoirs to significant production values by the injection of anaerobic microorganisms and a fermentable substrate such as molasses.

Such reports have served to stimulate a renewal of interest in the reactivation of depleted and capped wells, which exist in the thousands, to oil-producing wells through microbial stimulation. An empirically developed fermentation process has indicated the release of significant amounts of new oil from depleted reservoirs (2).

The oil release technique is described as an inexpensive, anaerobic fermentation designed to function within the reservoir with the process having applicability within closely defined physical parameters. It consists of the injection into the reservoir of anaerobic, spore forming Bacillus and Clostridium species along with an aqueous solution of fermentable carbohydrate (milk whey, molasses, sawdust). The basis for this process lies in the formation of metabolic byproducts such as CO_2, CH_4, H_2, N_2, short chain organic acids, alcohols and ketones. The gases cause a partial repressurization of the reservoir as well as reducing oil viscosity through solubilization; whereas, organic acids react with reservoir carbonates to form additional CO_2 and the alcohols and ketones exhibit surfactant effects. Such reports indicate the need for controlled and critical assessment of bacterial fermentations in depleted oil reservoirs and the effect on oil production.

Injection and/or stimulation of microorganisms with respect to the feasibility of MEOR is dependent upon the mobility of microorganisms within a geologic formation containing oil, water and salt. Bacteria must be transported from the well-bore to locations deep within the reservoir. Studies are being conducted by T. F. Yen of the University of Southern California (12) and R. Knapp of the University of Oklahoma (13) on the ability of bacteria to be transported through porous media under subsurface reservoir conditions. Results have demonstrated that bacteria do move through porous media and that spores of Clostridium species appear to be readily transported in oil-saturated sandstones and are capable of germination with appropriate nutrients. Pseudomonas and Bacillus species were able to penetrate Berea sandstone cores at approximately 4 cm/day without an applied pressure gradient. Further studies at the University of Oklahoma are using bacteria to selectively plug high permeability zones thereby forcing injection waters into low permeability zones. Successful results were obtained demonstrating that bacteria were selectively transported to higher permeability zones causing the diversion of water flow to lower permeability zones. Experiments using three cores in parallel having low, medium and high permeability demonstrated that high permeability cores were plugged to a greater degree than medium permeability cores which were, in turn, plugged to a greater extent than low permeability cores. Accordingly, the selective plugging of high permeability zones within a reservoir appear experimentally feasible and represents a possible MEOR application.

B. BIOPRODUCTS AS CEOR AGENTS. The production of microbial polysaccharides and biosurfactants for application to EOR represents an area of principal R and D focus. Field testing and evaluation experience with xanthan gums has indicated the necessity for a wider spectrum of biopolymers with physical properties appropriate for EOR technology. It is of only recent development that alternative microbially-produced polysaccharides have occurred, with a limited number to date exhibiting beneficial properties. A few of these biopolymers will be summarized as to their application.

1. EMULSAN. This biopolymer is a high molecular weight (10^6), water-soluble, extracellular bioemulsifier produced by *Acinetobacter calcoaceticus* RAG-1 (14). Emulsan is a d-galactosamine-containing polyanionic polysaccharide-protein complex with acetate and long chain fatty acids bound via O-acyl and N-acyl linkages. Removal of the protein yields the carbohydrate polymer, with retention of its emulsifying activity. Several interesting properties of emulsan have been described:

- i) the polymer functions optimally in the presence of a mixture of aliphatic and cyclic or aromatic hydrocarbons;
- ii) emulsan enhances the formation of oil-in-water emulsions as well as stabilizing preformed emulsions at weight ratios of oil to emulsan up to 800:1;
- iii) emulsan concentration at the oil-water interface is independent of pH.

Emulsan has been demonstrated as being particularly effective in the formation of oil-in-water emulsions, removing heavy oil accumulations in storage tanks and oil tankers. Additional applications of emulsan appear favorable for pipelining operations and possibly down-hole injection.

2. POLYSACCHARIDE. Chinese scientists have reported on the isolation of a bacterium which produces extracellular polysaccharide when grown on crude oil or heavy liquid paraffins as the sole carbon sources (15). Yields of polysaccharide were 8 gm/liter from 12% (w/v) crude oil and 12 gm/liter from 4% (w/v) paraffins. The physical properties of this polysaccharide are similar to xanthan and considerably better than polyacrylamide or carboxymethylcellulose. This polysaccharide was evaluated in a polymer flood where with an injection volume corresponding to 20% of the pore volume resulted in approxi-

mately 9% enhanced oil recovery relative to the initial oil reserve.

3. BIOSURFACTANTS. a) Finnerty and M. Singer at the University of Georgia have isolated a bacterium that reduces the viscosity of heavy crude oils (API$^{\circ}$ gravity 8-10) by 95% (16). The significant viscosity change is the result of extracellular biosurfactant production by this microorganism growing at the expense of various crude oils and paraffins. The biosurfactant has been isolated and characterized as a glycolipid exhibiting a critical micelle concentration value of 1.5 mg/ml with a corresponding minimum interfacial tension of 2.5 X 10^{-2} dynes/cm. The addition of a coagent alcohol to an aqueous solution of this glycolipid at its CMC yields interfacial tension values of 6 X 10^{-5} dynes/cm. Stable oil-in-water emulsions are formed by either the growth of the microorganism on crude oil or addition of biosurfactant to crude oil. Core displacement studies with this biosurfactant have yet to be initiated.

b) Knapp and associates at the University of Oklahoma have isolated a biosurfactant which emulsifies as well as mobilizes residual oil in a sand pack column (13). Surfactant is produced by growth of the bacterial isolate on sucrose in the presence or absence of crude oil. Surface tensions of the surfactant when measured in whole broth are 27 dynes/cm with interfacial tensions less than 1 dyne/cm.

c) Extensive studies on biosurfactant production by microorganisms have been reported by Zajic and associates. Many of these studies have concerned the release of oil from tar sands. Biosurfactants have been employed in enhancing bitumen recovery by a cold water extraction process with favorable comparison to synthetic surfactants (17). Interestingly, cost-estimates for these biosurfactants were placed at 30% of synthetic surfactants with a significantly decreased toxicity factor.

CONCLUSIONS

Microbial enhanced oil recovery can be characterized as a potential technological innovation which lacks an in-depth basic and an applied data-base. Whether this critical data-base develops, depends upon a complex array of factors ranging from cost-effectiveness to socio-political considerations. Current evidences as well as experiences strongly indicate a real potential for the application of selected aspects of MEOR. Realistic assessment of the time table necessary for application of MEOR principles is mid- to long-term ventures. The most promising possibilities in MEOR are the use of microbially-produced products as CEOR agents with biopolymers and biosurfactants being preimminent as useful and utilitarian chemicals for EOR. The use of bioproducts as CEOR agents is further strengthened by our ability to specifically tailor microbial processes through physiological and genetic techniques to generate changes in:

1. oil through:
   a) reduction of interfacial tension and viscosity;
   b) conversion or directed degradation of oil constituents;
   c) alteration of oil to useful secondary metabolites or gas;
   d) in situ formation of CO_2, H_2, CH_4 and other useful metabolites.

2. aqueous phase through:
   a) increase viscosity of injection water with biopolymers;
   b) biological treatment of low-quality water used for reservoir injection.

3. reservoir rock through:
   a) alteration of rock permeability;
   b) _in situ_ leaching of rock.

4. oil shales through:
   a) surface pile leaching;
   b) enzymatic release of oil from solid surfaces;
   c) alteration of keragen or keragen-like materials.

The future interface between petroleum engineering and the application of biological processes appear complementary in terms of contributions that the biologist can offer to the industry.

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TODAY'S INDUSTRIAL COAL MARKET AND ITS CONSTRAINTS

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Two years ago, the industrial coal market was perceived by many energy forecasters as the fastest growing domestic market sector for steam coal. Today, it appears that this earlier euphoria obscured some significant constraints on the widespread use of coal by American industry. In the course of the next 20 minutes, I propose to provide you, first, with a brief overview of industrial energy and industrial coal markets derived both from publicly-available data and from a large proprietary industrial energy database developed in 1982 by Temple, Barker & Sloane; and second, with a short summary of the constraints that will impede future increases in industrial steam coal consumption.

In the course of this, I hope, three things will become apparent: (1) that there will be in the course of the 1980s a respectable increase in industrial coal consumption; (2) that clean air legislation and rail rates are not necessarily serious impediments to the increase use of coal by industry; (3) the coal industry has an important active role to play in the development of this market.

In the years from 1960 to 1980, industrial energy consumption in the U.S. increased at an annual rate of 2.0 percent, somewhat more slowly than the rate of total energy consumption (2.8 percent). In 1960, 60 percent of total industrial energy consumption was confined to three census regions: East North Central (23.6 percent), West South Central (20.9 percent) and Middle Atlantic (15.5 percent); in 1980, 57 percent of industrial energy consumption occurred in the three census regions: West South Central (26.0 percent), East North Central (19.5 percent), and South Atlantic (11.9 percent). The growth in industrial energy demand during these two decades significantly exceeded the national mean of 2.0 percent per year in four census regions: South Atlantic, West South Central, West and Pacific.

Industrial energy consumption in every region was a smaller percent of total energy consumption in 1980 than had been the case in 1960. This is a reflection of the significant conservation efforts made by industry since the rise in energy prices that began in 1973 and of the gradual structural shift of the national economy from heavy industry to a service and light-manufacturing orientation.

While total industrial energy consumption increased, industrial coal consumption declined. As recently as 1968, 91 million tons of steam coal were used for fuel and power; by 1976 this had declined to 52 million tons. The decline was concentrated primarily in three regions: East North Central, South Atlantic, and Middle Atlantic.

By 1981, industrial coal consumption had, according to the EIA, risen to 67 million tons. The real figure is most likely over 70 million. The last statement requires a brief explanation. Up to this point, my remarks have been based upon data published by the Bureau of Mines and in more recent years, by the Energy Information Agency. There are significant definitional problems with the figures published in the earlier years in these reports and the more recent efforts of the EIA have not resolved all of these.

TBS first became aware of the full extent of these statistical deficiencies through work with the 1981 EIA Form 6 data which are used to produce the official published aggregates relied upon in the survey given above. Early in 1982, Temple, Barker & Sloane undertook the building of the largest site-specific industrial energy database ever compiled in the United States. This effort involved executive interviews with the 8,000 most energy intensive facilities in the country. The result was a database of some 1,800 current coal burning facilities and proposed new or converting coal-fired facilities. For each such facility, the information in the database includes the following: the name of the company, the plant location, the four-digit SIC code, 1981 fuel consumption, primary and alternate fuel capabilities, the size, type and manufacturer of each individual combustor, the full coal specifications of the coal used, coal transportation and storage information, preferences as to suppliers and types of contracts and environmental data. This is the largest proprietary industrial fuel use database in the United States and is significantly more comprehensive than the federally-funded Major Fuel Burning Installations survey of 1975. Currently, more than a dozen coal companies are utilizing all or part of this database to assist in their marketing efforts.

A comparison of the TBS 1982 Industrial Steam Coal Database with the EIA Form 6 information indicates major omissions in the latter in two areas: (1) there are several hundred more coal-consuming facilities in the U.S. than the EIA is aware (the omissions are not confined to any one geographic region, nor are they necessarily only small coal users); (2) coal consumption in the mineral extraction industry (at least one facility burning 500,000 tons of coal per year) and in agriculture (e.g., greenhouses consuming up to 5,000 tons per year) appears to be largely omitted.

Now, to return to our overview of industrial energy consumption. Coal's share of the industrial energy market declined significantly between 1960 and 1978. A combination of the historic government data with the information derived from the 1982 TBS survey reveals the following trends:

- Natural gas gained market share at the expense of all other fuels from 1960 to 1974; subsequently, its relative share has dropped.

- The rapid decline of coal until 1976 is the consequence of boiler and kiln conversions to natural gas and oil.

- In those industrial facilities and sectors where steam coal usage has ceased or declined since 1960, it has been replaced by natural gas as the primary fuel and distillate or residual oil as the secondary fuel.

- In the short run, shortages of natural gas or increased natural gas prices have resulted primarily in increased residual oil or distillate use and only secondarily in coal conversions.

Finally, to conclude this overview, a look into the future with the assistance of the TBS database. Industrial steam coal demand as the consequence of conversions and of new plant construction is most likely to increase to 95 million tons by 1993. This increase will primarily occur in the states of the South and Southwest and to a lesser degree, of the Pacific Northwest. Coal conversion and new coal-fired plant construction will occur primarily in a relatively small number of industries (SIC code in parentheses):

--Wet corn milling (2046)
--Beet sugar refining (2063)
--Soybean oil mills (2075)
--Malt beverages (2082)
--Cigarettes (2111)
--Cotton weaving mills (2211)
--Synthetics weaving mills (2221)
--Cotton finishing plants (2261)
--Paper mills (2621)
--Paperboard mills (2631)
--Alkalies and chlorine chemicals (2812)
--Industrial inorganic chemicals (2819)
--Plastics and resins (2821)
--Noncellulosic organic fibers (2824)
--Industrial organic chemicals (2869)
--Chemical preparations (2899)
--Cement (3241)
--Lime (3274)
--Primary copper (3331)
--Farm machinery (3523)
--Construction machinery (3531)
--Motor vehicles (3711)
--Motor vehicle parts (3714)

In all cases, the conversion to coal will be a gradual, slow process. For example, much has been made of the future potential for steam coal consumption in the cement industry. The TBS database reveals that only 3 of about 150 cement plants in the U.S. had not converted to coal by 1982; incremental coal consumption due to additional conversions will be minimal. In addition, petroleum coke is making deep inroads into this market while new coal-fired capacity being built tends to be more than 50 percent more energy efficient than older coal-fired plants. In other words, despite the expectations of many coal industry forecasters, cement is not a big growth market.

With this contextual background, we can turn to examine some of the constraints, real and illusionary, on coal conversion.

First, coal is a dirty, solid fuel. TBS sampled attitudes toward coal conversion by plant managers and fuel engineers at facilities that either were converting to coal or had rejected the idea after a feasibility study. Prejudice and outright ignorance prevailed in those regions where no institutional memory of coal use remained or ever existed. California is most notable in this instance. Some of those interviewed went so far as to suggest that it was impossible to burn coal in the state (some 2 million tons of industrial steam coal were burned in 1982)! This suggests that in those states such as Indiana, Illinois, Ohio and Pennsylvania where the majority of current non-coal burning plants burned coal up to the 1950-1970 period, there would be less institutional opposition to reconversion.

Second, federal and state regulation of air pollution. As a constraint this is more apparent than real. Based on in-depth interviews conducted during the TBS survey, it would appear that companies frequently cite the Clean Air Act as an excuse for not converting to coal when, in fact, the real reason for their negative decision was that the economics of the conversion were questionable. Widespread ignorance about the implications of relevant federal and state clean air regulations for an individual plant was found in the course of our survey. This tends to be more frequently true of smaller firms than of Fortune 500 companies that have specialists to cope with these issues.

In general, current air pollution legislation permits most industrial facilities to burn coal. Likely changes in the Clean Air Act will ease the procedural if not the substantive burdens on facilities seeking to burn coal. What is needed is education and assistance for those who want to convert, not an easing of existing standards. The TBS survey revealed that while coal consumption declined in states (Illinois and Indiana) where industrial plants could emit 6.0 lbs. of sulfur dioxide/million Btu of heat input per hour, it increased in states where the standard was 1.2 lbs/million Btu or less (e.g., Florida, North Carolina, Georgia).

Third, rail rates are too high. While this may be a legitimate complaint for some utilities that can only receive coal by unit trains, it is not an insurmountable impediment for industrial users. The TBS database reveals that, in general, industrial facilities are not hostages to the railroad for coal deliveries. There is a surprising amount of competition out there and in many cases the alternative to rail delivery can be quite innovative.

We found many instances of direct truck delivery from the mine over distances up to 200 miles. Truck delivery from a barge terminal on the Ohio-Mississippi River system is common. In northern Michigan and Wisconsin, a single company, C. Reiss Coal, dominates the market through truck deliveries from stockpiles supplied by lake boats. In New England, ocean barge-truck delivery combinations are competing very effectively against direct rail delivery. In the Pacific Northwest, paper mills converting to coal are finding that barging coal in from Canada is an attractive alternative to receiving it by rail from Utah or Wyoming.

Thus, the three most frequently cited constraints on future industrial coal use are not as formidable as they are often made to appear. There are, however, three other constraints to a rapid increase in industrial coal consumption in the course of the next decade. These are, in many respects, more fundamental and there is, unlike the previous three, little that can be done by coal companies to counteract them.

First, there is the permanent erosion of the American industrial base. This is reflected in the changing geographic pattern of energy consumption that I noted earlier. Many of the industries listed above as major actual or potential coal users are in severe financial trouble. The TBS survey revealed that scores of coal-fired plants in the Midwest in the automobile, chemical, and rubber industries have been permanently closed. These heavy industries are in decline in the entire industrialized world and even a return to overall economic prosperity is not likely to restore the situation to the pre-1973 condition. The manufacture of electronic components, computers and telecommunications equipment--the growth industries of the 1980s--is not energy intensive and will not require steam coal as a fuel. In other words, the overall shift away from heavy industry in this country will be a significant drag on increased industrial coal consumption.

Second, there is conservation. This may seem to be a curious thing to cite as a constraint on industrial coal consumption but it is real nonetheless. The installation of energy management systems or other energy conservation hardware, in general, has significantly shorter paybacks and much lower capital costs than a fuel conversion. In an environment in which energy prices are showing signs of stabilizing, this method of achieving lower energy costs tends to be far more attractive than the fuel conversion alternative. This is particularly true since energy management systems are priced far below the $3-5 million cost for a fuel conversion at a moderate-sized plant.

Third, there are for most companies in the 1980s, more attractive capital spending opportunities than fuel conversion. The 1970s were an era of widely fluctuating prices for almost all raw materials. In that atmosphere of shortages and apparently ever escalating prices, the conversion to coal made sense to many company executives attempting to lower the costs of their raw material inputs. Substitution was the order of the day.

The 1980s are the era of productivity. Acutely aware of the declining competitiveness of its products in domestic and international markets, American industry will place priority on capital investments which improve productivity. In other words, the factory of the future will be filled with robots, programmable controllers, and process control computers but managers will be somewhat indifferent as to the fuel which goes into its boilers. The current payback period for most factory automation equipment averages about 2.5 years; for a conversion to coal the payback period in most instances is 3 to 4 years. The former is getting shorter, the latter is getting longer. In an environment where capital is in short supply and productivity is the yardstick by which performance is judged, it is not hard to understand how consideration of conversion to a less expensive fuel might not be a high priority item.

These three constraints will be present throughout the 1980s and unlike the first three--rail rates, air pollution regulations, and prejudice--there is little that can be done to counteract their effect.

Now, for the good news. In the near term, industrial coal consumption should increase. As capacity utilization improves together with the economic recovery, the economics of coal conversion will tend to improve dramatically. As a consequence, many conversion projects put on hold when the recession began should proceed. The decline in interest rates will also be a positive factor in this regard.

The second positive factor is the change that is occurring in the coal industry itself. An increasing number of the companies are taking marketing and market research seriously. This is an area where genuine progress can be made. Companies have tended not to concern themselves with such concepts as marketing productivity or market strategy. The traditional emphasis has been on the production of coal rather than on the efficient identification of existing or potential users. Coal companies can themselves, to some extent, determine how fast industrial coal use will grow and how large their market share will be. As was pointed out above, at least three of the constraints to increased industrial coal use, fear of high rail rates, air quality standards and prejudice, can be overcome with effort, patience and innovation.

Coal companies should assist potential customers in understanding federal new source performance standards (NSPS); in understanding the requirements for new source review (either the best available control technology, BACT, in clean air regions; or the lowest achievable emission rate, LAER, in dirty air regions); in understanding state permitting requirements for facilities that are small enough that they need not meet applicable NSPS, BACT, or LAER requirements; and in understanding the requirements concerning national or state ambient air quality standards.

A second area where coal companies can be of assistance is in financial analysis. Many firms do not fully understand the economic or financial impact of burning coal, particularly the sensitivity of the financial calculations to such critical variables as capacity utilization rates, capital costs, and interest charges. The coal producers that have been the most successful in penetrating the industrial market provide assistance to potential customers in calculating the payback (or net present value or internal rate of return) from burning coal for a variety of possible boiler and pollution control configurations.

Finally, coal companies should look into the establishment of secondary distribution terminals and delivery systems. Selecting the appropriate location for a terminal may depend on signing contracts with a sufficient number of industrial customers in an area; in turn, many customers might not sign contracts unless they are assured that there will, in fact, be a secondary distribution system. One way to avoid this situation is to use another company's existing distribution system. For example, Westmoreland Coal is utilizing Sprague Energy's barge terminals and fuel oil distribution system to market and deliver coal in New England.

There is a role in this sort of missionary activity for others apart from the individual coal companies: industry trade associations, boiler manufacturers and the railroads could all contribute to this educational process. To a very significant degree, the future growth of the industrial coal market is in our own hands.

INDUSTRIAL COAL TRANSPORTATION FUTURE AVAILABILITY & LIMITATIONS

J. R. Brian French
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I am very pleased to be able to come here today and speak with you about railroad coal transportation for the industrial user. First let me say that I am Regional Sales Manager for the Chessie System Railroads out of Detroit, Michigan. For those of you not too familiar with railroads, the Chessie System Railroads are the nation's largest transporter of coal and is made up of the Baltimore & Ohio Railroad, the Chesapeake & Ohio Railways and the Western Maryland Railroad. The Chessie Lines are, in turn, partners with the Seaboard System Railroad in CSX Corporation, a new company with immense interests and activities of its own in American coal. The CSX railroads constitute a 27,000-mile system reaching twenty-two states in the East, South and Midwest that moves more than a full quarter of the coal industry's output.

I believe these facts make us a good representative for speaking to the coal transportation needs of industry. As everybody here knows, King Coal was starting to be quite neglected during the 1960's when nearly everybody was turning to cheap oil. This switch to oil continued until the oil embargo in 1973 and the tremendous run-up in its price. Suddenly, utilities and industries rediscovered coal as a primary fuel source. To date, the electric utilities have led the charge back to coal by converting many of their oil units back to coal and by planning to build only coal units in the forseeable future. Industry, on the other hand, has moved more cautiously towards coal, presumably due to the large capital investment required to convert or to buy a new boiler. Industries are nonetheless steadily moving towards coal for their energy needs, and a cooperative effort on the part of the coal industry, boiler manufacturers and coal transporters is necessary to see that our industrial economy is once again fueled by an economical and dependable source of energy.

Let me relate to you now what railroads are doing to reach this goal. First, the railroads have a tremendous infrastructure for coal movements in place and in good working condition ready to serve its many customers. This infrastructure would not be in good shape without the large scale capital investments we have made in anticipation of an expanding coal market. The Chessie Lines alone own some 70,000 coal hopper cars, which are powered by a fleet of 2,000 diesel locomotives. That physical strength is continually improved and enlarged, and in 1983 Chessie has earmarked $340 million in capital expenditures for even more equipment, including motive power and cars to maintain our coal-transport capability. We also have our own modern coal car building plant in Kentucky that is capable of turning out up to thirty-two 100-ton coal hopper cars a day.

Chessie's efforts in behalf of its partners in coal is magnified on an industry-wide basis. As evidence that coal is far and away the most important commodity for the railroad industry, consider that in the record year of 1981, when coal production grew by half, railroads moved some 70 percent of that output to market. That transportation job for a single commodity generated more than 35 percent of all railroad originated tonnage and more than a fifth of all railroad revenue. And to present some idea of the size of the railroad investment in equipment and facilities for coal, consider also that as 1982 ended, the industry counted a surplus of 70,000 coal cars and more than 5,000 locomotives. That's easily enough to accommodate several years of coal growth without any new purchases. This is certainly an encouraging picture presented by the close partnership of coal and the railroads and the extraordinary lengths to which my industry has gone — and is willing to continue — to assure good transportation of coal.

I would like to specifically talk about the railroads' view toward the industrial users of coal. Our view is very simple, we want your business badly and we are willing to make great efforts to gain it. As you all know, the transportation industry as a whole has gone through quite a transformation of late which has left us with much greater freedoms in how we manage and operate our business. The railroad industry in particular has seen welcome changes occur through the implementation of the Stagger's Act. Railroads have suddenly been faced with the need for a strong marketing oriented approach to their business because of the newly granted competitive freedom. Railroads for many years were unable to set rates because that freedom was being closely circumscribed by regulatory law. Then came the Stagger's Act and with it a measure of deregulation that allows us to compete for business on a more equitable basis. Nevertheless, some railroad users are complaining that railroads are abusing the pricing freedom conferred by the Stagger's Act. To the contrary, it is a documented fact that the Stagger's Act is being interpreted and implemented as a way to reduce, rather than raise, rates for railroad transportation. For instance, in the coal area alone, with the freedom to negotiate long-term contracts, Chessie currently has concluded thirty-two transportation contracts and we are presently working out another thirty-eight contracts.

These contracts all reduce Chessie rates by various amounts in return for which Chessie is assured that it will earn a larger share of traffic. As a result, we are now moving substantial volume of coal business at rates lower than those in force prior to the Stagger's Act.

These contracts, both signed and under negotiation, are with customers that receive from under 50,000 tons of coal annually to over three million tons annually. We are willing to negotiate contracts with customers regardless of size and some of our more innovative and successful contracts have been with our smaller customers.

A good example of this is a contract we are currently negotiating with several small industries that have grouped together in order to gain economies of scale. In this contract, the old concept of a central disturbution facility is being employed. A location was chosen that is nearly equidistant to all the customers involved and where the Chessie System Railroads have access. The idea is to move all the coal up from the mine fields via rail, unload it onto a storage area and then distribute the coal by truck to its final destination. In this way small industries, regardless of whether or not they have rail service, are able to utilize the inherent efficiencies of the railroads. As I said earlier, we are willing to try any ideas or concepts that might increase our market share to the benefit of all involved. In this particular case, we have even teamed up with a longtime competitor, the trucking industry, to make this an economically viable operation. In this new highly competitive environment, there are no holds barred; we want the traffic and we are going to fight for it.

Our sister company, the Seaboard System Railroad, recently made sweeping rate reductions for single car shippers to many locations in the northern Midwest and in the Southeast. This action was taken on a purely competitive basis and will no doubt benefit the small shipper greatly.

The mention of Chessie's sister company, the Seaboard System Railroad, brings to mind another change occurring in the railroad industry. More and more railroads have been merging in the recent past to provide single-system service over large geographic areas. These mergers have a synergistic effect in that they allow the railroads to consolidate many of their operations which results in improved efficiency. The greater efficiencies and the savings produced by them are then passed on to the customer in the form of lower rates and improved service. In the eastern United States, you recently witnessed the merger of the Chessie and Seaboard Railroads into the CSX Corporation and more recently the Norfolk Western and Southern Railroads into the Norfolk Southern. These two mergers have produced two rail systems that overlap nearly everywhere. To say there is competition between the two is putting it mildly, and this competition will once again benefit the shipper and even the railroads in that they are forced to become better managed and more efficient.

As you probably gathered by now, the driving force that will benefit the small industries the most is the same force that made this company what it is today, competition. Competition forces us to be more efficient and more responsive to all our markets and customers. Contracts indeed play a key role in this competitive environment by allowing us to tailor our services to specific customer needs. Whereas in the past many smaller industries shied away from rail service due to demurrage and scheduling problems, we are now able to sit down on an individual customer basis and hammer out any difficulties a particular customer may have in these areas. I am not saying that demurrage and scheduling problems will be completely eliminated, but we are now much more responsive to these problems and will continue to work towards solving them.

And with regard to service, let me state that railroads are still by law common carriers. This means that we have to be fair to all of our customers regardless of size.

Chessie System Railroads also offer other services to customers that may not be familiar with coal as an energy source. Many smaller industries have been burning oil for their entire lives and others may not have used coal for 20 years or more. This unfamiliarity can breed apprehension that is unnecessary. In some cases, the expense to convert may be too great to justify; however, in many cases a switch to coal will benefit the industry greatly in terms of lower energy costs which have today become a major expense for most industries.

Once it is decided that a switch to coal is the right action, our Coal Develoment Department, located down in the mine fields of West Virginia, can assist you in locating the specific type coal that is best suited for your particular coal burning equipment. Although many people still believe that if its black and burns, it is good, this is not true. With the sophisticated coal burning equipment that is being manufactured today, coal specifications are becoming ever more important.

In summary, I would like to restate that we in the railroad industry are presently undergoing dramatic changes in the way we do business and most of these changes can be attributed to the newly highly competitive environment in which we now find ourselves. I believe you will find railroads to be much more responsive to your individual needs and problems and you will also notice a much more aggressive nature in our marketing activities. We are willing to entertain any ideas that might benefit us all through improved transportation operations. So if any of you burning coal now or considering burning coal in the future have any problems, or even better, innovative ideas of how things can be done better, please contact us and we assure you that we will be more than willing to sit down with you and work together towards the benefit of all involved.

FUTURE IN INDUSTRIAL COAL COMBUSTON EQUIPMENT

Russell N. Mosher
American Boiler Manufacturers Association

The industrial sector is a potential opportunity for the increased use of this country's most abundant fuel, coal! Surveys have shown that the industrial sector utilizes approximately 34% of total national energy. Most of this energy, to date, has been supplied by oil or gas.

Steam is the primary motive force in many industrial operations. In these industries, steam is produced by industrial boilers which are generally defined as a boiler which produces steam or hot water primarily for process applications for industrial use with incidental use for heating. They cover a wide range of sizes, capacities, pressures and temperatures. Some are also supplied for more than one application such as cogeneration.

Over the last 25-30 years, the vast majority of installed industrial boilers were designed for gas and/or oil firing. During this period, a large number of existing boilers installed as coal fired units were converted to gas and/or oil firing. Some were completely converted, that is the stoker system removed, while others had the stoker grate left intact and covered over with protective tile.

In the past 7 years, there has been renewed interest in burning coal. This has been caused by the increased cost of imported oil, government regulations and uncertainty of supply of oil and natural gas fuels.

The importance of these issues is magnified when one begins to think about the possibility of purchasing and installing a new boiler. A primary concern to the boiler designer is the fuel to be burned. It is necessary to know not only the general description of the fuel (i.e. gas, oil, coal, wood) but also the total analysis of it. Coals are not all alike but vary from mine to mine, and as far as that goes, from seam to seam in a mine.

Coal burning differs from burning natural gas or oil because it is a solid fuel. It also contains ash along with its burning constituents. When burning coal in a furnace, the inert portion generally determines how the boiler is to be designed. Coal is not a processed fuel as petroleum or natural gas fuels are, although in some cases, there is fuel cleaning at the mine or some other site. However, the inert properties remain and are removed later as ash after combustion is complete.

Because natural gas and oil burns more rapidly than coal, less volume in the combustion chamber (boiler-furnace) is required. To avoid excessive ash accumulations on furnace walls and to avoid objectionable slagging of this ash, coal fired boilers must have larger furnaces than those for oil or gas. Additionally, convection sections and auxiliary equipment used in the system must be designed to offset the tendency for fouling. Gas velocities must be slower to prevent excessive erosion of the tube surface due to ash particles entrained in the flue gas.

As mentioned, boiler design is fuel specific. Lets look at generally available types of coal fuels -

Anthracite is a hard coal with a high percentage of fixed carbon and a low percentage of volatile matter. The fixed carbon is the carbonaceous residue minus the ash that remains after the volatile matter has burned off. The volatile matter is the portion that burns off as a vapor or gas.

Bituminous coal contains less fixed carbon and tends to have greater volatile matter. Heating values range from 11,000 Btu/lb. to approximately 14,000 Btu/lb.

Sub-bituminous coals are lower heating value grades of coal which are high in moisture content, generally from 15 to 30%. They range in heating value from 8,300 Btu/lb. to approximately 10,500 Btu/lb.

Lignite is a low grade coal which is high in volatile matter as well as moisture. Heating values range from 5,000 Btu/lb. to 8,500 Btu/lb. depending upon the part of the country the deposits are located.

A fuel not actually classified as a coal is peat. This fuel is an accumulation of compacted and partially devolatized vegetable matter with high moisture content. It is considered to be an early stage of coal formation.

There are two developments in coal transportation technologies being utilized or considered today. One is the use of coal-oil mixtures (COM) and the other is coal-water mixtures or slurries (CWM or CWS). These techniques contribute toward solving some of the problems of storage, handling and distribution of bulk coal. One consideration holds that both COM & CWS enhance conversions and reconversions for the combustion of coal in boilers that were originally designed to burn gas or oil.

COM is a mixture of ground or pulverized coal and oil, typically up to approximately 50% by weight of coal.

Actually, COM is not a new technology, that is the mixing of coal and oil together. Although not commercially utilized, this application can be traced back as far as the late 1800's. Tests were initiated in Britain and later in the United States and Japan, but for one reason or another, they were dropped. The reasons for its development, which brought about the testing programs were very much like the concerns of today - the concern or possibility of oil cutbacks and shortages.

COM is a flexible fuel in that the compositions of coal and oil can be, within limits, adjusted to influence heat content, amount of sulfur, mineral matte etc. The handling and combustion characteristics are similar to that of oil rather than that of the coal.

Coal-Water Slurries are mixtures of ground or pulverized coal and water. They differ from COM in that oil is displaced entirely. Grinding of the coal is usually done in a water environment. The total water content is usually adjusted to the required balance percentages after completion of the operation. The typical physical make-up of slurries is about 70 to 80% coal and 20 to 30% water. A stabilizer is also included in the slurry to adjust it for flow characteristics and storage capabilities. Slurries enhance the transportation effort, it is easier to move fuel in that form from mine to plant site. For combustion, the slurry is fed into the furnace and the moisture or water is evaporated by utilizing some of the heat of combustion of the coal.

Now lets look at what burning this fuel does to produce the steam in a boiler. First of all lets define a boiler. A boiler is a closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof under pressure or vacuum by the application of heat.

One important way to classify boilers is according to its heat transfer configuration, i.e. firetube or watertube.

In firetube boilers, the water surrounds the furnace or some part of it as well as the tube passes. The products of combustion pass through the tubes thereby heating the water as required. In watertube boilers, the tubes contain the water and steam. The products of combustion circulate outside the tubes heating it either by radiation or convection-conduction.

An important aspect of coal firing is the selection or determination of the type of firing system. The choice of firing systems depends on the operating characteristics, efficiencies, type of coals and investment costs.

There are basically three types of coal firing systems - Pulverized, Stoker and Fluidized Bed.

The basic function of a pulverized coal system is to crush the coal, transport it to the boiler-furnace and accomplish complete combustion in the furnace as a continuous process. Raw coal is fed through a feeder to the pulverizer where it is crushed to a fine powder. From there, it is transported by a small portion of hot air, usually 15 to 20% of the total combustion air, to the burner through piping. This hot air also dries the coal in the pulverizer. The remainder of hot combustion air is directed to the windbox and to the burner as secondary air. Factors to be considered in the selection of pulverizer equipment includes:

- Variety of coals to be burned
- Moisture of the coals
- Percentage of volatile matter
- Fineness of the pulverized coal
- Range through which the boiler will operate (Turndown)

A successful stoker-fired boiler requires the proper selection of stoker for the fuel to be burned. The system must be sized to achieve the desired capacity at the optimum efficiency. Almost any coal can be burned on some type of stoker. Mechanical stokers are classified into three major types - Underfeed, Spreader and Overfeed.

In the underfeed stoker, the coal is fed from the hopper by means of a ram or screw through a central trough or retort. As the retort becomes full, the coal is pushed upwards to spread over the air admitting grates. Burning rates for underfeed stokers are directly related to the ash softening temperature. For coals with ash softening temperatures below 2400 °F, the burning rates are reduced.

Spreader stokers are designed to project coal or fuel into the furnace over the fire with a uniform spreading action, permitting suspension burning of the fine fuel. The heavier pieces fall onto the grate to be burned. This grate can be stationary or moving. Spreader-type firing action is extremely sensitive to load fluctuations as burning is almost instantaneous, therefore, changes in load can be easily followed.

Overfeed stokers are designed so that the coal in the hopper is fed directly onto the grate, whether it be continuously moving or vibrating. Adjustable entry gates are used to regulate the thickness of the fuel bed. The fuel bed burns as the grate moves along and ash drops off the far end into an ash pit or hopper.

Another currently popular technology which has been around since the late 30's is fluidized bed combustion. In this type of firing, the fuel and inert material are kept suspended and bubbling or fluidized in the lower section of the furnace through the action of air under pressure through a series of orifices in a lower distribution plate. The fluidization promotes turbulant mixing required for good combustion. This promotes the three required parameters for efficient combustion time, turbulance and temperature. This technology has been recently utilized to provide emission control for high sulfur coals. The coal is mixed in combustion with limestone which takes on freed sulfur from the coal products of combustion. This type firing also achieves a measure of NOx control in that it burns at a lower temperature, somewhat below maximum NOx formation.

The return to coal firing in boilers has brought about considerable interest to both convert and reconvert existing boilers to coal. Questions arising need to be addressed as far as plants are concerned.

Most steam plants are designed and installed on a custom basis, that is, for a specified plant cycle and a specified fuel availability. To convert, lets say, an oil fired boiler to a coal fired boiler, a complete examination and determination of the boiler and fuel-coal, must be made as to the feasibility of conversion. We discussed earlier that the coal fired unit must be designed larger than the oil or gas fired boiler. It follows then, that if the boiler is constant in size and a fuel-coal, with lower Btu content and containing ash, cannot achieve the same steam output - a derating is necessary. This sometimes is as much as 50% depending on the coal.

Other considerations to converting include space available for coal storage, bunkering of the coal, pulverizer or stoker equipment and ash removal or storage. A readily available source of coal needs to be considered. Where is it located? Environmental regulations must be checked to determine emission controls that may be required.

Recent studies have indicated that during this decade and the next, the rate of growth in coal demand is likely to be the limiting factor in national production. The long term growth in coal production will be limited by the ability to move and transport coal in an environmentally acceptable manner without undue risk to both the public and miner health and safety. Demand will be influenced by the cost of coal. This cost, in turn, will be influenced by the costs involved in land reclaimation, health and safety regulations, leasing and adequate transportation.

COAL-WATER MIXTURES: ISSUES AND OPPORTUNITIES FOR THE ELECTRIC UTILITY INDUSTRY

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Introduction

The Electric Power Research Institute (EPRI), the Department of Energy (DOE), several utilities, and various commercial interests have supported the development of coal-water slurry (CWS) as an alternative fuel for electric utility boilers. EPRI's objective has been to achieve a utility coal conversion capability encompassing current oil-fired capacity with a minimum of fuel handling or environmental control modifications. This is to provide economically attractive fuel alternatives as well as to reduce the industry's oil dependence.

Our efforts indicate that concentrated CWS has the greatest near-term potential for meeting this objective. The immediate opportunities for utility coal conversion are primarily in the oil dependent regions on the East and Gulf Coasts; particularly New England, the mid-Atlantic states, and Florida. The potential utility market in these regions alone is over one million barrels per day, oil equivalent.

These slurries typically contain 70 to 75 wt% coal pulverized to 200 mesh or finer. Minimum water content is defined primarily by viscosity considerations. The particle size distribution is such that high packing density is achieved. The slurries also contain about 1 wt% additives that impart desirable flow characteristics and storage stability. The potential advantage is that these

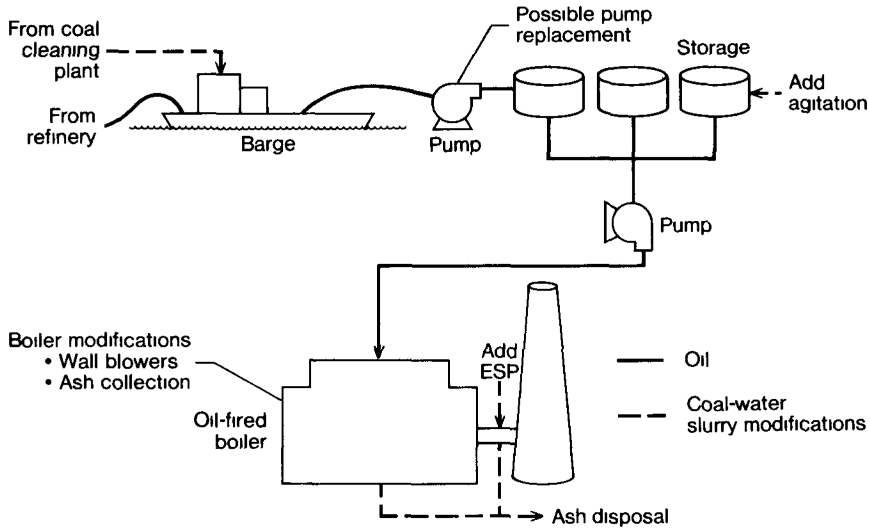

Figure 1. Coal-Water Slurry Conversion

slurries can be used in oil-design boilers with relatively limited modifications to the existing plant (Figure 1).

Previous studies with coal-oil mixture (COM; a mix of 50% coal and 50% No. 6 oil) showed that even with some modification to oil-design boilers, significant reductions in boiler load capability (derating) can be expected when they are converted to burn COM. This derating is caused both by ash content and by the different burning and heat release characteristics of coal relative to oil. The extent of this predicted derating varies with coal quality and boiler configuration (EPRI Final Report CS-2309). In order to minimize derating, the CWS studies were performed with CWS using cleaned coal with low ash content. The coal feed stock used in the initial projects was a Middle Kittaning bituminous coal cleaned to about 4 wt% ash at EPRI's Coal Cleaning Test Facility at Homer City, Pennsylvania. One of the important advantages of CWS is that intensive physical coal cleaning steps can be easily incorporated as an integral part of its preparation to minimize ash and pyritic sulfur content. The key is elimination of energy-intensive drying of the fine coal particles formed during the cleaning process.

CWS promises to cost less than No. 6 oil. The projected fuel cost for CWS, manufactured in a plant at the rate of 1 million tons per year, is about $3 to $3.5 per million Btu (1982 $). This cost includes about $1.6 per million Btu for the coal and $0.80 per million Btu for slurry preparation. Cleaning the coal down to 4 wt% ash adds another $0.50 per million Btu. The balance is for transportation of the coal by rail from the mine to a coastal slurry preparation plant and miscellaneous costs. This total cost for clean CWS of $3.5 per million Btu compares favorably with a typical current cost of $5 to $6 per million Btu for No. 6 oil.

This predicted favorable supply cost margin must, however, be carefully weighed against other user cost factors to determine the site-specific advantages of conversion. The main factors are the costs of:

- boiler and plant modifications (including installation of emission control systems),
- the loss of capacity because of decreases in boiler efficiency and derating, and
- charges for shipping CWS from the preparation plant to the user's site.

Based on the studies done to date, it is estimated that the site-specific cost to convert an oil-fired utility plant from oil to CWS will be in the range of $100 to $200/kW(e).

For a furnace designed for oil, modifications would include the addition of:

- a furnace hopper bottom,
- a furnace deslagger,
- new burners, and
- ash removal and collection equipment.

The capacity of the boiler may experience no derating for a oil-capable design to as much as 60% for box furnace configurations designed for oil. For realistic unit deratings of up to 25%, Figure 2 indicates that a differential fuel cost of between \$1.00 and \$2.00 per MBtu must be achieved to make conversion to CWS economic. Clearly the degree of derate will be a primary determinant for the practicality of conversion; however, for derated units requiring full capacity during peak periods, supplemental operation on oil can be accommodated.

Since the completion of the initial CWS feasibility studies in 1979, EPRI's projects have focused on the development of fuel specification guidelines and standardization of qualification tests, as well as on the technology required to handle and fire this fuel. Combustion tests have also been conducted in boilers of increasing capacity. A longer demonstration is planned for mid-1983 in a commercial industrial boiler. Slurry preparation processes are being developed independently by a number of companies, and EPRI has used CWS produced by several to gain understanding of the effects of a range of properties on usage behavior.

The technology has now advanced to the point where near-term commercialization is possible. Commercial utility acceptance can be accelerated by demonstration tests in utility boilers. To support tests of such significant size and duration, however, will require a much larger CWS supply capability than currently exists. Currently, a variety of interested participants is seeking to construct such a large supply capability. EPRI looks forward to working with both potential users and suppliers to rapidly achieve this capability by 1984 so that utility demonstrations can proceed as planned.

Technical Results

A. Slurry

The range of properties of CWS fuels from several vendors was tested by EPRI contractors. The range of some important properties is shown in Table 1. Extensive additional testing of physical, rheological, and combustion properties is being completed and the results will be reported in subsequent papers and reports. The data

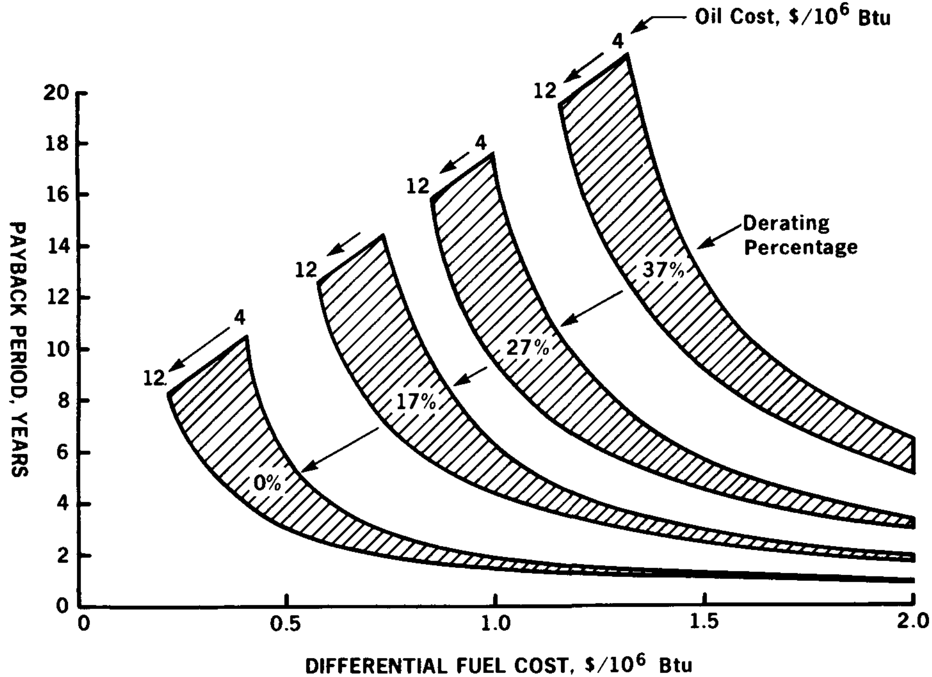

Figure 2.

rom R. Borio and M. Hargrove, ASME 83-JPCC-Pwr-42.)

obtained to date clearly show that properly processed slurries can be handled, stored, and transported using common-sense engineering. Of key importance is the ability to adjust the slurry preparation process to take into account differences in coal properties and to supply a product meeting user-specific requirements.

Table 1

RANGE OF CWS PROPERTIES TESTED
(Based on results from slurries from five vendors)

BTU (Btu/lb, dry)	13,800-14,600
Ash (%, dry)	1.7-9.2
Volatile matter (%,dry)	32.7-38.2
Sulfur (%,dry)	0.67-0.81
Solids (%)	69.3-75.3
Viscosity (c.p.)	500-1960
Storage stability - miminum settling over several weeks	

B. <u>Combustion</u>

EPRI's projects have proceeded from early tests in 1 million Btu/hr furnaces in 1980 to a demonstration in an 80 million Btu/hr test rig at Combustion Engineering's Kreisinger Development Laboratory in 1982. This test was conducted to demonstrate extended stable combustion of CWS using commercial-scale burners and fuel-handling equipment.

The coal for this test was a bituminous coal (Middle Kittaning; Hawk Mine) from Clearfield County, Pennsylvania. Three hundred tons of coal were cleaned at EPRI's Coal Cleaning Test Facilty at Homer City. Most of this cleaned coal was then used by Advanced Fuel Technology (AFT), a Gulf + Western Company, to prepare 20,000 gallons of slurry, and the balance was tested as pulverized coal for comparison. The properties of the coal as mined, as cleaned, and in the slurry (after additional cleaning by AFT) are shown in Table 2.

The slurry was shipped in tank trucks without settling from Bridgeport, New Jersey to Windsor, Connecticut, a distance of about 250 miles, and was readily discharged into holding tanks in preparation for the firing test.

Preliminary testing had been performed in Combustion Engineering laboratories and had resulted in the selection of an atomizer design and operating conditions for the test. The test was performed in a boiler at load levels from 20 to 80 million Btu/hr, although a load of 100 million Btu/hr was achieved. Other test variables were excess air level, combustion air preheat temperature, and atomization air/fuel mass ratio.

Table 2

PROXIMATE ANALYSIS OF COAL AND SLURRY FOR 80 MMBTU/HR TEST

Property	Raw (as mined)	After Cleaning at Homer City (moisture free)	In Slurry * As Received	In Slurry * Moisture Free
Moisture,%	--	--	31.0	--
Volatile matter,%	35.1	40.1	27.1	39.3
Fixed carbon,%	51.0	56.8	40.1	58.1
Total sulfur,%	1.5	0.9	0.6	0.9
Ash,%	13.9	3.1	1.8	2.6
Gross heating value, Btu/lb	13,050	14,730	10,170	14,740

*Slurry composition: 69 wt% coal, 31 wt% water, with less than 1 wt% additives.

Data on numerous independent parameters were obtained, including gaseous emissions (CO, CO_2, NO_x, SO_2, and O_2), heat flux profile, calculated combustion efficiency, flame quality, fuel-flow rate/ temperature/pressure, combustion air-flow rates/temperatures/ pressures, atomization media-flow rate/temperature/pressure, and in-stack fly ash samples were taken at selected test points. These were analysed for dust loading, carbon content, particle size distribution, and in-situ resistivity.

All tests were conducted with a tungsten-carbide-sleeved, "Y"-jet atomizer (Figure 3). After approximately 20 hours of operation, the atomizer port showed no measurable wear in the critical zones, whereas a similar carbon steel atomizer used for 4 hours showed significantly greater wear.

The CWS was ignited satisfactorily in a cold, unheated test furnace using a 5 MMBTU/hr natural-gas side pilot ignitor. The pilot flame was shut off after the slurry ignited. Nominal burner firing rate for light-off was 25 MMBTU/hr and combustion air preheat of 250°F was utilized.

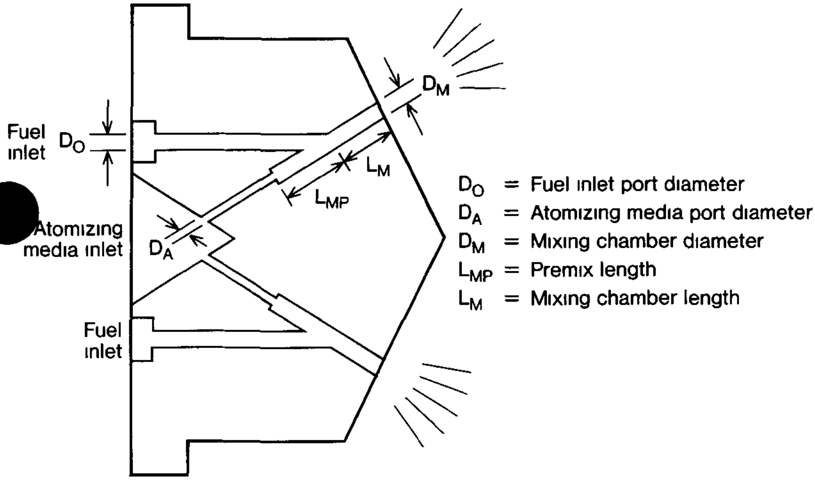

Figure 3 Critical Dimensions "Y" Jet Atomizer Design, Cross-Sectional View

In addition to this test, EPRI has underway a number of other CWS projects (Figure 4):

- Development of standards/specifications for CWS purchase (RP1985-3). Eight slurries made with different coals are being subjected to bench and combustion tests. Test standards, as well as fuel specification guidelines, are being prepared.

- Prediction of long-term utility boilers effects and conversion costs (RP1895-4).

- Demonstration of pump effects (RP1895-10). The tests which are sponsored in cooperation with Long Island Lighting, ESEERCO, and NYSERDA are being performed at Adelphi Center for Energy Studies.

- An industrial boiler test (RP1895-7). A 30-day combustion test will be conducted in an industrial boiler to assess procedures for shipment, qualification, storage, handling, and combustion of larger CWS quantities. The test is planned for April 1983.

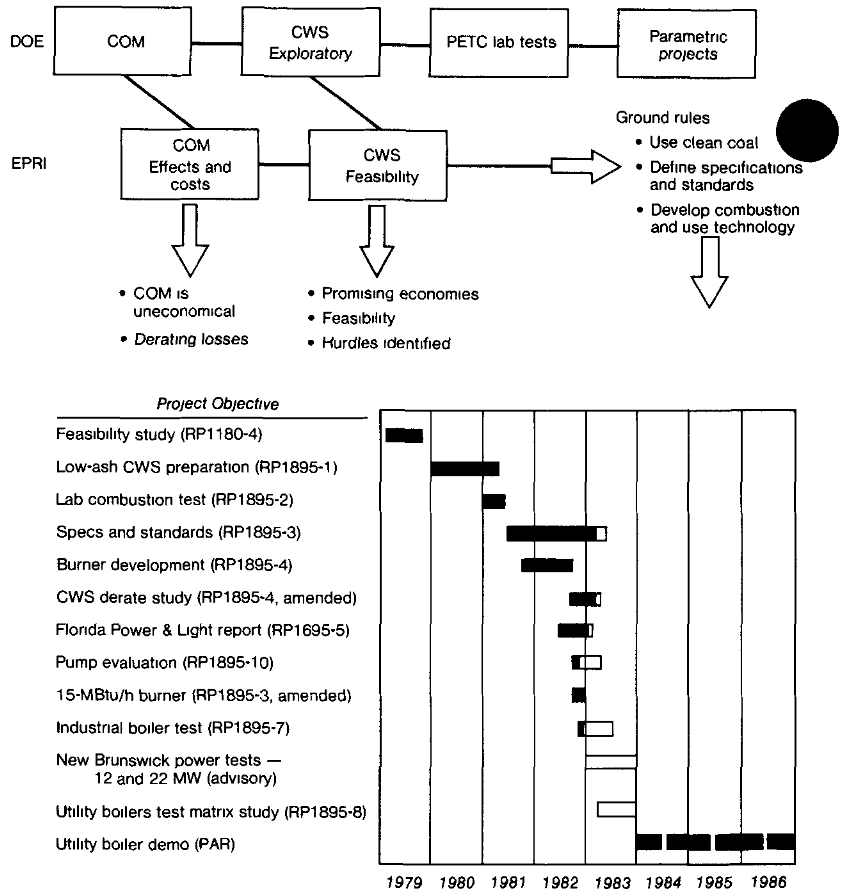

Figure 4. EPRI Program Plan

- A utility boiler test study (RP1895-8). An evaluation of six candidate utility boilers for a one-year demonstration will provide trade-off considerations and comparative costs that will serve the utilities with a decision-making tool and provide a basis for identifying favorable test sites.

- Support of utility boiler tests is planned for 1984-85 depending on the availability of an adequate CWS supply capability.

Slurry Availability

Currently, the total on-stream capacity for preparation of CWS is about 40,000 tons of slurry per year (Figure 5). More than a ten-fold increase in capacity will be needed to perform an extended demonstration in a utility boiler. The major need that is not yet resolved is the financial support for construction and operation of a CWS production line. This line must be large enough to supply at least one large boiler test at a time and must produce fuel of acceptable quality and at a predictable price.

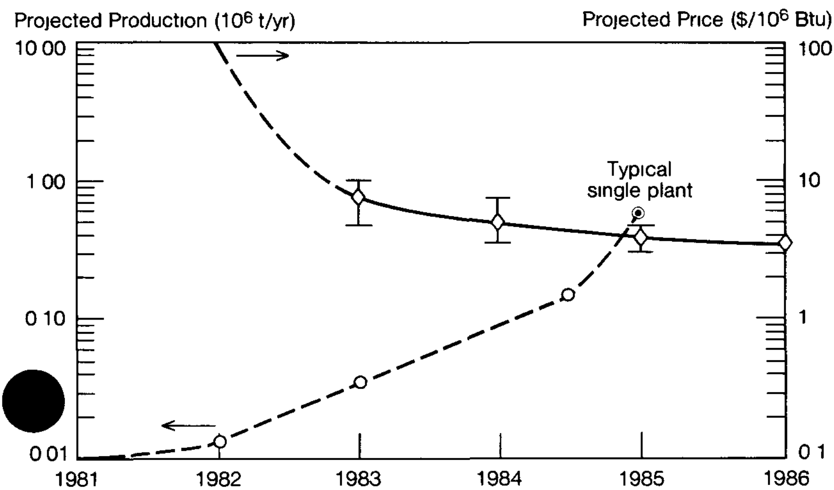

Figure 5.

A significant demonstration would consist of continuously firing CWS in an oil-design boiler of about 400 MW (e) capacity for at least six months. This magnitude test can be supported by a CWS plant producing slurry at a rate of about 500,000 tons per year. A slurry preparation plant of this size is estimated to cost about $30 million and will require 12 to 14 months to put on stream. By comparison, a fully commercial CWS facility to support a 1000 MW (e) utility powerplant will probably cost in the range of $15 to 200 million.

Such a CWS preparation plant would typically have a rail siding and a coal storage area; it would contain equipment to crush, pulverize, and clean coal, make slurry composition adjustments, store slurry, and would have access to a barge dock. It would also need a laboratory to permit adjustment of the process to coal types and for quality control.

The participants in the potential commercialization of CWS form a complex relationship (Figure 6). This relationship

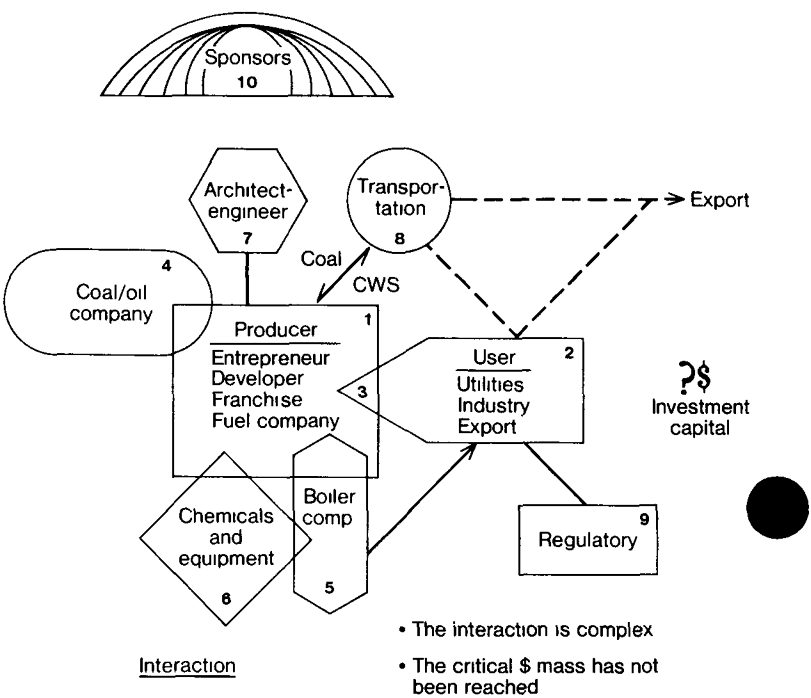

Figure 6.

includes the slurry producers (such as Atlantic Research Corp., the Advanced Fuel Technology Division of Gulf + Western, Carbogel, Slurrytech, and Occidental Research). The potential users include not only the electric utilities but also the operators of industrial boilers. Some fuel supply companies have also participated in the development of CWS.

The CWS business interactions become complex because some U.S. boiler manufacturers are now also involved as potential fuel suppliers. For example, Babcock & Wilcox (B&W) has participated in the development and demonstration of Slurrytech's fuel. Foster-Wheeler (F-W) has recently agreed to represent Carbogel (Sweden) in the United States. F-W's Forney Division has run tests on slurries and is developing burners and handling experience. Combustion Engineering (C-E) is the only major boiler company without direct involvement at this time in slurry preparation and sales. C-E has developed a burner for EPRI and is also under contract to DOE for additional slurry studies.

A number of leading architect-engineering firms are also conducting studies sponsored by utilities or with their own funding. Finally, the chemical industry and equipment companies follow this technology for the market potential in additives, grinders, pumps, valves, flow measuring devices, and burners.

Commercialization

The most likely initial commercial scenario would be the transportation of coal by unit train from Appalachian region mines to a slurry production site located on or near the mid-Atlantic seaboard. The slurry would then be transported by barge up and down the East Coast to the user's site or by tanker for export. Mine-mouth slurry preparation seems unlikely at this time because of the need for a coal-slurry pipeline.

The regulatory agencies are a very important part of the commercialization picture. The U.S. Environmental Protection Agency (EPA) stated that conversion of existing utility oil boilers to coal-oil mixture fuels would not fall under New Source Performance Standards (NSPS), but did not consider CWS. The EPA cooperated with tests of COM at Florida Power and Light Co. The regulations arising from the 1977 clean air act amendments were specific in encouraging the introduction of COM, but did not recognize the existence of CWS. There is no question that conversions of most heavy oil-fired boilers would reduce SO_2 and particulate emissions (CWS has less sulfur than most heavy fuel oils being burned, and addition of a 99.5%

efficient ESP will reduce particulate compared to uncontrolled heavy oil). Thus, with proper preparation of clean slurry, installation of an ESP may be adequate to meet standards.

Despite this positive environmental result, conversion to CWS may still be viewed as a "major modification" as defined by the very first NSPS rules. Even if the EPA decides that a CWS conversion is not a major modification, political pressure could influence the terms of the decision and its interpretation. This is a major business uncertainty for potential slurry users and suppliers that depend on conversion of oil-design boilers. Finally, EPRI, DOE, several utilities, and other companies have sponsored the technical work necessary to provide the confidence base for commercial application of this new fuel.

Conclusion

Laboratory and pilot plant tests with coal-water slurries provided by a number of vendors have confirmed the potential usefulness of CWS as a boiler fuel.

The Electric Power Research Institute has completed or has underway projects to resolve CWS technical problems and to reduce the technical risk of commercialization by;

- providing guidelines for CWS quality,
- defining the relationship between CWS properties and use requirements,
- identifying and quantifying the effects of firing CWS in oil-design boilers, and
- developing the supporting technology and demonstrating performance in boilers.

In addition to use-oriented technology projects, EPRI is studying several options to ease the problems related to construction of a slurry preparation facility. We are also prepared to cooperate with potential users and suppliers in efforts to catalyze the necessary commercial capability so that confident utility specification and use can be demonstrated by 1985. The earlier this large-scale test can be done the more quickly will any remaining problems be solved and the final technical and economic status of CWS be clarified.

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THE RESEARCH AND DEVELOPMENT PROGRAM IN COAL-WATER MIXTURE TECHNOLOGY AT THE PITTSBURGH ENERGY TECHNOLOGY CENTER

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At first glance, one could easily dismiss the notion that conventional fuels such as oil or natural gas must be backed out of the U.S. industrial and utility fuel supply mix. Myopic observers point to an apparent "oil glut," relatively soft oil prices, and an oil cartel that seems to be suffering from a conscious conservation effort that has reduced oil imports in the U.S. by an average of approximately 1.8 million barrels per day since 1980. However, Department of Energy predictions for the long term indicate that the price of oil will probably increase faster than prices of other commodities as world economic growth impacts on a finite supply of oil. Around 1987, oil prices are projected to begin increasing at a rate of 5-7% per year and continue at this rate well into the 1990's.

Furthermore, we now find ourselves in the midst of an economic recession, high interest rates and rising unemployment. This, too, has been a significant factor in the slowed growth, and indeed an actual decline in electricity demand in recent years, making new oil- or gas-fueled capacity uneconomical. However, the MITRE Corporation estimated last year that over 50% of the oil-fired electric generating capacity in this country is less than 10 years old. As a result, we find ourselves with the capability to accommodate high industrial productivity, but our economy currently restricts the private sector from capitalizing on the opportunity. Yet, there is a direct relationship between growth in electricity demand and economic growth. Fortunately, there is little disagreement within this Administration that the economy has, indeed, begun a slow recovery and that increased electricity demand and industrial growth are inevitable. Given this, it is in our long-term best interest to take more deliberate steps toward substituting abundant U.S. coal in the utility and industrial applications that are currently burning oil and natural gas.

The Department of Energy's R&D program in Alternative Fuel Mixtures began in the mid-1970's with in-house testing of coal-oil mixtures (COM) at the Pittsburgh Energy Technology Center (PETC). Since then, considerable progress has been made in the technical development of retrofitting coal-designed boilers currently burning oil to COM. Such conversions will surely have a near-term impact for displacing oil and can be accommodated with relatively little difficulty. However, modifying existing oil- and gas-designed boilers, furnaces, and process heaters to burn other coal-based alternative fuels holds promise for much greater benefits, but also poses a significant risk to the private sector.

Coal-oil mixture combustion is already considered to be a commercial technology. Utility demonstrations have been conducted at Florida Power and Light's Sanford Plant, the New England Power Service Company, and a long-term test is currently underway at the Florida Power Corporation near Tampa. However, a 1982 survey by the Electric Power Research Institute suggested that coal-oil mixtures are at best only about 15% more cost-effective than petroleum, since the cost savings in oil are not sufficient to encourage the cost of conversion and retrofit. Coal-water mixtures, on the other hand, hold much greater promise for long-term cost-savings and reduced oil demand in utility and industrial combustion applications.

These are among the considerations behind the R&D program in coal-water mixture combustion technology at the Pittsburgh Energy Technology Center. This program is designed to address the problems of converting to CWM those boilers originally designed to burn coal but are now using oil, and boilers designed for and which are now using oil and natural gas. At PETC, we have developed what we feel is a most comprehensive R&D plan that makes use of both in-house and contract research. In-house testing in PETC's Combustion Test Facility utilizes two industrial boilers to address the problem of incorporating CWM into the small industrial boiler market. Furthermore, we recently began a project management program to identify the potential for CWM in larger industrial and utility applications.

Our in-house combustion testing is oriented toward identifying suitable conditions for burning CWM in small industrial boilers designed to burn oil. The Combustion Test Facility at PETC is extremely well equipped for performing novel, unconventional testing needed to determine such conditions. We have used a 100 hp fire-tube, and a 700 hp watertube boiler, both similar to actual units found in industry. Testing began in the 100 hp unit in 1981 with a series of exploratory tests to characterize boiler performance with CWM fuel. Conversion efficiency at full load, with combustion air preheated from 300°F to 530°F, was found to range from only 81 to 85 percent and boiler efficiency ranged from 66 to 69 percent. With the experience and data gained from operation of the 100 hp boiler, we initiated scaled-up testing in the 700 hp unit. With only minor modifications to the burner assembly, we conducted a series of short-duration, full load (24,000 lbs. of steam per hour) combustion tests with a CWM containing 60 percent coal and achieved a carbon conversion efficiency of over 97 percent.

Concurrent with CWM testing in the 700 hp boiler, we began investigating the potential advantages of coal-methanol mixtures (CMM). With that, we initiated a series of tests with coal-water-methanol mixtures (CMM) in the 100 hp unit to determine boiler performance and pollutant emissions, as well as the minimum air preheat temperature required to burn these mixtures. The use of methanol as the liquid phase of a coal slurry fuel significantly increases the cost of the fuel mixture. By displacing methanol with water, the overall cost of the fuel can be reduced. In these tests, we incrementally increased the ratio of water to methanol from 0%/100% to 80%/20% while maintaining coal concentrations of 55-60% (Pittsburgh seam coal) of the total fuel composition.

Since we varied several conditions for each test, we can only interpret our results qualitatively. Nonetheless, we successfully maintained a stable flame without preheated combustion air while burning coal-water-methanol mixtures containing as much as 60% water in the liquid phase (total fuel mix was composed of 55% coal, 27% water, and 18% methanol). Carbon conversion efficiencies ranged from 86% to 92%, but we have not yet determined the relationship of efficiency to water level due to the nature of the testing method employed. It is anticipated that higher carbon conversion efficiencies will be attained when coal-water-methanol mixtures are burned in larger watertube boilers, which operate at lower heat liberation rates. Tests to confirm this are planned for later this year in the larger 700 hp boiler.

It would be presumptuous at this stage of development to say that we have clearly demonstrated the technical feasibility of coal-water mixture combustion technology in boilers designed for oil-firing. The primary reasons for this are twofold. First, as already indicated, the CWM combustion testing at PETC has been performed over short periods of time, seldom exceeding 8 hours. The conditions that we have found to be suitable must be duplicated and verified in much longer test runs to ascertain the extent of fouling, plugging, and erosion on boiler equipment. Later this year, we will be conducting tests with finely ground coal in the Combustion Test Facility to determine how this influences boiler performance and whether long-term operation can be sustained without the need for periodic ash removal. In addition to their other market uses, a number of physical beneficiation techniques under study in PETC's Coal Preparation Program may also show promise for achieving the necessary sizing and ash reduction for the fine size CWM tests.

Secondly, although our in-house testing is well-suited for developing the data needed to burn CWM in small industrial boilers, results obtained from the Combustion Test Facility must be extrapolated in order to reasonably predict performance in other practical applications. For this reason, we have included a contract research plan in PETC's Alternative Fuel Mixture Program to address the relevant questions of adapting CWM to utility and larger industrial boilers designed to burn oil or natural gas.

This R&D program is designed to investigate combustion and fuel characterization, and the performance and selection criteria of available plant equipment. By the time the program is completed in 1985, we expect to have generated enough data for the private sector to make well-informed decisions on the technical, economic and environmental feasibility of CWM as a viable alternative to conventional fuels. By coordinating a number of research activities in the private sector, PETC will first seek to establish the long-term reliability of feeding and burning CWM in oil- and gas-fired combustion equipment. The retrofit design data for such equipment and process control will then be compiled and standards for combustion, operation and equipment selection will be recommended. The economic impact of boiler retrofit and new capacity will be projected, taking into account the environmental considerations of burning a coal-based fuel in oil-designed combustion equipment.

In September 1982, we awarded approximately $9 million for two industrial teams to perform the majority of the contract research work associated with PETC's overall CWM technology program. Combustion Engineering, Incorporated, along with the Gulf Research and Development Company, will be involved in developing retrofit technology and determining the design and modification parameters of existing oil- and gas-designed boilers. In this project, Gulf will select four commercially significant coals and screen them for benefication properties. These coals will then be slurried by potentially commercial vendors, providing a total of 18 test slurries. After a number of characterization tests with these slurries, a representative cross-section of commercially available burners will be identified for combustion tests. Six commercially significant coal-water mixtures will then be selected from the 18 test slurries and burned in the best unit resulting from the burner test program in a matrix test pattern that varies fifteen individual operating conditions. Combustion Engineering will then evaluate the performance of the selected fuels in terms of erosion, corrosion, and ash deposition. Project managers will interpret this data to calculate the economic benefit of retrofitting existing equipment for CWM. Ultimately, a comprehensive data base that assembles all of this information into a useable form will be compiled and made available to industry by 1986.

The balance of the program will be assumed by TRW Inc., Babcock and Wilcox, and Stone and Webster, who will be evaluating the performance of pumps, valves, piping and the instrumentation for handling and controlling the flow of CWM through the combustion flow loop. Recently, TRW completed the design of a CWM component test facility and is currently assembling the equipment. Following shakedown, they will perform a series of short-term tests on six candidate CWM slurries from the Combustion Engineering project to identify the best slurry for a long-term test in 1985. At the conclusion of this test, all components will be analyzed for signs of erosion, corrosion and other failures resulting from CWM combustion.

Once this program has been concluded in 1985, PETC will move to mold the results of the Combustion Engineering and TRW work into comprehensive and coherent design criteria for new boiler manufacture with CWM as the intended fuel. The proposed utility demonstrations by EPRI, the overall PETC program, and other private sector activities should then be sufficient to encourage industry to accept the responsibility for demonstration and commercialization of CWM technology by the late 1980's. We feel that the use of private firms such as Combustion Engineering and TRW, with the benefit of Federal support, is the most effective way to generate the kind of knowledge that will be of the most interest to industry once the program is completed. Moreover, the data used to determine economic trade-off potential is likely to be more realistic when tabulated from an industrial perspective.

Since our project management R&D program is just getting underway, it is far too early to project any cost comparisons or economic benefits. Others, however, have weighed the advantages of retrofit to CWM against the conversion to coal-oil mixtures (COM) or solid pulverized coal in facilities originally designed to burn oil or natural gas. Precise figures vary, but the consensus is that the least costly boiler modifications are to be found in COM retrofit. However, the real benefits of CWM are realized in fuel costs, particularly when the fuel is produced in commercial quantities. For instance, Babcock and Wilcox estimated the cost of "Co-Al" (produced by Slurrytech, Inc.) CWM fuel to be approximately $3.50-3.75 per million Btu's (in 1982), a cost that is certainly competitive with both premium fuels and coal-oil mixtures.

Highly beneficiated coal is yet another key element of CWM combustion technology. The electric utility industry has expressed its belief on a number of occasions that the prospects for CWM become much more attractive when the coal is cleaned to the extent that "add-on" environmental control systems do not make conversion to CWM cost-prohibitive. To this end, PETC is endeavoring to incorporate deep beneficiation techniques that bring ash levels down to a minimum into competitive coal-water slurry preparation processes. By the time the CWM program has concluded in 1986, we should be much better able to predict the extent of oil displacement as well as the precise cost-effectiveness of using CWM in oil-designed applications. In the final analysis, the overriding consideration is the realization that CWM is the most viable option available for displacing premium fuels in utility and industrial applications in this century.

In the next three years, coal-water mixture combustion technology will approach that stage of development where the government's role should become less conspicuous. It's our sincere hope and belief that the data base generated from our R&D program by the mid-1980's will be a valuable working tool for industry. Additionally, if the Department of Energy's predictions for oil price increases are indeed realized, I believe the timing of CWM technology development will be most opportune. It is quite conceivable that by 1986 or 1987, a 5-7% per year increase in oil prices will prove to be the necessary jolt to the economy that incites industrial activity in CWM and other alternate fuels. If this is the case, we may well see the near-term benefits of coal-water mixtures in our domestic supply mix by the early 1990's.

EXPERIENCE WITH COAL-WATER MIXTURES

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Florida Power & Light Company (FPL) has approximately 12,700 MW_e installed capacity, serving some 2.4 million customers in eastern and southern Florida. Of this 12,700 MW_e, approximately 2,200 MW_e are nuclear, and the remaining 10,500 MW_e use oil and gas. In 1981 FPL burned some 40 million barrels of oil, most of it imported, which made FPL the largest oil burning utility in the United States. FPL recently reduced its projected oil consumption through an agreement to purchase 2000 MW_e of "coal by wire" power from the Southern Company. These purchases will reach full capacity in 1985, and will be reduced to zero between 1992 and 1995. This action has the double advantage of immediately reducing oil consumption and providing time to develop various fuel conversion technologies. It will also allow time for the development of alternatives to conventional pulverized coal (e.g., fluidized bed boilers or coal gasification-combined cycle units) for new generating capacity that will be needed in the nineties.

About four years ago, FPL began to look seriously at what might be done to convert some of its oil burning plants to coal, which it considers as the only alternative fossil fuel. After a review of coal gasification and liquefaction it was concluded that a pumpable mixture of coal suspended in a liquid was the most likely candidate for early application. The liquid options included residual oil, distillate, both methyl and ethyl alcohol, and water. A mixture of residual oil and coal was chosen for FPL's first demonstration because of the extensive development work that had already taken place in both the government laboratories and in private industry. This backlog of experience reduced the technological risk and provided guidance in the design of the preparation plant and the power plant modifications.

The record of FPL's experimental burning of a coal-oil mixture (COM), up to 50% coal by weight, in its Sanford Unit #4 (a 400 MW_e face-fired Foster-Wheeler designed unit) during 1980-81 is well documented elsewhere (1)(2)(3)(4)(5). It is sufficient here to summarize some of the results so that the lessons learned can be applied to the development of future coal-liquid fuels, specifically coal-water mixtures (CWM).

The COM demonstration on FPL's 400 MW_e Sanford Plant was a technological success in that the unit generated over one billion KWHr of electricity during a one-year period while operating on a coal-oil mixture ranging from 10 to 50% coal by weight. Problems that developed during the test were solved, and there is every reason to believe that it would be possible to operate indefinitely on a 42% coal by weight coal-oil mixture in which about 34% of the energy generated would come from the coal.

Perhaps the most serious problem encountered was an extensive accumulation of melted ash on the boiler walls in spite of using a non-slagging coal (over 2650°F initial deformation temperature). Atomizer wear was also a major problem which required extensive redesign to extend service life. The larger coal particles tended to settle out of the mixture in the storage tank, leaving several hundred tons of coal on the bottom of a 55,000 barrel storage tank at the end of the demonstration. This last item is attributed to inadequate or improper additives and possibly too high a temperature in the tank. There was some evidence of wear in the burner pumps, but no fireside erosion was observed on the boiler tubes. The derating of the plant was minimal when the coal content was 42% or less. The derating for higher coal concentrations was due primarily to limited fan capacity since about 17.2% excess air was required for stable combustion.

From an economical standpoint, the COM demonstration was marginal. Continued operation would have required the installation of a precipitator (estimated at about \$30-million) as well as extensive (and expensive) modification of the coal and ash handling equipment. A summary of the costs of the demonstration are given in Table 1 which indicates that about half of the total cost was recovered from fuel savings. The Florida Public Service Commission allowed FPL to recover the rest through a fuel cost adjustment. It was FPL's conclusion that many of its plants could be rapidly converted to burn a coal-oil mixture in the event that an oil supply emergency made it absolutely necessary to reduce oil consumption, but in the absence of such an emergency these conversions would not be made for economic reasons. Falling oil prices in 1981-82 made the conversion of plants to burn COM even less attractive, and FPL began to look at other alternatives.

TABLE 1. COST OF THE SANFORD COM DEMONSTRATION

			Millions of Dollars
CAPITAL:	COM Prep Plant.	$9.1	
	Modification of Power Plant	$4.6	
			$13.7
OPERATING:	COM Prep Plant.	$3.7	
	Power Plant*.	$1.0	
			$ 4.7
TOTAL COST			$18.4
FUEL SAVINGS			$ 8.2
NET COST TO CUSTOMERS.			$10.2

*Extra Costs due to COM demonstration.

Preliminary engineering studies by an architect/ engineer firm indicated that conversion of the 400 MW_e plants to pulverized coal would be quite expensive and unattractive, particularly in light of the anticipated loss of capacity associated with such a conversion. This left the new but developing coal-water mixtures as the primary candidate for future conversions. Since FPL probably has as large an incentive as any other utility to find a substitute for oil (13 of its 26 oil-fired units with a total capacity of 6800 MW_e are deemed to be potential candidates for conversion), they began an extensive study of all aspects of coal-water mixtures (and coal-oil-water mixtures to some extent).

The primary problem associated with burning coal in a power plant that was designed for residual oil is the fact that coal burns differently than oil. The amount of heat that is transferred from the burning oil to the radiative and convective surfaces of the boiler differs from those for burning coal. Pulverized coal usually ignites slower than atomized oil droplets, tends to burn longer, and the glowing, long-burning coal particles remain at a high temperature for a longer time, thereby transfering more radiative heat than oil which burns more rapidly. Hence, there is a basic incompatibility in burning coal in a power plant designed to burn oil. There are, of course, means of compensating for this difference. One of them is to grind the coal finer so that it ignites and burns faster; another is to mix coal and oil together so that the fast igniting oil accelerates the burning of the coal. This is the essence of the theory of the coal-oil mixture. With coal-water mixtures, the primary concern was how the presence of the water would influence the combustion. By mid 1981, successful small scale combustion tests had been carried out, but information on flame stability, and the influence of ash, various amounts of water, coal volatility, slagging and fouling was sketchy at best. Because of the wish to secure "first hand" experience with CWM and to evaluate independently the various coal mixtures being developed, FPL undertook several combustion tests in a small combustion test facility at Battelle Columbus Laboratories. The objective was to provide a preliminary evaluation of the suitability of several candidate coal mixtures. This testing began in the Fall of 1981 and was only recently completed. The combustor used has a water cooled, refractory lined test chamber five feet long and two feet in diameter and has a maximum rating of 1,000,000 BTU/Hr. Combustion air could be preheated to 600°F. Exit gas conditions were held constant at approximately 2200°F with a velocity of approximately 50 feet per second in a simulated superheater section. A variable swirl burner with air atomization and external mixing was used for these tests. Air cooled probes provided input to the data acquisition system. Coal mixtures tested included the Sanford COM (42% coal), one coal-oil-water (COW) mixture, and five coal-water mixtures (CWM). Coal mixtures were provided at no cost by the various companies developing them, and the results of each test were shared with the supplier of that mixture.

Below is a summary of the test results for the five CWM fuels:

1. All five CWM fuels were fired successfully and achieved the desired exit gas conditions.
2. Difficulties were encountered in achieving good atomization with all CWM fuels, indicating the need for further atomizer development.
3. CWM fuels were successfully handled in the laboratory, although there were difficulties with the presence of larger coal particles (>20 mesh) and agglomerates, formation of scum on the

surface, variation of density throughout the mixture, and settling of the coal particles.
4. Carbon conversion efficiencies of 99.0 to 99.9% were achieved.
5. CWM fuels with low ash content tended to have larger percentages of unburned carbon in the particulate control equipment.
6. Priority pollutants (SO_x and NO_x) were predictable based on fuel analyses.
7. The quantity of deposits in the test section varied over a wide range and was related to the amount of ash and its characteristics. However, the deposits did not strongly adhere to the test probes and the simulated boiler tubes.
8. There appeared to be a storage time limit with all of the CWM fuels tested.

Perhaps the most significant conclusion of the Battelle tests is that the quantity and characteristics of the ash in the coal is the most important variable in predicting fuel performance. Preliminary engineering studies indicate that FPL's nine 400 MW_e plants could probably burn a low (less than 3%) ash, high BTU (about 14,500 BTU/lb.) coal without derating, provided that volatile content and other fuel requirements were met. Furthermore, a low ash fuel reduces the cost of emission (particulate) control, ash handling, ash disposal, and minimized the probability of abrasive interactions between the combustion gases and the boiler tubes. Such a premium fuel is available by "scalping" selected coals in coal-washing plants. Unfortunately, the quantity available is probably adequate for only a few power plants because of the coal sensitive nature of this approach. Recent advances in physical cleaning may allow the use of coals with higher ash content provided that the increase cost of cleaning does not negate the lower coal cost.

Coal-water mixtures with coal contents of 75% by weight or greater have been demonstrated. Simple thermodynamic considerations indicate that the water content should be minimized, but the "water penalty" is not as severe as generally believed. It is informative to examine the characteristics of CWM fuels with various coal-water ratios. For this illustration, three CWM fuels with coal-water ratios of 65-35, 70-30, and 75-25 percent by weight were chosen using a 3% ash coal. The density and heat content of these fuels as well as the constituent materials are given in Table 2. Since some of the energy of the coal is used to evaporate the water and heat the water vapor to an average flue gas temperature, the net energy available is reduced as shown in Table 3. The water penalty ranges from about 5.5% to 3.5% for the three CWM fuels. While not negligible, such a loss of energy availability is probably acceptable

TABLE 2. CHARACTERISTICS OF CWM WITH 3% ASH COAL

	DENSITY		HEAT CONTENT	
Constituent	lb/ft^3	lb/bbl	BTU/lb	10^6BTU/bbl
Dry Coal(0% Ash)	80.0	449.2	15,000	6.738
Ash	120.0	673.8	0	0
Water	60.0	336.9	0	0
Dry Coal(3% Ash)	81.2	455.9	14,550	6.633
CWM(% by Weight)				
65-35 (3% Ash)	73.8	414.3	9,458	3.918
70-30 (3% Ash)	74.8	420.2	10,185	4.280
75-25 (3% Ash)	75.9	426.1	10,913	4.650

TABLE 3. NET AVAILABILITY OF ENERGY IN CWM

CWM(% by Weight)	BTU/lb	BTU to Evap Water*	Net Avail BTU/lb.	% BTU Avail	% Water Penalty
65-35	9,458	525	8,933	94.45	5.55
70-30	10,185	450	9,735	95.58	4.42
75-25	10,913	375	10,538	96.56	3.44

*Based on 1500 BTU/lb Water (i.e. 980 BTU/lb to evaporate the water and 520 BTU/lb to raise its temperature to the "average" flue gas temperature).

because of the expected benefits; e.g. reduced cost of fuel preparation, (i.e. reduced quantity of additives, reduced grinding cost), reduced pumping power requirements, improved fuel atomization in the burner, reduced quantity and complexity of the additives required, and improved plant response to an "upset" condition. There is, however, an increase in the quantity of CWM fuels required for a given energy output. Table 4 shows increases from 324 to 382 pounds of mixture per MW_tHr and from 31.9 to 38.7 gallons per MW_tHr as the coal loading decreases from 75% to 65%. Table 5 shows the corresponding increase in required quantities per day of CWM fuel and its constituents (coal and water) for a 400 MWe power plant with a heat rate of 10,000 BTU/KWe Hr. This means larger storage capacity, larger pumps, larger pipes, greater fuel transportation costs, high gas velocity in boilers, and greater consumptive use of water. Most of these quantities produce only "second order"

TABLE 4. QUANTITIES OF CWM FUEL REQUIRED PER MW_tHR

CWM(% by Weight)	lb/MW_tHR	gal/MW_tHR	bbl/MW_tHR
65-35	382.1	38.74	0.922
70-30	350.6	35.06	0.835
75-25	323.9	31.93	0.760

TABLE 5. QUANTITIES OF COAL WATER AND CWM REQUIRED PER DAY FOR A 400 MW_e POWER PLANT*

CWM(% by Weight	COAL Tons/Day	WATER Gal/Day	CWM bbl/Day
65-35	3,492	468,830	25,933
70-30	3,453	368,960	23,487
75-25	3,416	283,910	21,377

* Based on a plant heat rate of 10,000 BTU/KW_e Hr

increases in the fuel cost. The increased velocity of the flue gas is small because the quantity of combustion gas from the coal greatly exceeds the quantity of water vapor. Transporation costs are impacted by the larger amount of water in the CWM mixture. One scenario involving rail transportation from the mine to a CWM processing plant at an east coast site, followed by water transportation to one of FPL's plants indicated an increase in total transportation cost of $0.01 to $0.02 per million BTU's for each percent increase in water content. Consumptive use of water for the production of coal-water mixtures may or may not be a problem depending upon the local availability.

Combustion of coal-water mixtures in test burners has been demonstrated and burners specifically designed for CWM are being developed. It has been found that for flame stability and combustion efficiency, the burner must create aerodynamically staged combustion. Recent trends are towards the use of multiple zone (multiple register) burners to maximize control of the air turbulence and swirl required for optimal combustion of CWM, and to provide good flame stability and operating flexibility. Recirculation of the flame by dual region high-swirl burners increase the residence time of coal particles in the boiler, allowing more complete combustion, and prevent impingment of hot partially burned coal particles on the back wall. Turndowns of 4 to 1, carbon monoxide emissions of less than 100 PPM, and 0.10 pound of atomizing air per pound of CWM have been achieved with secondary air temperatures of 300°F to 600°F. CWM burners of 50 million BTUs per hour are presently available and scale up to the 200 million BTUs per hour size for full scale testing should be readily achieved.

The conversion of existing oil-fired power plants to CWM fuels requires a study of the trade-offs between coal-cleaning processes, CWM-slurrying processes, and power plant retrofit requirements. CWM fuel properties should be selected to minimize the overall cost of the fuel conversion, not just the power plant retrofit costs alone or the fuel production costs alone. Energy recovery and cleaning efficiency of coal-cleaning processes are very dependent on the nature of the raw coal; hence the cleaning processes, in turn, can affect downstream slurrying processes and the final CWM fuel properties. For example, residual chemicals used to bond coal particles together in froth flotation coal/ash separation can adversely affect CWM rheological and settling properties and may lead to severe problems during fuel atomization and combustion. Similarly, chemical coal cleaning processes which significantly lower the volatiles content of the source coals will not be appropriate for CWM fuels.

Producing CWM fuels involves the use of chemical surfactants and stabilizers which have sometimes been selected on the basis of rheological and stability properties alone. Such chemicals can have adverse effects on fuel atomization, combustion rates, carbon burn-out, ash deposition, erosion and corrosion. CWM fuels need to be designed for combustion and emission properties as well as for pumpability and storage stability. It is only by simultaneously considering coal cleaning, slurrying, and CWM combustion that a well-designed CWM oil-backout fuel can be developed.

While firing a CWM fuel in a boiler designed for oil-firing, proper heat balance must be maintained to avoid a derating of the unit. Major load-limiting factors are the heat extraction rates in the furnace and boiler convective sections, and permissible mass flow velocities. Experience may show that it is essential to keep furnace wall tubes absolutely clean to insure efficient heat extraction in order to maintain furnace exit temperatures within permissible design limits.Safeguards against furnace slagging, which would severely limit heat transfer, are selecting coals with high ash-fusion temperatures and achieving high carbon utilization through proper burner design and operation. Fouling, on the other hand, may be accommodated with the installation and operation of furnace wall blowers and soot blowers in the convective sections. In units having closely-spaced convective sections, it may be necessary to select a coal that has been beneficiated to a very low ash level.

There are many questions regarding the use of coal-water that can be answered only by an extensive demonstration program on a full size utility power plant. Such a program similar in scope and magnitude to the COM demonstration which FPL carried out on its Sanford Plant has been planned for 1985 by the Electric Power Research Institute (EPRI). FPL has a keen interest in this project and is discussing the situation with EPRI, the Florida regulatory bodies, power plant vendors and potential suppliers of CWM fuel. The question is not whether CWM will burn, that has been demonstrated conclusively, but whether CWM will burn efficiently and reliably under a wide range of conditions in a large furnace that was designed only for oil firing. A well instrumented, full-scale demonstration is essential to understanding the thermal and fluid behavior of combustion gases as they move through the furnace and to provide design parameters for needed plant modifications.

It is not a foregone conclusion that CWM fuels will be economical in the future. The recent fluctuations in the price of residual oil (over 35% variation within a few months) makes any conversion very risky financially. A recent study (6) shows that FPL could only pay a premium of $1.43 per million BTUs for cleaning and processing coal into a CWM fuel. While this number is preliminary and the result of many assumptions, it clearly indicates that there is little basis for using complex cleaning and processing or expensive surfactants. If, however, conventionally cleaned coal (6-8% ash) can be used in CWM fuels, and if inexpensive surfactants can be used (even if this means using lower coal loadings), then it is reasonable to expect CWM fuels to be attractive even if oil costs remain low. Regardless of current economics, CWM fuels appear to offer an attractive alternative in the event of a severe oil shortage.

In conclusion, FPL is enthusiastic about the possibility of converting some of its oil-fired power plants to coal-water mixtures. However, there is a great deal of technology that needs to be demonstrated before the apparent economic advantages can become a reality in a utility boiler.

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THE SULF-X FLUE GAS DESULFURIZATION PROCESS

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I. INTRODUCTION

The Sulf-X Process is a wet absorption process that utilizes a slurry of continuously regenerated ferrous sulfide solids to provide highly efficient scrubbing of combustion gases to remove a minimum of 90 to 98% of sulfur dioxide gases. A coal-fired sulfide-regeneration system converts collected sulfur dioxide assimilated by sulfides into salable elemental sulfur by-product with minimal formation of non-regenerable waste solids and liquids. The process is presently in small commercial scale demonstration and testing that follows from six years of laboratory, bench-scale, and prototype system testing and development. Ongoing proving of the process is strongly encouraged by the comparative simplicity of the means for production of valuable elemental sulfur by-product, the low cost of ownership and operation in comparison with other regenerative processes, and the 1980s trend toward such open-loop FGD systems brought about by commercial deployment of forced-oxidation operation in lieu of natural-oxidation mode operation in limestone scrubbing applications.

II. PROCESS DESCRIPTION

Ideally the Sulf-X Process is used after dry fly-ash collection, as well as pre-scrubbing when required for segregated low-pH absorption of tramp constituents such as hydrogen chloride. In the FGD operation, schematically illustrated in Figure 1, an aqueous slurry of iron/sulfur compounds, primarily finely divided ferrous sulfide (FeS) reagent in excess along with secondary iron and sulfur species, is used to absorb sulfur dioxide (SO_2) in a wet scrubber. By providing a chemically reducing (absorption-reduction) environment in the liquid phase, and with provision for extended gas residence time in the scrubber, a major proportion of nitrogen oxides present may also be collected. Suspended solids in the bleed from the scrubber are dewatered by thickening and centrifuging and thereafter

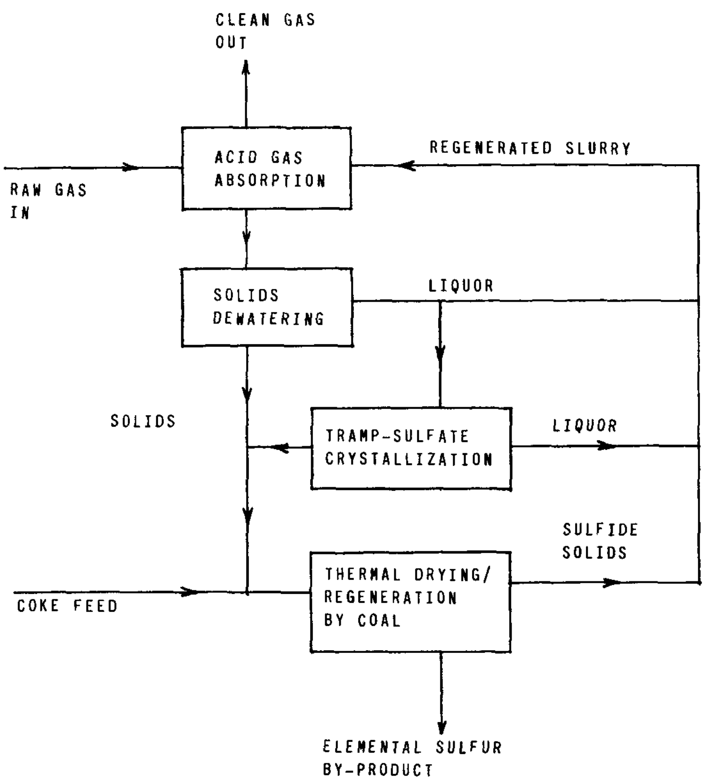

Figure 1. Sulf-X Process Flow Diagram

thermally dried and then roasted in an indirect-fired calciner using coal fuel. The thickener overflow stream, principally containing dissolved sodium sulfate (Na_2SO_4) and ferrous sulfate ($FeSO_4$), is discharged to a calciner quench tank to both cool and slurry the hot solids leaving the calciner. However, a portion of the overflow stream is diverted to a crystallizer system to form sodium sulfate solids. Net loss of sodium, if any, from the system is made up by addition of sodium sulfide. After the dewatered crystallizer product is combined with the absorber-product centrifuge cake for drying, a proportion of coke is added at the calciner inlet. In the calciner at $1400^{\circ}F$, sulfur-rich ferrous sulfide formed in the scrubber dissociates to ferrous sulfide and elemental sulfur, and the sodium sulfate is reduced to sodium sulfide. The sodium sulfide subsequently reacts with dissolved ferrous sulfate in the quench tank to precipitate ferrous sulfide. Sulfur released during the calcination leaves the calciner as a vapor and is recovered by condensation. By-product steam is generated in the sulfur condensation step as well as in an unfired waste heat boiler applied to the calciner exhaust combustion gases. The Sulf-X Process sulfate-make is crystallized and thermally reduced in the form of sodium sulfate because reduction to sulfide is thereby accomplished without liberation of SO_2 that would accompany calcining of alternative sulfate forms such as ferrous sulfate. Calcination of sodium sulfate is a common commercial process. Moreover, in the Sulf-X Process, iron compounds that are present catalyze the reduction of sodium sulfate,and the minimum temperature for its reduction is less than the design temperature for the concurrent calcination of the sulfur-rich FeS forms.

III. PRINCIPAL CHEMICAL REACTIONS

A. ABSORPTION REACTIONS, SO_2 REMOVAL ONLY: When the system is engineered at a typical FGD-process superficial gas velocity of approximately 10 feet per second, minimal NO_x removal occurs. The overall chemical reaction describing SO_2 absorption in the scrubber is complex, but may be expressed algebraically as:

$$(c)FeS+SO_2+O_2 \xrightarrow{H_2O} (c-1)FeS_{(m)} + Fe^{++} + SO_4^{=} + (1-\tfrac{n}{10})S^{0}$$

Intermediate absorption reaction products include HS^-, $SO_3^=$, HSO_3^-, and $S_2O_3^=$ (thiosulfate). Secondary reactions not reflected include oxidation of ferrous ions to ferric, and oxidation of bisulfite and sulfite ions to sulfate. The quantity "n" above,an integer that can range from 1 to 10, is a measure of the degree of sulfidation of the reagent arising from its direct reaction with elemental sulfur formed in the absorber, and reflects the spectrum of reaction products between FeS(fresh) and FeS_2(fully spent). The quantity "(c)" is greater than 1 but less than 2, its magnitude varying from application to application, and from one operating condition to another, depending on redox (reduction-oxidation) equilibrium. In commercial design, FeS is typically fed to the absorption reaction based on the design assumption that c=2 moles FeS per mole SO_2 absorbed. The quantity "(m)" equals (n/10+c-1)/(c-1). Analyses have shown that the particles of SO_2-reaction-product consist of elemental sulfur and sulfur-rich iron sulfides (FeS_m), with unreacted FeS at the core. Studies have shown that neither x-ray diffraction nor chemical analyses of these type materials are sufficiently selective to fully and accurately define the distribution of the iron/sulfur compounds formed. However, x-ray and bulk analyses have qualitatively confirmed the presence of iron sulfides and elemental sulfur, the latter having been extracted with carbon disulfide under laboratory conditions.

B. ABSORPTION REACTIONS, SIMULTANEOUS SO_2/NO_x REMOVAL: When the scrubbing is designed for catalysis by a significant concentration of ferrous ions, e.g. 40 grams/liter, and with flue-gas residence time in the scrubber sufficient to achieve appreciable NO_x removal, the overall chemical reaction mechanism becomes:

$$(c)FeS + SO_2 + NO + \tfrac{1}{2}O_2 \xrightarrow[H_2O]{Fe^{++}} (c-1)FeS_{(m)} + Fe^{++} + SO_4^{=} + (1-\tfrac{n}{10})S^o + \tfrac{1}{2}N_2\uparrow$$

Additional intermediate reaction products include $Fe(NO)^{++}$.

C. REGENERATION REACTIONS: Individual chemical reactions in the regeneration system are as follows:

$$FeS_{1+\frac{n}{10}} \xrightarrow{\Delta} FeS + \tfrac{n}{10}S^o\uparrow \qquad \text{(Calciner)}$$

$$Na_2SO_4 + 2C \xrightarrow{\Delta} Na_2S + 2CO_2\uparrow \qquad \text{(Calciner)}$$

$$Na_2S + FeSO_4 + H_2O \longrightarrow FeS\downarrow + Na_2SO_4 + H_2O \qquad \text{(Quench Tank)}$$

IV. PROCESS ADVANTAGES

Due to the simplicity of design and economy of operation, the annual revenue requirements for Sulf-X application are expected to be lower than other available methods for high-efficiency acid-gas cleanup:

Regenerable ferrous iron compounds are used as acid-gas absorbent in lieu of non-recoverable lime or limestone alkalis.

Salable sulfur is produced rather than SO_2 sludge.

Tramp sulfate-make is continuously regenerated so as to avoid need to purge any sulfate waste product. Tramp dithionate production does not occur.

Minimal iron losses are replenished through makeup by inexpensive industrial by-product iron compounds such as pyrites, (FeS_2).

Thermal regeneration utilizes coke and boiler coal-fuel, and the process requires no premium fuels or raw material derivatives thereof such as ammonia or reducing gases.

The salable sulfur yield is a direct product of the coal-fired regeneration step and thus no further chemical processing of this regenerator by-product is needed.

When designed with provision for enhanced gas-residence time in the wet scrubbers, application of the process for flue gas desulfurization provides an absorption-reduction chemical environment , and from 60 to 90% of nitrogen oxide gases are simultaneously removed and converted to innocuous elemental nitrogen (without formation of imidodisulfonate or other nitrogen/sulfur tramp ion complexes typical of EDTA-catalysed absorption-reduction processes.)

V. PROCESS DEVELOPMENT, TESTING, AND DEMONSTRATION

Development of the Sulf-X Process through laboratory and field testwork was completed in 1980. Design and construction of a stoker-boiler size integrated process installation for the Commonwealth of Pennsylvania was completed in 1982. This demonstration facility is now in operation and will be used for process scale-up in pulverized coal-fired boiler applications.

A. PRELIMINARY PROCESS STUDIES: Beginning in 1976 an intensive laboratory, field pilot-plant, and bench-scale test program was carried out to establish the present Sulf-X Process design. After earliest laboratory studies of the gas absorption characteristics and thermal regeneration of ferrous-sulfide type compounds, a pilot-plant scrubber using this Sulf-X reagent was field tested on boilers firing a diversity of bituminous coal fuels,and demonstrated SO_2 removal efficiency as high as 96% with NO_x removal levels ranging to higher than 60%. Gas absorption mechanisms were subsequently studied in the laboratory under the sponsorship of the Department of Energy (D.O.E.) to characterize the catalysis of NO_x removal by ferrous ion in the presence of suspended ferrous sulfide solids. D.O.E. commissioned an advanced bench-scale technical development program, completed in 1980, which utilized a bench-scale replica of the entire process, absorption as well as regeneration. It assessed integrated closed-loop process operation treating actual coal-fired boiler emissions containing adversely high oxygen content, e.g. ranging in excess of 10% by volume. Accompanied by SO_2 removal at the 95% level with NO_x removal above 80%, ferrous sulfide reagent successfully underwent more than 10 repetitive cycles of regeneration. It was determined in subsequent studies that suitable calcination/recovery of sulfate production, the principal tramp product of parasitic oxidation effects in the process, requires that the sulfate be precipitated/crystallized as sodium sulfate for feed to the thermal calcination step. Tests have shown that with the typically high concentration of iron compounds present in Sulf-X Process operation, a rapid chemical reduction of the sodium-sulfate intermediate takes place at the same temperature used for calcining the sulfur-rich spent ferrous sulfide solids.

B. PURPOSE OF EXISTING PROCESS DEMONSTRATION FACILITIES: An integrated Sulf-X Process completed in 1982 is now in demonstration operation at the bituminous coal-fired boiler plant of the Western Center Hospital of the Commonwealth of Pennsylvania. The system is designed for the simultaneous control of SO_2 and NO_x emissions from one of the plant boilers at a flue gas flow rate of approximately 7000 acfm, with capability for removal of SO_2-only for flue-gas throughput in excess of 10,000 acfm. Its current test/demonstration operation in 1983 under funding by the Commonwealth of Pennsylvania constitutes a critical interim stage in the application of the process through collection of steady-state operating data in anticipation of scale-up to a later large commercial installation. The continuous operation of this demonstration facility at the same time affords a needed opportunity to study the effects on the overall chemistry of reaction products and tramp materials that accumulate in the system inventory, and to evaluate the compatability of the equipment and instrumentation installed.

C. DESCRIPTION OF DEMONSTRATION FACILITIES: The Sulf-X installation at Canonsburg is a $2 million facility dedicated by the Commonwealth of Pennsylvania to an initial 12-month period of demonstration activity in conjunction with characterization and optimization of process operation. It advantageously utilizes off-the-shelf process equipment and control instrumentation to provide a practical replica of the process facilities that are expected to be later applied in large commercial installations. Thus, the system models a large-scale installation by duplicating the primary unit operations such as gas absorption, slurry dewatering and thermal/chemical regeneration, using applicable mass transfer devices and mechanical equipment. Figure 2 shows the scrubber tower at Canonsburg and the Sulf-X Process building adjoining the boiler house at the left. Flue gas cleaning equipment operating includes a 3-feet diameter radial-blade booster fan, a lined carbon-steel gas pre-cooler, and a 73 feet high by 5-feet diameter FRP scrubber (absorber) vessel using cross-fluted fixed plastic packing. Slurry-bleed dewatering equipment consists of a 10-feet diameter lined thickener with overflow tank, a horizontal plate and frame filter containing 17 1-meter x 1-meter vertical filter plates, and a steam-heated rotary dryer (Figure 3.) The regeneration system consists of an indirect gas-fired rotary calciner (Fig.4), a calcine quench tank, and a steam-cooled vertical shell-and-tube sulfur condenser. For supply of regenerated reagent to the gas absorption system, the system includes an agitated-media type calcine-slurry crusher (attritor) and an absorber fresh-slurry feed tank.

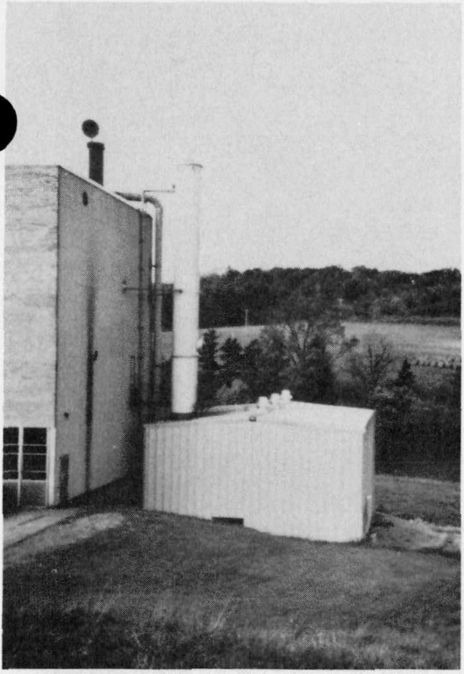

Figure 2. Sulf-X Demonstration

To simplify the overall demonstration program without adversely affecting the simulation of operation of large commercial systems, sodium sulfate crystallization facilities have been excluded. Accordingly, instead, dissolved sodium sulfate is purged from the system by blowdown, and purchased sodium sulfide is used (in lieu of sodium sulfide that would otherwise be available from calcination of sodium sulfate) to sustain the quench tank reaction, which recovers dissolved ferrous sulfate by converting it to precipitated FeS reagent. To further simplify the operation of this small-capacity demonstration operation, the calciner is fired with LPG (propane) instead of coal. Since calcination is by

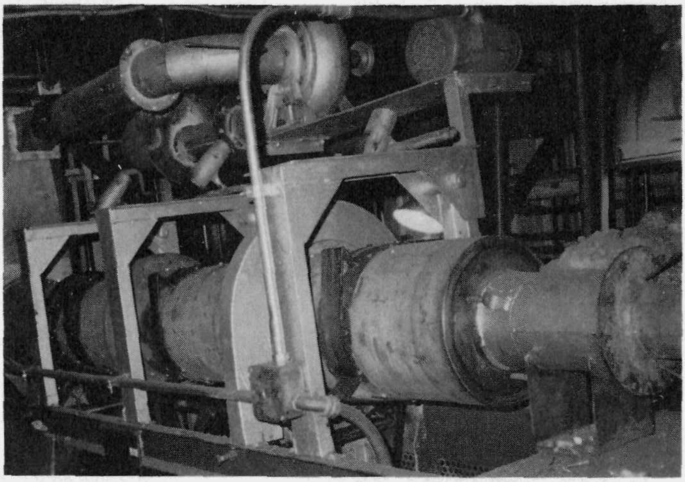

Figure 3. Steam-Heated Rotary Dryer

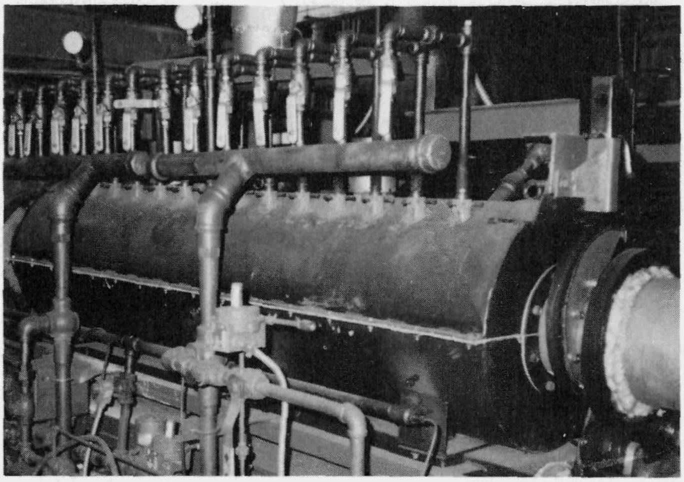

Figure 4. Indirect Fired Rotary Calciner

indirect heat transfer both in the commercial scale and Western Center designs, use of alternative fuels does not effect process chemistry or the validity of the test operations. In addition, pre-cooling and water saturation of the boiler flue gas is carried out in a simple quenching step utilizing recirculating process slurry. In absence of an isolated pre-scrubbing wastewater purge, chloride will be purged along with the dissolved sodium sulfate blowdown liquid. As a result of other simplications, calciner combustion gases are exhausted without by-product steam generation, and sulfur-condenser off-gas is recycled to the absorber inlet instead of being treated in an incinerator.

D. STARTUP PROBLEMS EXPERIENCED: Principal startup/operating problems encountered with the initial system installation are difficulties in mechanically transferring the filter cake to the dryer and in moving the filter cake through the drying operation; and the oxidation effects of excessive amounts of atmospheric air entering the process-side of the calciner. Because of the small batch-scale nature of the filtering operation at Western Center, transport of wet filter cake is expected to continue to require special operator attention during continuous process runs. The original dryer and calciner have been replaced in late 1982 with the more compatible equipment described above, and these operations are now considered to be free of major problems. Retrofit modifications have also been made to the sulfur-vapor vacuum and condensing systems to avoid solidification of sulfur before the condenser as well as carryover of sulfur liquid and vapor to the vacuum producing equipment downstream.

E. PROGRAM OF SYSTEM TESTING: The Western Center scrubber has successfully demonstrated up to 99+% removal of SO_2 and up to 93% removal of NO_x in 2%-sulfur bituminous coal service. At a superficial gas velocity in the scrubber of approximately 10 feet per second, typical of operation of commercial FGD systems, SO_2 removal at an efficiency of 95+% is accompanied by only token NO_x removal. At a superficial velocity no greater than 4 feet per second, NO_x removal efficiency is 90+% with essentially 100% SO_2 removal. The absorption system has operated automatically with the pH controller regulating fresh-slurry addition and spent-slurry removal to maintain a constant, pre-set pH. Pyrites has been used for iron makeup. During 1982 startup and commissioning activity, spent slurry has dewatered well in the thickener and filter, and the FeS precipitation and chemical makeup systems have performed as designed. The Commonwealth of Pennsylvania is expected to authorize and fund continuous round-the-clock operations beginning in the early 1983 winter months. Comprehensive data is being collected for a broad range of operating conditions to provide parametric testing to optimize system design for design NO_x removal levels up to 80%, and to yield a data base to be used for scale-up of the commonly used sub-processes that comprise the Sulf-X Process. Alternative process operation will be tested in runs that will substitute 4%-sulfur coal for boiler firing, and copperas ($FeSO_4 \cdot 7H_2O$)

for iron makeup. In additional runs, purchased sodium sulfate will be fed with petroleum and/or metallurgical coke to the regeneration system to demonstrate the use of sodium-sulfate intermediate product as the process design means for tramp sulfate recovery. NO_x/SO_2 removal efficiency will be correlated to scrubber liquid/gas ratio and ferrous ion concentration during steady-state operation along with superficial gas velocity and gas residence time.

VI. COMMERCIAL-SCALE PROCESS ECONOMICS

The Sulf-X Process is believed to offer a technically sound and economically attractive means for high-capacity regenerative FGD operation. In-house preliminary conceptual design and costing studies to date have been based on a hypothetical 500 MW(e), 3.5%-sulfur coal application. A 1982 estimate for SO_2-removal-only operation indicates a total capital investment of approximately $60 million, i.e. $120/gross kW, including indirect costs, contingency, startup allowance, interest during construction, working capital, and royalty fee. Annual costs with zero by-product credit are projected at approximately $22 million (1982-$), representing less than 7 mills/kWh, which includes approximately $4.5 million for raw materials, (primarily pyrites concentrate and coke), $0.5 million operating labor, $4.5 million for utilities, (primarily electric power and process steam), $2.5 million maintenance, $8.5 million capital charges, and $1.5 million overhead costs. (Based on anticipated sale of sulfur by-product at a nominal $100 per ton price, total annual costs would be reduced to approximately $18 million.) A 1982/3 detailed study of commercial FGD economics at the 4%-sulfur coal, 500 MW(e) level by the Electric Power Research Institute, scheduled to be published in the first half of 1983, is expected to provide an appropriate direct comparison of the economics of all principal FGD processes being studied including Sulf-X. 1979 in-house studies, on a comparable basis, for commercially available combined SO_2/NO_x removal facilities achieving 80% NO_x removal confirm that Sulf-X is substantially less costly than other available wet simultaneous SO_2/NO_x removal processes. Moreover, while capital cost is indicated to be somewhat higher than for combined removal methods that include dry catalytic NO_x control processes, the Sulf-X Process is estimated to have lower annual revenue requirements than all available combined removal methods including those based on dry NO_x control.

REACTIVE/CLEAN COAL AS A SUBSTITUTE FOR OIL

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Coal is the major source of energy within the United States and, as such, is a potential source of energy to ameliorate the energy crisis the United States is now facing. However, for this to be realized, coal must be treated to make it more amenable as a substitute for oil in boilers, heaters and furnaces, not only for the near term but also for the long term. One approach is to modify the properties of coal via chemical treatment so the resulting product is not too different from fuel oil and can be used in oil-fired boilers with minimal retrofitting and derating.

This treatment must separate the pollutants such as sulfur and mineral matter (ash) from the coal to produce a solid fuel which can be burned with little or no emissions to the environment and a solid fuel which has low fouling characteristics. In addition, the fuel must be very reactive, i.e., have improved combustion characteristics in terms of ignition, flammability and carbon burn-out. If coal is to be burned in place of oil, the coal's reactivity must be upgraded to assure complete burn-out in a furnace volume originally designed for oil combustion.

For many years, Battelle's Columbus Laboratories has been engaged in the development of aqueous processes for producing a clean solid fuel which potentially can be substituted for coal in boilers, heaters and furnaces (1,2, 3,4). The results of this work with in-house funds and industrial support clearly demonstrate that a highly reactive, clean solid fuel can be produced by chemically extracting the sulfur and the mineral matter from coal to produce a fuel which is in compliance with New Source Performance Standards (NSPS) and which has a mineral content of less than 0.5 percent. The residual mineral matter is primarily silica which has a high ash fusion temperature; therefore, the cleaned coal has a low fouling index.

Until recently, the basic approach was to contact the coal with hot aqueous alkaline solution, followed by an inorganic acid leach to extract the sulfur and the mineral matter. However, it has been discovered that under certain conditions, it is possible to prepare ultrafine clean coal products by extracting the organic fraction of raw coal from the mineral matter, i.e., by dissolving the organic fraction of the raw coal in hot aqueous alkali, and then reprecipitating a product coal exhibiting a very small particle size and very low in sulfur and mineral matter. This method is referred to as "The Water Refined Coal Process".(5) Processing details and specific details of this ultrafine clean coal as a substitute for oil are discussed in this paper.

PROCESSING DETAILS

The water-refined coal process entails four major processing steps as shown in Figure 1.

- Coal preparation
- Solubilization of the organic fraction of raw coal
- Separation of the dissolved coal
- Drying of coal product

Coal preparation entails crushing or grinding of the raw coal, as received from the mine or after washing.

The coal is then mixed with an aqueous solvent, for example, aqueous NaOH solution, and heated at a temperature and pressure (steam pressure) necessary to dissolve (extract) the organic fraction of the coal, leaving the majority of the mineral matter as an insoluble residue. The resulting slurry is then filtered before or after cooling to separate the coal from the insoluble residue.

The ultrafine clean coal product is separated from the coal solution by pH adjustment, washed, and utilized as a source of fuel either as a dried or partially dried product.

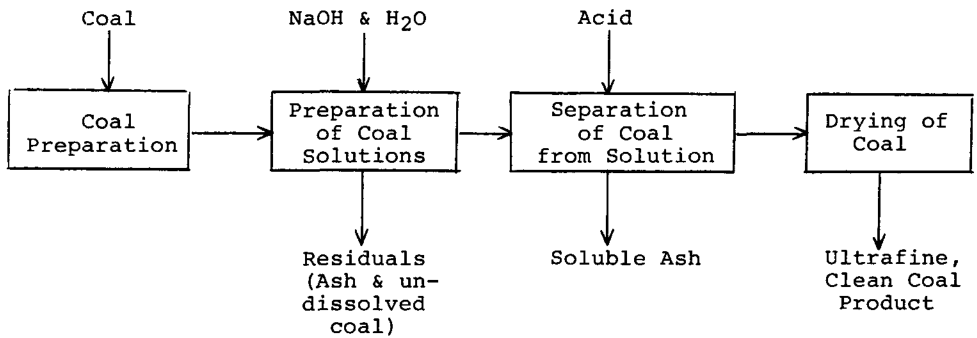

FIGURE 1. FLOW DIAGRAM OF WATER-REFINED COAL PROCESS

CHARACTERISTICS OF WATER-REFINED COAL

The water-refined coal is a candidate as a substitute for oil in boilers, heaters and furnaces because of the purity of the coal and its reactive. As shown in Tables 1 and 2, the coal product could be burned with little or no emissions to the environment. Sulfur content is low, corresponding to about 0.5 lb $SO_2/10^6$ Btu. Ash (mineral matter) content is low, approximately 0.5 percent. As shown in Table 2, the ash is composed of primarily silica at a level of about 0.3 percent. Silica is a high melting material; therefore, water-refined coal should produce an ash having a negligible tendency to form adherent deposits on the tubes. Thus, water-refined coal in terms of purity (low sulfur and low ash content) and in terms of forming deposits which can be removed easily from the tubes, meets two of the requirements for substituting coal for oil.

Some other requirements for substituting coal for oil are high reactivity and essentially complete burnout. Water-refined coal should also meet this requirement. This coal should be extremely reactive, since it is composed of particles having a size less than 0.02 microns. During the chemical treatment the coal is depolymerized, i.e., the basic coal molecule is broken down to much smaller molecules. The water-refined coal has a molecular weight in the range of 300 to 1200 with an average of about 700. Evidence from other work at Battelle on chemical cleaning of coal supports the postulation on high reactivity. In this earlier work on combustion of chemically cleaned coal (6), ignition temperatures were reduced from 425 C to 340 C. Also, these chemically cleaned coals burned out at a maximum temperature of about 470 C, whereas the untreated coals burned out at a temperature of 585 to 600 C.

This earlier work also suggests that water-refined coal should have an acceptable burnout, i.e., greater than 98 percent. In some exploratory research, chemically-cleaned coal had a carbon burnout as high as 99.9 percent when fired in a pulverized coal combustion system. This high burnout rate is attributed to the treated coal having a more simplified structure than the untreated coal. This is evidenced by the fact that liquid products from the pyrolysis of chemically treated coals contained less asphaltenes than liquid products from untreated coals. (7) For example, asphaltene content of liquid products from pyrolysis of chemically treated coals ranged from 4.0 to 6.8 percent whereas asphaltene of liquid products from pyrolysis of untreated coals ranged from 14.1 to 18.3 percent. It is expected that the lighter weight liquid

TABLE 1. COMPARISON OF COMPOSITION OF RAW COAL AND WATER-REFINED COAL

Source of Coal	Raw Coal	Water-Refined
Mineral Matter, % (MAF)	12.3	0.4 - 0.6
Total Sulfur, % (MAF)	1.01	0.3 - 0.4
Heat Content, Btu, lb (MAF)	12.300	13,500 - 14,500
SO_2 Emission, Btu/lb	1.67	0.5

TABLE 2. COMPOSITION OF MINERAL MATTER IN WATER-REFINED COAL

Metal[(a)]	Concentration, % on Metal Basis
Si	0.15
Fe	0.01
Ti	0.02
Ba	0.01
Mg	< 0.005
Al	< 0.005
Mo	< 0.005
Cu	< 0.005
Ni	< 0.005
Ca	< 0.005

(a) Other sought but not found.

products would have a lower volatilization temperature and, hence, a lower ignition temperature, both of which would increase the reactivity of the treated coal.

Another criteria in using coal as a substitute for oil is "How is the coal to be used" -- as a dry powder or as a coal-oil, coal-water or a coal-oil-water mixture. The water-refined coal could be used as either. Since an aqueous treatment process is employed to produce the ultrafine, clean coal, the obvious way would be as a coal-oil-water mixture. Some exploratory work indicates that the water-refined coal is readily dispersible in liquid fuels such as diesel oil, No. 2 and No. 6 fuel oils, gasoline and alcohol. A fairly stable diesel oil-coal slurry was produced without the addition of a dispersant by simply mixing the coal in diesel oil with a Waring blender. A stable alcohol-coal slurry was prepared by simply mixing the two components.

Preliminary work suggests that ease of dispersibility may be attributed to solubility of the water-refined coal in inorganic solvents. The coal appears to be soluble to a certain extent in alcohol and is definitely soluble in certain crude oil fractions suggesting the potential for substituting such as coal product in petroleum refining.

SCALE-UP OF PROCESS

Another basic requirement for using coal as a substitute for oil is being able to produce large quantities. While much of Battelle's work in chemical coal cleaning has been at the laboratory scale, we have demonstrated the potential for scale-up of the process. In fact, we have a pilot plant facility for producing quantities for combustion tests. This facility consists of the following unit operations.

- Coal preparation
- Solubilization of the organic fraction of the raw coal
- Separation of the dissolved coal
- Drying of coal product.

Our work in chemical coal cleaning clearly suggests that the Water-Refined Coal Process should be scaleable for the production of large quantities of the cleaned coal.

APPLICABLE TO A VARIETY OF COALS

Another requirement for using coal as a substitute for oil is that the process must be applicable for producing the reactive/clean coal from coals representing large reserves. Battelle's work in chemical coal clearly indicates that the Water-Refined Coal Process can be employed to produce the reactive/clean coal from a variety of coals. Much of our work with this process has been with western subbituminous coals. However, earlier work in which the objective was the production of an environmentally acceptable fuel for utilities indicates that many bituminous coals can be treated to produce a reactive/clean coal as a substitute for oil.

SUMMARY

Chemical cleaning of coal prior to combustion offers the opportunity for the production of a reactive/clean coal for direct substitution of coal for oil in oil-fired facilities with minimal retrofitting and derating. Preliminary work at Battelle's Columbus Laboratories suggests that such a coal can be produced by the Water-Refined Coal Process. The resulting product is a reactive/clean coal having a mineral matter content less than 0.5 percent, a sulfur content less than 0.5 percent, has a high heat content, is very reactive toward combustion, and can be delivered and combusted as a coal-water (oil) mixture and as a pulverized (dry) fuel. Furthermore, preliminary work suggests the process can be scaled up to produce large quantities of this reactive/clean coal and can be employed for treating a variety of coals representing large reserves.

Further work is required to

- Demonstrate the feasibility of direct substitution of the water-refined coal as a fuel of choice for boilers, furnaces and heaters

- Demonstrate production of large quantities of this reactive/clean coal from a variety of coals and

- Conduct large scale combustion tests.

ACKNOWLEDGMENT

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DISTRIBUTED POWER GENERATION BY BURNING COAL-CLEANING WASTE

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INTRODUCTION

The most economical way to burn coal cleanly is to clean it before burning. Heretofore the motivation for coal cleaning (or washing, preparation, beneficiation) has been to remove the ash-forming mineral matter (usually referred to simply as "ash") in order to lower the cost of transportation. Strengthening this original motivation is the growing recognition that ash causes slagging and fouling of boiler tubes which decreases their life and heat-transfer effectiveness, thus lowering boiler capacity and availability. Still more recently recognized is the capability of coal cleaning to serve as an air pollution control measure (1). With the new concern over acid rain, to which sulfur dioxide produced by coal combustion contributes to some yet unquantified degree, increasingly "deep" cleaning of coal to remove sulfurous mineral pyrites along with ash will be employed as an alternative to scrubbing the flue gases (2).

COAL CLEANING AND ITS COSTS

Coal cleaning or preparation methods in commercial use today are physical operations based upon differences in density or surface characteristics between coal and its mineral impurities. The degree to which these impurities can be removed is a strong function of the degree of size reduction or comminution employed (3); the finer coal is ground, the more mineral matter is released as discrete particles which can be removed by physical methods.

Increasingly fine comminution is increasing costly, however, not only in terms of greater power required for grinding, but in terms of additional fuel value lost to the waste stream. For these economic reasons, conventional coal-cleaning operations stop short of their ultimate capability for removing mineral impurities.

One of the more advanced coal preparation plants now in commercial operation is co-owned by the Pennsylvania Electric Company (PENELEC) and the New York State Electric and Gas Company (NYSEG). Located near Homer City, Pennsylvania (4), it uses density-based separation methods to produce the three output streams characterized in Table 1. Of these the "middlings" stream of medium-sulfur coal can be used by foreign customers and older, exempted plants not subject to New Source Performance Standards. The "clean" stream of low-sulfur, high-value, "compliance" coal goes to users under NSPC contraints. A new, important class of compliance coal customers will be producers of coal-water slurry (CWS) fuels, which are being developed as a substitute for residual fuel oil (5).

TABLE 1
HOMER CITY PLANT PRODUCTION SPECIFICATIONS

Item	Medium sulfur coal	Low sulfur coal	Refuse
Weight distribution (percent)	56.2	24.7	19.1
Energy distribution (percent)[a]	61.6	32.9	5.5
Energy content (Btu/lb dry basis)	12,500	15,200	3,400
Ash content (percent)	17.75	2.84	69.69
Sulfur content (percent)	2.24	0.88	6.15
SO_2 emission factor (lb/10^6 Btu)	3.6	1.2	65.9

[a]Overall plant Btu recovery is 94.5 percent, which includes 1 percent credit for thermal drying loss.

The waste stream at Homer City is currently being disposed by burial in a carefully monitored land-fill operation. This disposal thus constitutes not only a loss of fuel value but an additional cost to the overall cleaning operation.

The two principal costs of deeper coal cleaning mentioned above, increased grinding-power requirements, and loss of carbon value to the waste stream can be eliminated by burning the coal waste. By thus cogenerating electric power and process heat, the preparation plant can power its own enhanced cleaning operation, sell its excess power to the utility grid, and produce useful materials from the solid combustion products discharged. This distributed cogeneration can make deeper, more effective coal cleaning economically feasible. The technology which can realize these possibilities is fluidized-bed combustion.

FLUIDIZED-BED COMBUSTORS

Pioneered by the Winkler gasifer in 1922, fluidized-bed reactor technology can hardly be called new. Later the so-called "fast fluidized-bed" or fully-entrained-flow transport reactor was introduced for catalytic chemical processes such as cracking of hydrocarbons or Fischer-Tropsch synthesis. There is vast literature on such reactors. Only within the last decade, however, has the use of the fluidized bed as a combustor been widely investigated. Subsequent activity in this field has been intense, and a biennial international conference on the subject has been institutionalized.

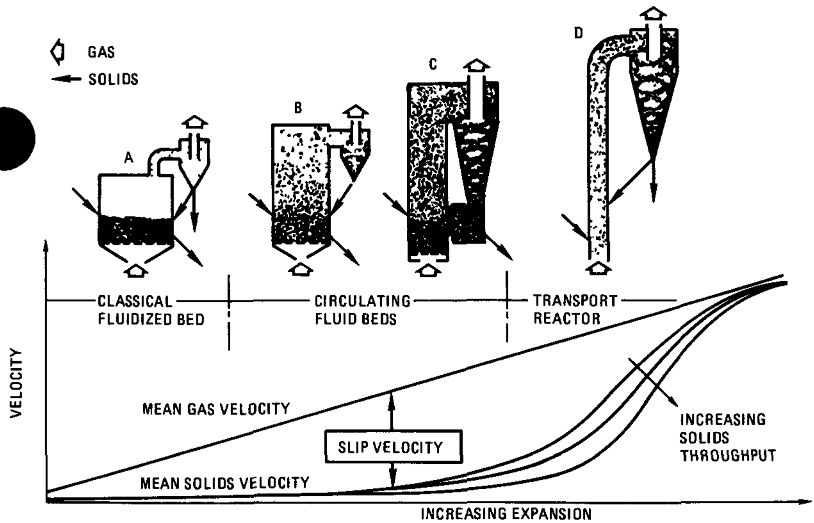

Fig. 1 Types of fluidized gas solid reactors with different regimes of particle slip velocity and degrees of flyash recycle (after Reh).

The spectrum of fluid-particle reactors is illustrated in Figure 1, and ranges from the so-called "classical" or bubbling bed on the left to the fully-entrained-flow transport reactor on the right. Until recently investigation on use of fluidized beds as combustors centered on the bubbling bed as indicated in Figure 1(A) Such beds have been the focus of several programs sponsored by the DOE of which that burning anthracite culm (6) is relevant to this paper. The test unit at Shamokin, Pennsylvania, is designed to produce a nominal steam rate of 23,000 lb/hr. As of its latest report (7), however, no combustion efficiency data have been presented.

Projects for burning coal-cleaning waste (or washings, tailings, gangue, sludge, etc.) in fluidized beds have been progressing more rapidly overseas (8-13) and the practice is becoming accepted for waste disposal purposes, with or without heat recovery. By the addition of limestone sorbent particles to the coal particles, even the relativity large amount of sulfur concentrated in coal-cleaning waste can be effectively captured as calcium sulfate.

WHY THE CIRCULATING FBC ?

Unlike noxious raw coal refuse, which can be a source of acid drainage, the mixture of ash and sulfated limestone sorbent discharged from a waste-burning FBC is a relatively inert material, disposal of which presents little hazard (14, 15). However, the quantities of solids handled will be large, and to derive the maximum economic effectiveness of the system it is desirable to put this material to benefical use. Research toward this end has been conducted both in the U.S. and abroad.

The most obvious use for FBC residue is as feedstock for the production of blended cement, which requires limestone, ash and sulfur. Other applications include road base, stabilization of soil embankments and masonry blocks (16). A much larger use could be agricultural, as a soil conditioner and plant nutrient. To render the FBC residue environmentally benign, however, requires almost complete carbon burnup. To meet rigid specifications for high-grade building materials in West Germany, for instance, the remaining unburned carbon in the residue must be less than 3 percent (17). The limits for agricultural uses presumably would be even more stringent.

With one exception (13), the waste-burning installations referenced above employ "classical" shallow bed combustors. When operating within the temperature limits required for SO_x and NO_x control, this conventional FBC is characterized by a comparatively low combustion efficiency due to elutriation of the finer coal particles out of the bed before they have burned completed. This well-recognized shortcoming is serious enough to cause commercial concern regarding overall boiler efficiency in conventional AFBC applications but becomes prohibitive where low carbon content in the refuse is essential.

It is well known that carbon burnup can be improved by increasing the recycle rate of the partially burned flyash from a conventional FBC. After some years of effort the Georgetown University plant reports a calculated (i.e. not by ash analysis) burnup of about 93 percent (18). Figure 1 shows the reason for this improvement: the unit is becoming more nearly "circulating" in character.

COMMERCIALIZATION OF THE CIRCULATING FBC

The circulating fluidized-bed reactor, oil fired, has long been used in the chemical process industries for such purposes as calcining of alumina (19), where its high heat-transfer effectiveness derives from its operation in the regime of maximum gas-solid slip velocity (20). By analogy, operation in this same regime would promote high mass-transfer effectiveness as well. Since the heterogeneous combustion of coal is a diffusion-limited process (i.e. its rate is controlled by the rate of oxygen transfer to the particle surface), it is clear that the circulating-bed reactor would also make an excellent coal combustor. An industrial demonstration of such an application recently included in the national FBC program of the Federal Republic of Germany (21) started up in August 1982 (13).

Not surprisingly, however, the vanguard of development, demonstration and commercialization of the circulating-bed coal combustor has been industry -- not government-sponsored programs. Motivated by the pressing need to utilize a wide variety of low-grade fuels, a small (2 megawatt thermal) industrial CFBC pilot plant at the Karhula, Finland laboratory of the Hans Ahlstrom Company of Helsinki was operational by 1976, followed in 1979 by a 15 MW(t) commercial cogeneration installation at a paper mill capable of operating on peat, wood wastes, coal or mixtures thereof (22). A scaled-up version of this plant producing 200,000 lb/hr of steam and capable of generating 22 MW(e) began operation at Kauttua, Finland in May 1981 (23, 24). A similar unit with a steam rate of 400,000 lb/hr and a generating capacity of 50 MW(e) is now commercially available, and one rated at 800,000 lb/hr and 100 MW(e) is under development (24).

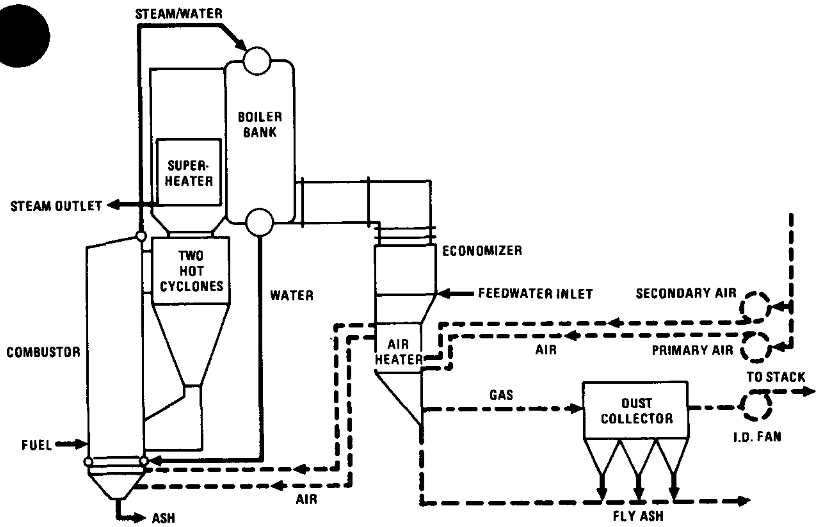

Fig. 2. Schematic diagram of Kauttua 100 t/h cogeneration plant (From Oakes, et al)

Other industrial circulating FBC systems are now also in varying stages of development. As noted above, a unit with a thermal rating of about 83 MW(t) commissioned in the FRG for molten salt reheat started up in August 1982. It was designed by Lurgi Chemie and Huttentechnik of Frankfurt, FRG and followed the design of Lurgi's earlier oil-fired reactors, but with the addition of an external, fluid-bed heat-exchanger loop.

In the U.S. a design by the Battelle Columbus Laboratories trademarked "Multi-Solid" FBC is manufactured under license by the Struthers-Wells Corporation for steam generation for heavy oil recovery. The first unit, producing 50,000 lb/hr, started up in December 1981 (25). Like the Lurgi design, the Multi-Solid FBC also incorporates an external, bubbling-bed heat exchanger for raising steam. As can be seen by comparison of the schematic flow diagrams shown in Figures 2 and 3, it is thus more complex than the single-loop Ahlstrom design (trademarked "Pyroflow") which raises steam directly from water-walls in the combustor for subsequent superheat by gaseous combustion products. A 50,000 lb/hr steam generator of the simpler water-wall type, also for enhanced oil recovery, is due for startup in

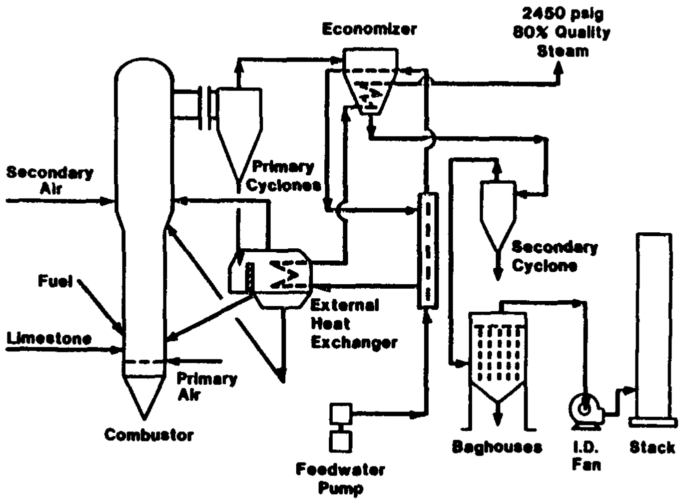

Fig. 3. Schematic diagram of 25 t/h Multi-Solid FBS plant
(From Jones and Seber)

Kern County, California early in 1983, A comparison of the economic performance of the two systems will be informative.

BURNING COAL WASTE IN THE CFBC

The foregoing discussion has emphasized the ability of the circulating FBC to operate on low-grade fuels; indeed, that was the original motivation for adapting the CFB to serve as a combustor (22). The demonstrated ability of the CFBC to burn a wide variety of low-grade U.S. fuels efficiently is illustrated in the results of 2 MW(t) pilot-plant tests presented in Table 2 (23). In particular, the tests using fuel with an ash content of 80 percent clearly demonstrate the

TABLE 2
PRELIMINARY RESULTS OF FUEL TESTS
FOR NORTH AMERICAN MARKET*

Fuel	In Dry Matter N (%)	In Dry Matter S (%)	Ca/S Molar Ratio	SO_2 Retention (%)	NO_x (ppm)	Combustion Efficiency (%)
Subbituminous coal	1.1	0.9	2.3	84	170	98.0
80% ash fuel	0.3	2.5	2.3	98	200	98.5
Ohio No. 6	1.5	5.1	1.8	90	280	98.5
Petroleum coke	1.3	3.5	2.4	90	100	97.0

*All test runs were performed at 20% to 30% excess air.

ability of the CFBC to burn coal wastes with an efficiency (98.5 percent) well above that required for use of its refuse for construction materials. Larger, commercial-size units should be even more effective in this regard, with carbon burnups of 99 percent or higher. Such high burnup has been reported for the new Lurgi unit at Lunen FRG (13).

It is informative to compare the nominal energy content of the Homer City plant refuse stream shown in Table 1 with that of the nominal design fuel for the Kauttua plant given in Table 3. It may be seen that they are virtually the same. The ability of a large CFBC to operate efficiently on coal waste is thus considered evident.

TABLE 3
KAUTTUA 100 T/H BOILER PERFORMANCE

Steam output	25 kg/s (200,000 lb/hr)
Steam temperature	500°C ± −7.8°C (932°F ± 18°F)
Steam pressure	8.4 MPa (1218 psig)
Feedwater temperature	190°C (374°F)
Flue gas temperature	160°C (320°F)
Design fuel	8 MJ/kg (3440 Btu/lb) peat
Efficiency with design fuel	86%
Other fuels	Wood wastes and coal

It should also be noted that most industrial cogeneration applications for CFB combustors employ process heat in the form of steam drawn off from an extraction or back-pressure turbine. Coal-preparation plants, on the other hand, have a limited requirement for process steam. Their principal process heat requirement would be for drying of cleaned coal fines not otherwise destined for conversion into coal-water slurry fuels (which this author submits will become a new process industry analogous to petroleum refining) but for currently conventional uses. To avoid rapid oxidation of the fines during transportation and storage, leading to internal heating and possible autoignition, their drying is desirable.

Such an operation appears easily adaptable to a typical commercial CFBC system, (cf. Figure 2) by inserting a dilute-phase suspension drying step into the flue gas stream between the air preheater exit (at about 350°F) and the dust collector entrance. Such systems have been in commercial use for many years for the drying of numerous materials including coal (26). Dilute phase suspension drying consists simply of allowing the dispersed solid particles to fall through an upward vertical draft of hot air, or, in this case, of hot exhaust products. A drying operation of this type could readily be integrated to meet the process heat requirements of a self-powered coal preparation plant.

NEW INDUSTRIAL SYMBIOSIS ?

The deteriorating financial condition of the electric utility industry is only too well known (27). In view of the current and growing financial difficulties faced by the utilities, the distributed cogeneration of power at coal-preparation plants presents an opportunity for a symbiotic relationship between coal producers/processors and coal-burning utilities. Since the Homer City preparation plant is utility-owned, it does not illustrate this potential symbiosis but nonetheless provides an example of the degree to which distributed power cogenerated at such plants could contribute a significant fraction of the total power handled by the utility grid.

Utilties heretofore have generally resisted industrial cogeneration arrangements. This reluctance is understandable, since the individual power contributions involved are often too small to be worth the nuisance of hooking them up. In the case of coal preparation plants, however, the amount of power generated by waste burning can be two orders of magnitude greater than than produced by ordinary industrial installations.

The throughput of the Homer City plant is 1200 tons per hour of raw coal, of which 19.1 percent or 229 tph constitutes the refuse stream. At the nominal energy content of 3400 Btu/lb, this waste stream represents a potential fuel flow of 15.6×10^8 Btu/hr, or enough to power more than six CFBC plants of the Kauttua size. Alternatively, if two of the newer 800 million Btu/hr plants were employed, they could generate almost 200 MW(e), only a small fraction of which is required to power the preparation plant. Contributions of this size are significant, and their aggregation would seem an attractive option to more costly alternatives for satisfying system needs, such as purchasing power from adjacent systems (28).

Most coal preparation plants, however, are owned by coal producers, not utilities, and here is where the new industrial symbiosis by distributed cogeneration appears not only possible but desirable. Sale of their excess power to utilities can make deeper, more effective coal cleaning economically viable for preparation-plant operators, and the availability of compliance coal and cogenerated power can relieve the utilities of capital expenditures for additional central generating capacity and flue gas scrubbers. The concept would appear to warrant serious consideration (29, 30).

STATE OF THE COMMERCIAL TECHNOLOGY

The seriousness with which distributed generation by coal waste burning will be assessed will depend strongly upon the degree to which the required combustor technology is judged to be commercially mature. A recent summary of the commercial status of the various FBC designs concludes that "The marketplace will decide which fits best into each application and which is the most cost effective" (21).

The commercial trend now favors the circulating FBC, because of its higher combustion efficiency and its ready scalability to large industrial or small utility sizes. The nature and operational status of the several commercial CFBC installations now existing or under contract are compared in Table 4. In addition to the three suppliers listed there, Foster-Wheeler Power Products, Ltd. of England and Riley Stoker Corporation of the U.S. have recently been licensed by Battelle to produce Multi-Solid FBC boiler units. Also, Stone & Webster is developing a "Solids Circulation Boiler" which will be commercially available in the future.

TABLE 4
CIRCULATING FLUID BED COMBUSTOR INSTALLATION LIST

Customer	Start Up	Fuel	Output	Steam Conditions	Application
		Pyroflow Installations			
ihlava Board Mill Finland	1979 Operating	Peat, wood & coal	50 MMBtu/hr	1230 psig, 970°F 45,000 lb/hr	Cogeneration
Suonenjoki, Finland	1979 Operating	Peat, wood & coal	22 MMBtu/hr	160 psig, 250°F hot water	District Heating
Kemira Oy, Finland	1980 Operating	Zinciferous sludge	—	—	Sludge Incineration
Kauttua, Finland	1981 Operating	Peat, wood & coal	220 MMBtu/hr	1235 psig, 930°F 200,000 lb/hr	Cogeneration
Hyvinkaa, Finland	1981 Operating	Coal, peat & oil	85 MMBtu/hr	160 psig, 335°F hot water	District Heating
Skelleftea, Sweden	1981 Operating	Peat, wood & coal	22 MMBtu/hr	160 psig, 355°F hot water	District Heating
Ruzomberok, Czechoslovakia	1982	Sewage sludge	8,000 lb/hr	—	Sludge Incineration
Hylte Bruk, Sweden	1982 Operating	Peat & coal	157 MMBtu/hr	960 psig, 840°F 143,000 lb/hr	Cogeneration
Gulf Oil Explora tion, USA	1983 Under Construction	Coal	50 MMBtu/hr	2500 psig, 670°F 50,000 lb/hr	Enhanced Oil Recovery
Koskenkorva Distillery, Finland	1983 Under Construction	Peat & oil	63 MMBtu/hr	610 psig, 840°F 55,000 lb/hr	Process Steam
Kemira Chemical, Finland	1983 Under Construction	Peat & oil	173 MMBtu/hr	1305 psig, 960°F 155,000 lb/hr	Cogeneration
Zellstoff Und apierfabrik rantschach Ag Carinthia, Austria	1983	Bark, Brown Coal and Sludge	188 MMBtu/hr	1250 psig, 968°F 154,000 lb/hr	Cogeneration
		Multi Solid Installations			
Maverick Co., Texas	Dec 1981	Coal	50,000 lb/hr	2450 psig, 675°F	Heavy oil recovery
		Lurgi Installations			
Luenen, W Germany	Aug 1982	Coal waste	250,000 lb/hr equivalent	950 psig, 900°F	Cogeneration

In his keynote address to the Seventh International Conference on Fluidized Bed Combustion, DOE Acting Under Secretary Jan Mares underscored reliability as the sine qua non for acceptance of FBC technology by the utility industry. He also could have stressed reliability squared as the requirement of the chemical process industries, which cannot "wheel" in process heat when a plant goes down.

Of the operational CFBC installation listed in Table 4, the small (15 MWt) unit at Pihlava and the larger one at Kauttua (65 MWt) have accumulated records of demonstrated reliability (now about 4 years and 1.5 years, respectively, at over 90 percent availability) sufficient to instill confidence in prospective industrial customers (32). These track records the other entries have yet to match, but the coming year should see hightened competition in the CFBC field, and it will be interesting to review the situation at ET-11.

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CRT BASED CONTROL OF FOSSIL FUELED BOILERS

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INTRODUCTION

The trend in control systems for modern industrial boilers has been to monitor increasing amounts of data while at the same time consolidating the panel space allowed for operator interaction. This has resulted in safer, more reliable and more efficient plants, by providing detailed information to the operator that will enable him to make informed decisions rather than best guesses. This trend will level out when the amount of data presented to the operator begins to exceed his comprehension level. The effect of this would be slower response, confusion during emergencies and increased downtime - a result exactly opposite from that intended. Microprocessor-based control systems with interactive keyboards and CRT monitors now offer almost limitless flexibility in designing control philosophy and data displays. Our ability to apply these systems in a logical and organized manner will therefore be critical in the continuation of this trend.

CONTROL SYSTEM PHILOSOPHY

The boiler control system philosophy should be based on the requirements of the steam users, the type and size of the boiler auxilaries being controlled and the capabilities and limitations of the control equipment.

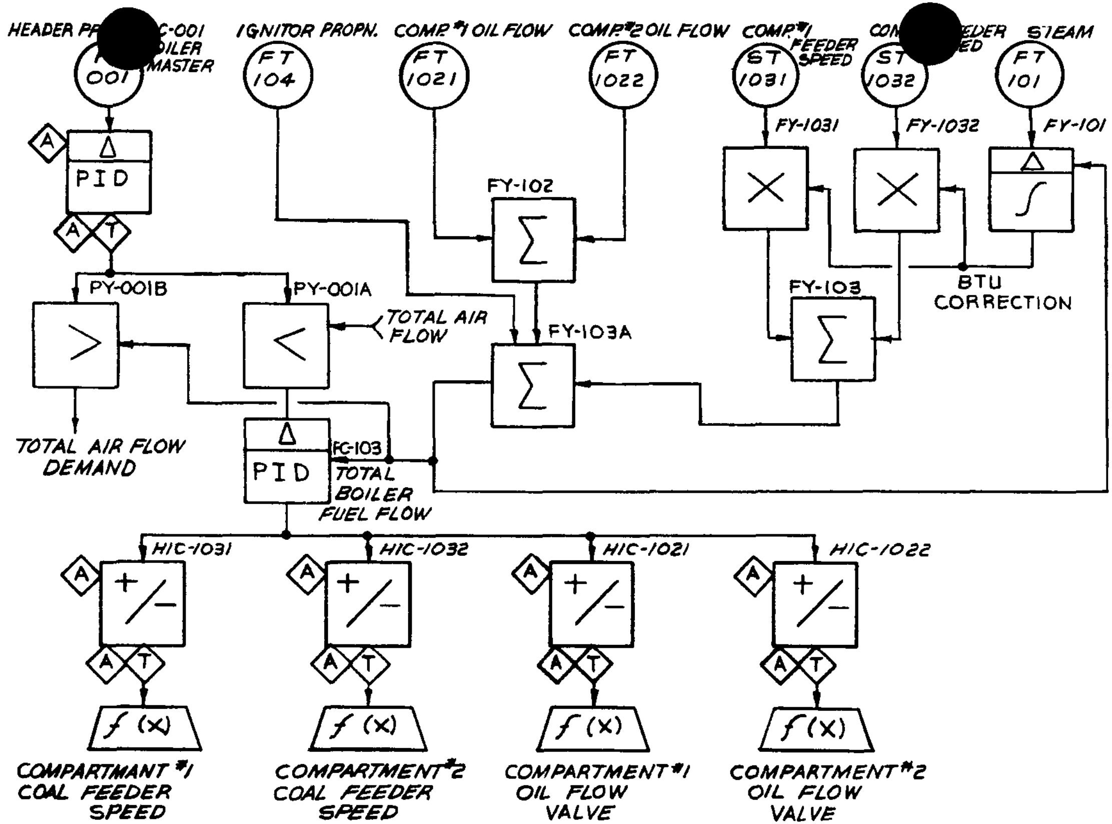
Figure 1 shows the fuel control schematic (in SAMA symbology) for a modern Babcock and Wilcox pulverized coal and oil fired boiler with a maximum continuous steam flow rating of 175,000 lbs per hour. The windbox on this boiler is divided into two compartments. Each has its own coal feeder,oil valve and secondary air damper . In a sense, its like two furnaces in one. To maintain a balance between steam production and steam usage, steam header pressure is measured and controlled to setpoint by regulating total input BTU flow and air flow in parallel.

Total input BTU flow is calculated by summing each individual compartment's oil flow and feeder speed. Feeder speed is corrected for coal BTU content by comparing total fuel flow to steam flow and integrating the error. Total boiler fuel flow is controlled by the fuel controller which modulates the individual coal feeders and oil valves in parallel.

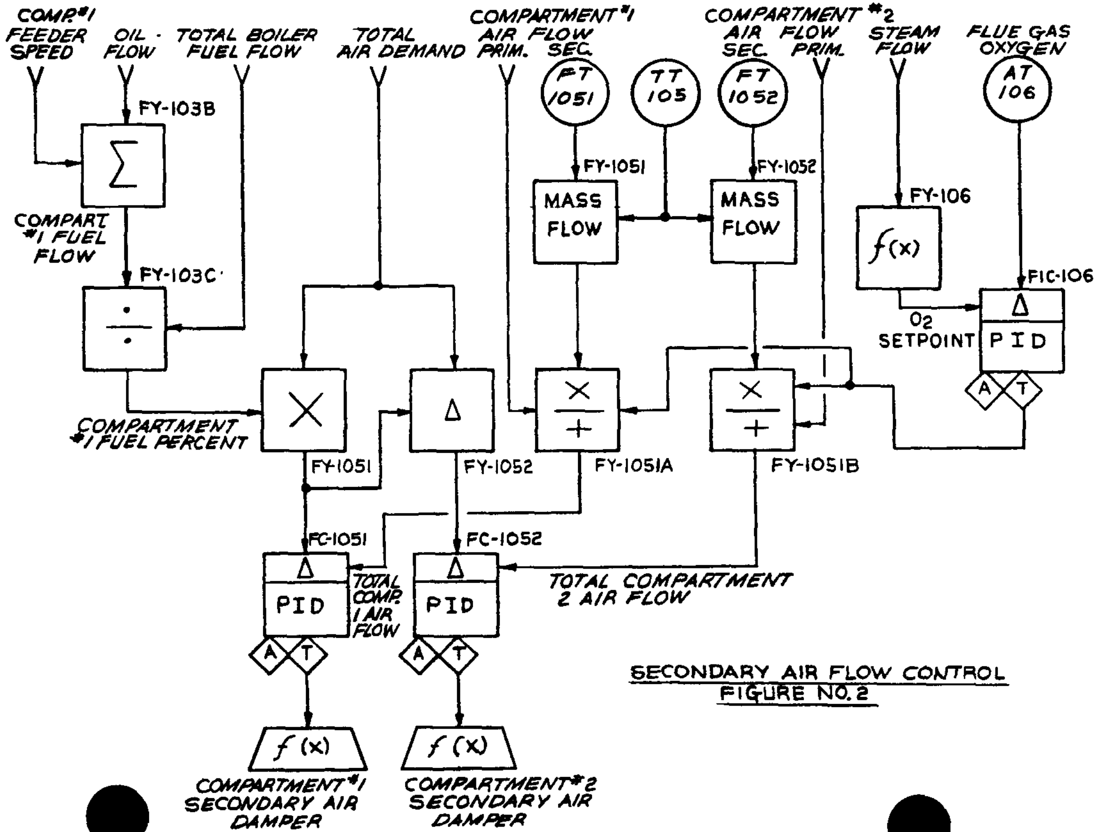
Air and fuel are cross limited to ensure that fuel flow never exceeds the amount of air entering the boiler. This is applied on a boiler basis rather than per compartment to ensure total air flow limiting.

Figure 2 shows the secondary air flow control for this boiler. The total air demand is multiplied by the Compartment #1 fuel to total fuel percentage. This calculates the required air flow for Compartment #1. This quantity is subtracted from the total air demand to obtain the Compartment #2 air flow requirement. Compartments #1 and #2 secondary air flows are measured and compensated for temperature. Oxygen in the flue gas is automatically controlled by correcting the secondary air flow signals. Individual compartment primary air flow is added to secondary air flow to provide total compartment air flow .

This control philosophy was specifically designed for this type of boiler and was approved by the boiler manufacturer before placing it in operation.



FUEL FLOW CONTROL FIGURE NO.1



SECONDARY AIR FLOW CONTROL
FIGURE NO. 2

By maintaining proper excess air and steam header pressure during steady state and changing load conditions, this control system will maximize efficiency, reliability and safety.

OPERATOR INTERFACE

Now that we understand the operation of the boiler and the automatic control system, let's see how the operator interfaces with the process.

Operator intervention is required even with the most automated control system. The following events may necessitate operator action:

1. Start-up and shutdown.
2. Unexpected trip of boiler auxiliary equipment.
3. Maintenance of on-line equipment, pumps, fans, etc.
4. Maintenance of control equipment, valves, transmitters, controllers.
5. Process measurement exceeding high, low, or rate of change limit.

Conventional control panel design has always used the area concept. That is, controllers, indicators and switches associated with a certain process were grouped together in one area. Examples are feedwater, air flow, and water treatment. Each device had a unique, dedicated location. Panels of thirty feet in length were typical. The operator would recognize first which area of the panel he needed to go to and then which switch to throw or indicator to read within that area.

The intent of this design was more for logical organization rather than ease of operations. Certainly, many operator sequences require actions in different areas of the panel.

Today's modern CRT-based operator stations allow the operator to sit in one place while using a keyboard to call up the data that is important to him at the moment. His feet are no longer required to get him to the right area.

His data is organized for him in groups on individual CRT displays. It is these displays that now provide him with the process picture necessary to do his job.

Much of the detail of display building has been taken care of by the control vendor's standard software. Character size and color, word length and orientation and update areas are all normally not configurable by the process control engineeer. This is just as well, as it eliminates the need for special programming knowledge on the part of the user.

Display building then refers to the task of selecting and organizing the information to be displayed.

DATA DISPLAYS BASED ON OPERATOR TASK

Initially, CRT displays only imitated conventional panel grouping of control and monitoring devices. They were arranged so that the operator could view a particular process or part of a process but to scan several areas he had to page through various displays. This was not full utilization of the CRT's potential as an improved operator interface.

One now has the abililty to organize blocks of data in any way that seems appropriate to the task at hand. Different tasks will require different groups. Critical variables can appear in more than one group so they can be monitored during multiple tasks. Non-essential or seldom needed points should be kept out of the normal displays.

Two operator stations, each with identical display capability, are normally the minimum required for a single boiler. This not only provides redundancy but allows for maintenance or auxiliary monitoring without interrupting the operator. As a minimum , the following types of point groups should be created:

1. Boiler Summary Groups
2. Process Area Groups
3. Start-up Groups
4. System Maintenance Groups

BOILER SUMMARY GROUPS

To view the overall automatic operation of the boiler, a hierarchy of summary displays should be generated. These will generally be used for monitoring only, although setpoint adjustment is possible.

At the top of the hierarchy would be the boiler overview group. Here the most critical of the boiler variables should be displayed. Steam, flow, steam pressure, steam temperature, total fuel flow, total air flow, excess oxygen, furnace pressure and drum level are the key boiler variables. Depending on the size of the system and the number of points being monitored, additional summary groups could be created.

These groups are intended to keep the operator informed of the overall operation of the plant, when the control system is on full automatic, and no operator intervention is required. When a particular process needs more detailed monitoring, for instance, when an alarm is sounded, the operator will call up one of the next category of displays, the Process Area Groups.

PROCESS AREA GROUPS

Process Area Groups are designed to monitor and control the individual processes. They should be similar in content and organization to areas on a conventional panel layout in that they are concerned only with one process.

In the coal control group for our subject boiler, total fuel flow, total coal flow, individual compartment coal flow and the individual compartment feeder speed hand/auto stations are displayed. Excess oxygen and the total air flow are also displayed as critical variables.

From this display the operator can bias the fuel flow on a compartment basis. He can also baseload coal flow by placing the coal feeder in manual.

Other process area groups are needed for:

Oil Control
Air Control
Compartment 1 Control
Compartment 2 Control
Drum Level Control
Blowdown Control
Furnace Draft Control
Deaerator Storage Control
Condensate Storage Control
Steam Temperature

But these are not the only tasks the operator needs to perform. Pulverized start-up is an example of another type of operator/system interaction.

For this function the operator should call up the appropriate Start-Up Group.

START-UP GROUPS

During start-up and shutdown of plant auxiliaries,it is important to monitor more closely certain variables which are associated only with the safe operation of that piece of equipment. Bearing temperatures, vibration, motor current, oil pressures and sump levels are examples. However, during normal operation, the operator need not concern himself with these points. He will rely instead on the alarms to warn him of any unusual conditions.

In the start-up group for the coal pulverizer #1.., pulverizer motor amps, pulverizer differential pressure, primary air flow, coal-air temperature, feeder speed hand/auto station and feeder speed are all needed for start-up. Secondary air flow is shown as a critical variable.

Additional start-up groups are required for F.D., I.D. and primary air fans, fuel oil pumps, feedwater and condensate pumps and air compressors.

SYSTEM MAINTENANCE GROUPS

In a conventional electronic analog or pneumatic control system, all auxiliary computing functions are performed by hardware inaccessible to the operator. Low and High selectors, multipliers, summers and function generators are usually located in a cabinet, possibly locked, that solely is the responsibility of the technician.

In modern microprocessor-based systems these functions are performed by the controllers and are accessible through the operator station. However, they should only be displayed in Maintenance Groups and any recalibration should be under keylock protection.

A Maintenance Group with all auxilary computing slots of a controller file is displayed and arranged in slot order.

All spare controller slots should also be shown in these groups. This makes spare capacity easy to locate for future utilization.

SUMMARY

Today, modern microprocssor-based control systems offer CRT interfaces that provide the boiler operator with a more comprehensive view of his plant. With proper design, this interface will enable him to perform his routine tasks with more accuracy and confidence, and to respond to abnormal conditions without unneeded delays. This will directly result in increased power plant reliability.

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A WORLD OF PROGRESS IN T&D

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On agreeing to organize a session for this 10th Energy Technology Conference, it seemed appropriate to spell out the charge that should be addressed. Reviewing the other sessions and their topics, it is apparant that the conference deals with different forms of energy -- as a resource, transformation to some other form, or utilization.

In this session we are concerned with energy in its electrical form. Regardless of how it is generated, it must be distributed to the point of utilization. Distance and quantity of power are the ingredients that differentiate between transmission and distribution.

The session title might imply world progress in T&D, geographically. Although what we will say is not necessarily limited geographically, the sense of the word is meant to cover the extent to which progress has occurred in T&D from infancy to varying degrees of maturity. There are developments foreseen in the future and I feel sure that this session will suggest a few areas of growth.

The audience of this session is probably more interested in the state-of-the-art and what to do next than in history. With this in mind, these remarks will be only brief highlights of status, progress and ideas.

TRANSMISSION DEVELOPMENTS

Modern power systems consist of complex integrated networks that handle the flow of electrical power from generating source to load, interconnect generating sources, systems, regions and pools. In accomplishing the functions, i.e., source to load, or intertie, transmission networks produce efficient transfer of electrical energy, or are a significant element necessary to maintain a highly reliable power system.

Transmission system voltages are generally considered to be voltage levels upwards of 230 kV -- specifically 230, 345, 500 or 765. In the U.S. there is an extensive coverage of either 345 or 500 kV with e 765 in the Northeast. A transmission voltage standard (U.S.) has been set at 1100 kV, but this level of voltage is not expected to become a practical reality before the 1990's. It may be significant to observe that existing commercial applications of transmission offer reliable solution to transfer of energy. More transmission might be used today to transfer power and energy from "energy rich" areas to "energy poor" areas. There is, of course, no substitute for an adequate generation source and reserve, but transmission is an alternative to consider to strengthen the power system.

Transmission systems utilize AC almost exclusively, but in the past few years several installations of HVDC (500 kV) have been realized to deliver large blocks of power, extra long distances, e.g. 1000 MW, over 300 miles. It is for these applications that HVDC is economic.

For transmission systems up through 765 kV, much manufacturer and industry research has been successfully conducted to bring developments to practical usage. Summarily, these are:

--line design, both electrical and mechanical design

--insulation contamination

--right-of-way requirements defined for acceptable radio and TV interference

--corona (visible) and audible noise

--environmental concerns

--terminal equipments, e.g. transformers, SF6 circuit breakers, surge and lightning protection, relaying, and var control (static var generators)

--systems analyses (use of computers)

HVDC -- many of the same elements of progress may be noted for DC as for AC. Significant developments that have contributed to its limited but successful application are solid-state devices to handle the conversion/inversion of current, and solid-state devices in control circuitry. A high voltage DC breaker is yet to commercially be used but its availability would probably not accelerate the growth of DC materially.

Underground transmission is in service on a limited scale up through 345 kV. Conductors could be manufactured, either oil or gas insulated, up through 765 kV, if needed. Cost ratios of UG/OH are still in the 20 to 1 range thus limiting underground to special applications.

In summary, for the transmission of electric power there has been great progress. Technology has kept up the pace.

DISTRIBUTION DEVELOPMENTS

As little as three decades ago, a common rule of thumb was -- utility system investment might be:

Generation	40%
Transmission	20%
Distribution	40%

Today, these percentages might more likely be:

Generation	70%
Transmission	10%
Distribution	20%

Distribution systems still represent a major part of the utility investment. Distribution systems include voltage levels from a utilization voltage class of 600 volts in residential, commercial and industrial -- to primary distribution up to 34.5 kV -- to subtransmission up through 230 kV. Electrical power distribution might be oversimplified to a "combination of all the lines, substations, transformers, protection equipment, etc. in a most efficient and optimized manner".

Because the installed capital investment is indeed a major part of the total investment, it is important to design and build the system cost effectively. The myriad combinations of alternatives that are possible is a large number, indeed. Modern day analyses by advanced methods using computers has made it possible to plan, design, and build systems at lower costs.

The high cost of energy in the last decade has shifted serious emphasis to lowering the cost of losses in the power system, and especially in the distribution system with the many step-up and step-down transformations required. As energy costs rise less steeply, the emphasis on transformer design losses may alter again.

Unlike transmission, underground distribution costs have been reduced materially since the early 1960's. In those days, one would hardly mention underground residential distribution because of UG/OH costs ratios of 20/1. Since that time, however, direct buried cable, padmounted transformers designed for the purpose, and protective equipment have been designed and manufactured to permit cost ratios of as low as 2/1. New construction methods have also significantly contributed to cost reduction.

Distribution systems today offer some highly interesting potential for new developments: specifically in automated meter reading, automated distribution, and feeder automation. The appearance on the scene of microprocessors and computers can change our electrical power distribution world well beyond that which we know now or can even visualize for the future. We are on the brink of many exciting developments to come in the next decade -- the distribution system will play a new role as part of the total energy management picture.

These remarks should put some perspective on T&D -- we are in a world of progress. The growth of electrical use is not inhibited by progress in T&D -- and there are still new developments to come down the road.

The speakers to follow will offer their view from a utility, a consultant and a manufacturer perspective.

It is hoped this session will stimulate some questions and new ideas.

T&D PROGRESS IN ELECTRIC UTILITIES

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When one transports his thinking back to the period about 10 years ago the whole attitude about electric power research and, in particular, the research needs of transmission and distribution technologies were radically different than they are today. In 1973, two of the principal concerns of T&D engineers were broadly focused on the needs of utilities for higher voltages and higher currents. There was an inexorable move towards higher distribution voltages and those who formerly opposed such a move had nearly all given up: the debate really centered on how high distribution voltages should go. In transmission circles, the largest concern was focused on what should be the next overvoltage beyond the embroyo 765 kV transmission systems and philosophical debates were exploring what the ultimate overhead transmission voltage might be.

At the same time engineers were pursuing research concepts that would permit the utilization of much higher currents. There was a clamoring demand for higher rated circuit breakers. While 63 kA breakers were available, utility transmission planning engineers in particular were projecting a need for 80 kA, 100 kA or even 120 kA breaker ratings to handle the load growth of the coming decade. In parallel with this there was also a chorus of demand for economic fault current limiters that could be applied to limit breaker duties until such higher rated breakers would become available. Moreover, the demand for fault current limiters encompassed all voltage levels from 13 kV on up through the highest transmission voltages.

Then came the OPEC bombshell of $10 a barrel oil! (Sounds cheap today.) All of a sudden residential electric bills began to become very visible components in household budgets. Even quicker the impact of increased costs of electricity led to extensive efforts on the part of industrial and commercial consumers to reduce their usage of electricity by the application of intelligent conservation concepts. Very quickly the formerly sacrosanct 7% a year national growth in electric energy generation disappeared. As the previously highly predictable load growth shrank, so did the demands for higher voltages and currents. Slowly but surely the emphasis in T&D circles swung from the previous emphasis on more to a new emphasis on less. Not less electric energy but less losses in power systems, less cost for the installations, and less cost for maintenance for existing systems.

In parallel, yet another new concern began to take the center stage. The national demand for an overall improvement in our environment, i.e., a demand that we clean up our water supplies and improve the appearance of our surroundings. Protection of the environment was not a new thought to the power industry; it had begun a clean up of our atmosphere by pioneering electrostatic precipitators on coal burning plants in the early 1930's. But now the standards became much more restrictive and the cost of compliance became much higher. In fact, if we retrace our thinking just a little further than 1973, we find that the environmental movement forced the conversion of coal burning plants to oil burners, starting in the middle sixties, just in time to create a demand to convert oil burning plants back to coal to reduce our national dependence on imported oils!

The nearly worldwide inflation launched by the 300% increase in the cost of oil in 1973 (and a further 200% later on), coupled with other problems of the electric power industry, caused a complete reevaluation of our industry's needs as cited above. The Electric Power Research Institute (EPRI) was born in late 1972 and had just initiated a research program, based on pre-1973 inputs from the industry. Since it was in a good position to shift gears and adjust to the new needs of the industry, in a timely fashion. This of course took place across all technical disciplines, but the balance of this paper will concern itself with the T&D area.

With the foregoing factors uppermost in mind, the emphasis at EPRI took a definite shift although it may not have been obvious until the later 1970's. For example, the early emphasis on fault current limiters abated and our emphasis in this area shifted to the design of lower cost switchgear with improved characteristics for the present size of current interrupting duties. This resulted in the present intermediate voltage SF_6 "super puffer" breaker currently being marketed by Westinghouse and was also the basis for our present work in pursuing more reliable, quicker and less expensive operators for all switchgear.

In our high voltage work at Project UHV, the early emphasis was on 1500 kV ac with some concern over whether there might be a need for studies at even higher voltages. Although some of the work done at Project UHV in the late '70s was at the 1500 kV level, the emphasis at that facility shifted more toward the 1000 kV level and much of the work carried out there has practical implications on the 765 kV and 500 kV systems already in existence. At the present time that facility is pursuing research of a similar nature for dc transmission in the voltage ranges above $\pm$ 600 kV.

Traditionally, when the power industry approved new voltage levels in overhead transmission, there quickly followed a demand for insulated cable at that voltage level as well. Consequently, the early emphasis in EPRI's underground research program included an evaluation of how much higher present types of cable systems could conceivably go. Moreover, if the voltage levels could not be raised substantially above existing levels, early emphasis concentrated on larger blocks of power at those voltage levels. By the mid-1970's, the emphasis switched to the more conventional levels. A 750 kV pipetype cable has been developed and is now undergoing field trails at Waltz Mill. This is a new insulation, a sandwich of polypropylene film and very thin layers of Kraft paper (PPP) and we are now pursuing its application for upgrading all existing pipetype cable systems at more conventional voltage levels of 138-345 kV. Perhaps that effort is a good symbolic indication of the emphasis on reduced cost of existing systems because it permits possible increases in block power transfers, utilizing the oil-filled pipes that are already buried in many of our city streets. The lower losses and thinner wals, made possible by PPP insulation, permits such increased power transfers.

In a similar vein, there was an early interest in either resistive cryogenic or superconducting cables in order to be able to move much larger blocks of power through single, three-phase cable lines. Emphasis soon shifted away from these designs towards improvement of conventional cables. We have, of course, continued some low level studies of materials for superconducting cables for possible future use.

Surge protectors for power systems provided yet another example of a change of emphasis. First, the early interest in surge protection for voltage levels of 1000-2000 kV diminished. In its place came the desire to speed to the marketplace cost effective metal oxide arrestors that would help reduce the BILs of both transmission and distribution lines and equipment. From these efforts came the gapless, zinc oxide arrester first marketed by Westinghouse as a result of cofunded research in this area. At transmission voltage levels these arresters are less expensive than the previous carbide arresters, are physically smaller, and have such reproducible spillover characteristics that they provide much better protection.

At the distribution level we entered into a materials study with McGraw-Edison aimed at developing competitive, metal oxide arresters for distribution systems. This work resulted in the development of such arresters and the construction of a plant in Olean, New York to produce such distribution arresters. While these arresters are not yet as inexpensive as the gapped carbide arresters they are intended to replace, they do have several advantages including the ability to be designed as a dead front unit which makes them very attractive for padmount installations. We believe that eventually the improved protection and reduced BILs that these arresters make possible will lead to their complete penetration of the distribution market.

At the time of the formation of EPRI, the industry was already supporting a dc transmission project under the Electric Research Council. EPRI has continued research in this area throughout the last 10 years and our research contracts are responsible for many component improvements which are now showing up on dc transmission installations. These include a metallic return transfer breaker and larger thyristors (both in voltage and current) to reduce the cost of terminal equipment. We have also pioneered the development of light-fired, large power thyristors which we expect to see in dc transmission terminals in the near future. Ongoing work includes system type studies, particularly of multi-ended dc lines and the development of a dc circuit breaker. Incidentally, 9 different dc transmission lines were out for bids or under evaluation in the U.S. alone last year.

Perhaps one of the more lucrative fields of T&D research has been the attack on the costs of construction and maintenance of T&D facilities. For transmission line construction work we have brought into being in Haslet, Texas the Transmission Line Mechanical Research Facility (TLMRF). We believe this to be the best tower test facility in the world today and it will also serve as a research facility to optimize the design of transmission structures and to develop better stringing techniques, particularly for bundled-conductor lines. Research will also be conducted at the site on new concepts in transmission structure foundations and on cheaper ways of installing such foundations.

In parallel with the development of TLMRF we have also developed a "Transmission Line Design Workstation." This facility, which can be readily put together by member organizations with relatively inexpensive computer hardware and EPRI developed software, allows a transmission line designer to almost completely design a line without leaving the office.

To simplify the problem of installing cables in city streets, we are now completing the development of an underground radar system which will permit a good evaluation of buried structures beneath city streets before excavation is begun. In this way the least expensive routes can be selected and the cost of such installations reduced. Also, we are at the final stages of development of a concrete cutter, using a pressurized water jet technique, that will greatly reduce the cost of trenching in city streets. Moreover, we believe the water jet cutting techniques will have many other applications in the construction business.

On the distribution side of the house, construction costs have also been attacked. A cable plow has been developed and should be marketed this year which we believe is a vast improvement over many plows available today. It is self-contained on a small, compact, caterpillar track machine which can get in to do a plowing job formerly inaccessible. It should be able to plow-in cables up to 42 inches deep, in almost any kind of soil, and also has the ability to install multiple cable in one pass, even at different depths, if desired. It is also a versatile tool with attachments that, for example, permit it to drill pole holes and then pick up distribution poles and set them in these holes.

One of the big problems facing many utilities today is the unexpectedly short life of much of the distribution cable that has been installed in the past 20 years. On many systems, there are now frequent failures of such cable after anywhere from 2-10 years of service in the field. The construction cost of replacing this cable is often exacerbated by the plantings or structures that customers have installed on their properties after the cable was installed. As a solution to this problem we have pioneered the development of a tool to follow such a cable, creating a temporary "duct" in the earth around it and permits it to be pulled out while using it as a pulling line to pull in its replacement, without distrubing the surface of most of the run of the cable. This product is, we believe, commencing final field trials now and the contractor, Flow Industries, has taken a license to manufacture it. It may be commercially available this spring or summer.

We also have under development a "guided mole" that would be used with the same power pack that powers the "cable follower" above, which will be able to create temporary earth ducts for as much as a couple of hundred feet, which allows the installation of new cable under railroads, highways, etc. without the necessity of any significant excavation. Its readiness for the commercial market is probably still a year away.

Even very mundane problems of maintenance on a T&D system can be expensive. Since the T&D system itself is so ubiquitous, any solution to mundane maintenance problems can produce enormous savings. One example of this is our research contracts that developed tree growth retardants that will slow the growth rate of most U.S. shade trees without permanent damage to the tree. The utility industry spends literally hundreds of millions of dollars annually on tree trimming budgets. Where applicable, the tree growth retardant treatments can save from 40-70% of these expenditures by reducing the frequency of the necessary trimming. Another example is the frequent necessity to replace (or reinforce) wood poles on either distribution or transmission lines as a consequence of "ground line rot." This pole disease, which is really an attack of the wood structure by any one of several fungi, can destroy poles in a relatively few years. A treatment has been developed for an inexpensive, in-place treatment of wood poles with fungicides that prevent this type of deterioration. The treatment appears to be effective for periods of 5-10 years and can be repeated as necessary. The cost of such maintenance is only a tiny fraction of the cost of replacing the pole.

Serious attention has, of course, also been focused on research that would permit a reduction in the losses on power systems. The single largest component of power system losses in the T&D system are transformers. It is estimated that the typical retail kilowatt hour passes through five transformations between the generator and the customer's meter. Under full load conditions the losses in an individual transformer can be as high as 1% of the put-through energy. Consequently, there is a large target for energy saving in improving the efficiency of transformers.

Conventional means of reducing transformer losses, for example, by putting more material in the transformer, has been attacked by individual utilities by including losses evaluation as a factor in purchasing transformers. However, from a research standpoint, a much larger "carrot" appeared on the horizon about five years ago. At that time EPRI entered into a development contract with Allied Corporation to try to develop amorphous steel for transformer cores.

Amorphous metal is made by chilling the metal from the molten state to a solid at such a rapid pace that no crystal lattice can be formed. The cooling rate is in the order of 500,000 degrees per second. Amorphous metals have some very interesting and different properties from their crystalline cousins and, in the case of transformer steel, one of these different properties is extremely low iron losses. In laboratory samples the reduction in losses can be as high as 80% when compared with the best grades of high-silicon steel. However, we anticipate that about 65% iron losses reduction will be achievable in a finished transformer core.

In modern transformers the copper losses are usually somewhat higher than iron losses. However, from an energy viewpoint, the copper losses are a function of the load on the transformer while the iron losses are unvarying as long as the unit is energized. We are now engaged in contracts with leading suppliers to develop both power transformers and distribution transformers with amorphous steel cores and we anticipate prototypes of these units to be in service on power systems within the next three years.

In summary, our rapidly changing economy in the past 10 years has dictated a change in the direction of research and the utility industry has shifted its emphasis as necessary and will continue to do so in the future.

PROGRESS IN TRANSMISSION & DISTRIBUTION
THE MANUFACTURER'S PERSPECTIVE

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It has not been too long since the excitement in the world of power systems stemmed from continuous, compounding load growth. REDDY KILOWATT was hard at work promoting the merits of electrification to all classifications of customers, and the utilities were reaping the benefits of scale economics borne from growth. The real challenges then were to ensure that adequate generation and transmission facilities would be on-line at the right time, and that the distribution system could be expanded quickly and reliably in order to provide a high degree of service availability to the growing load.

The manufacturers of transmission and distribution equipment saw the same excitement, because the rapid growth of electrification brought with it increasing market size and a developmental effort directed at equipment size. Bigger substations required greater capacity transformers and circuit breakers; and transmission of greater amounts of bulk power required higher transmission voltages and the resultant increases in insulation, line design effort, overvoltage protection, and protective relaying schemes. In distribution, conversions to higher primary voltage required equipment of greater capacity and impulse withstand; and a word called "beautility" was born as utilities scrambled to clean up the landscape by putting their expanding distribution systems underground. This rapid undergrounding required accelerating effort in transformer and cable termination development. All-in-all, that time of growth was a period of remarkable progress in transmission and distribution.

Today, it's all changed. While our vocabularies still include terms like "load growth", "expansion", and "housing starts", there no longer is any urgency implicit in their use. The market drivers which used to excite the manufacturers of T&D equipment are more nearly depressants rather than the stimulants they once were.

At first glance, one would assume that the key problems of the past ten years: galloping inflation, rapidly escalating plant and fuel prices, the nuclear "moratorium" and the generally stagnating economy which brought load growth to a screeching halt would also have sounded the death knell for progress in transmission and distribution. Nothing could be further from the truth. From the manufacturer's perspective, progress in T&D shines today as brilliantly as it did in the past. It does so not because of growth projections, but surprisingly because of those same negative factors in the economy which retard growth. In transmission and distribution the progress is coming from a need to "do it smarter" rather than a need to "do it bigger".

What has happened in these recent years is that the emphasis in the utility strategic planning process has shifted from the generation side to the demand side. The utilities are confronting the need to serve the existing and future load without the luxury they once had of expanding generation plant; they have to market kilowatt-hours when it is attractive to do so; and they must raise the efficiency of their systems to levels that the past never would have seen. They must accomplish all of this in a regulatory climate that has become more probing, and certainly much more involved in demand side activity.

In transmission, nothing is more typical of progress than the recent rapid growth of high voltage, direct current (HVDC) transmission. While HVDC has been a reality for some time, the conditions of today absolutely require the enlarging focus that HVDC is receiving.Without generation expansion, power import becomes paramount. If our neighbors in Canada have abundant, low cost, hydro power available, HVDC can bring it into this country reliably and economically. If we can convert coal into electricity at the mine rather than transport the coal to sites in more populous areas, HVDC brings the energy into the transmission grid. And if there is a need to interconnect distant systems without the typical concerns and associated costs of ensuring system stability, HVDC does it better.

With this continuing growth in HVDC, the manufacturer is increasing his effort in equipment and control improvements. The 1.8 kV cells of yesterday have become 4.5 kV cells today, with 1800 ampere capability. These developments have brought terminals of greater reliability and efficiency improvements of nearly 40%.

Enhanced control has also been effected. Today, HVDC is completely compatible with nearby generation and eliminates concern over subsynchronous resonance with the ability to introduce subsynchronous damping, if required. The ability also exists today to apply HVDC to AC systems of low short circuit capacity without the need for applying synchronous condensers or static VAR control.

And the progress is continuing. Expansion flexibility is being enhanced with multiterminal capability. The future will bring valve elements of increased voltage rating and current carrying capability; and more efficient heat transfer with two phase cooling.

The same conditions which have created the rapid growth in HVDC have also focused considerable attention on static VAR compensation. While the traditional benefits like flicker control continue to require the speed of static VAR compensation, its role in providing dynamic voltage control has become more important with the diminishing amount of new transmission plant being added to the system. Furthermore, the application of static VAR compensation brings the transmission system a dramatically increased transient power transfer capability. To obtain the same capability would otherwise most likely require the cost of installing an additional transmission line --- a not too cost-effective alternative.

There have been some new ways to build static VAR compensation systems as well. Mechanical switches can replace thyristors for switching capacitors, thus reducing losses. The mechanically switched capacitors can be applied at transmission voltages, with the thyristor controlled reactor and filters on the lower voltage bus. This can result in reduced transformer rating requirements.

Elsewhere in transmission, there has been considerable progress made in optimally dispatching power through the transmission system. The amount of power that can be sent through a transmission line is a function of the line's short and long term emergency rating. These ratings have essentially been determined by the calendar. In a joint project by Niagara Mohawk, ESEERCO, and GE, a conductor temperature sensor was developed which senses the conductor temperature, encodes the value and transmits the data to a repeater, which can couple into a telephone line and send the data to a central point. The temperature information is processed with the appropriate software, resulting in a better evaluation of the actual short and long term emergency rating of the line. This will show a substantial benefit in reducing generation cost.

GE, in conjunction with AEP, has also developed a new zinc oxide arrester to be applied directly on transmission towers in areas of high footing resistance. The arrester will help prevent line outages due to flashover - a real benefit especially on multi-circuit towers. The arrester also functions as a strut and can help facilitate upgrading on those towers where it is installed.

One cannot discuss progress in T&D without also reaching into the generating plant. Back in the days when energy had low cost, drive motors in power plants operated at full bore, with mechanical devices to control the process. It would not be unusual for the prime mover to be working two or three times harder than required for the particular function. But with the skyrocketing price of energy and increases in semi-conductor technology, solid state controllers are now available which deliver precisely the power required to drive the motor at the speed and torque required for the process, with very little energy lost. The overall owning cost of adjustable speed drives in power plants is proving to be quite attractive in these energy conscious '80s.

The increased focus on the demand side of the power system that today's economic climate has spawned has resulted in a most dramatic change in the distribution system. The impact has been felt the greatest by the most fundamental constituent of the distribution system - the distribution transformer.

Historically, the designers of distribution transformers were driven by the need for meeting thermal capacity and impedance requirements. Within these constraints, the efficiency of the transformer was fixed. Because system costs of the past were low, an evaluation of transformer efficiency would have been negligible.

As the utility industry progressed through the turbulence of the seventies, the need became apparent to make a total owning cost evaluation of transformers. Today, practically every utility adds to the purchase price of the transformer, a cost of losses which reflects the utility's present and future energy cost, capacity cost, and loading practice.

The manufacturers could not serve a market driven by efficiency constraints with only a few transformer designs for each rating. Not only were designs of significantly higher efficiency required, but the widespread variation in costs of losses throughout the industry demanded that a multiplicity of designs be made available. Thus was born a renaissance in transformer manufacture that is continuing today. The manufacturer must possess the capability of producing transformer designs optimized for every owning cost and, more importantly, he must be able to move his design capability with the dynamic movement of efficiency evaluations that is ongoing.

Because the importance of efficiency continues to grow,future developments in technology hold the promise of efficiency improvement only recently considered theoretical. The General Electric Company today is working with EPRI on a project to develop prototype distribution transformers whose cores are made with amorphous metal. While the loss reduction capability of amorphous metal is certainly real, we should all understand that the ultimate commercialization of those transformers is still quite a way off because it will depend in part on the direction that loss evaluation values will take, as well as the price of amorphous metal and on advances that may be simultaneously occurring with silicon steel technology. Nevertheless, this entire transformer renaissance is an outstanding example of tremendous progress being made because of the need to "do it smarter".

The same loss evaluation techniques employed by the utilities in transformer evaluation are today being used to render existing equipment into economic obsolescence. Primary conductors, for example, which have historically been selected as a function of their thermal capability <u>must</u> now be selected by economic loading constraints. Any conductor today operating close to its thermal limit has far exceeded its economic limit. The same holds true for distribution transformers. Most importantly, the industry now possesses the techniques by which economically obsolete equipment can be retired. For example, distribution transformers manufactured prior to the efficiency renaissance possess losses much greater than what is available today. Despite the fact that a 1960 vintage transformer in a utility's inventory may have some physical life remaining, it should be committed to the economic scrap heap rather than be placed into service, because the present and future economic conditions favor retirement.

Power capacitor technology has not been exempt from the efficiency improvement required today. In fact, the entire history of power capacitor technology has been one of continuous improvement in efficiency. Even though recent mandate requires the removal of PCB impregnated capacitors from the distribution feeders, economic reality was forcing the retirement of the older, paper-dielectric capacitors with an efficiency of 2.25 watts/kVAR in favor of the all-film dielectric capacitor with a significantly improved efficiency of .13 watts/kVAR.

The dramatic shift in emphasis to the demand side of the system has brought with it a growing need to modify the shape of the load duration curve to avoid the overuse of less efficient, peaking power; to save energy; or both. Many utilities today are evaluating the benefits of, and installing load management capability. Either directly by controlling devices such as water heaters and air conditioners, or by influence with the establishment of time of use rates, the utilities are requiring the products that will make load management work. Today, time of use meters are available, as well as control, command and communications systems to implement direct load control.

Load management brings with it a growing need for point-to-point communications within the distribution system. This communications capability, whether by radio channel or by carrier, provides an interesting outlook for the future of automation within the distribution system. Again, we must be able to "do it smarter" in order to optimally load substation transformers, shift line segments from source to source, and feeder to feeder and to improve system control, monitoring and protection.

These are but a few of many examples that could be cited in a discussion of today's progress in transmission and distribution. Everyone recognizes that progress will always be a function of the times; but what is happening today in response to the low growth and negative economic factors faced by the industry is a truly remarkable example of a bond between the utilities and the manufacturers - a bond of mutual understanding and cooperation; and a bond that holds great promise for the future.

PROGRESS IN CONSTRUCTION AND DESIGN

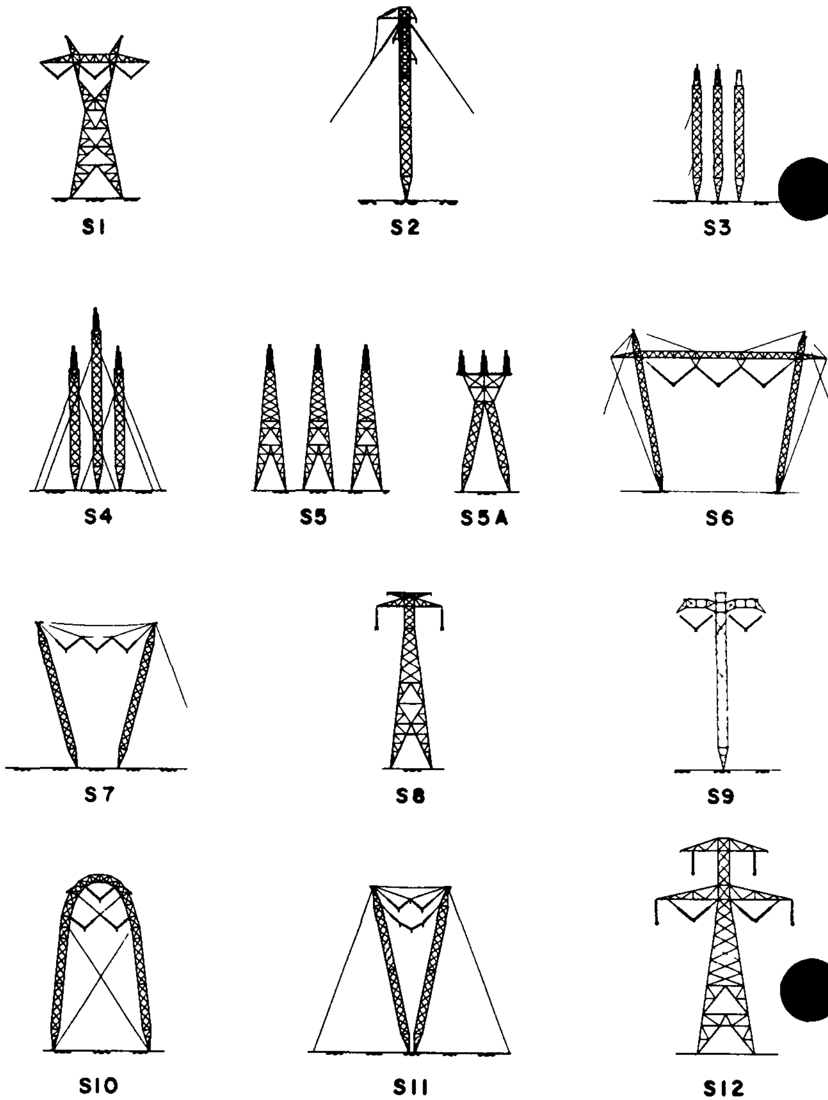
Robert W. Flugum
Chas. T. Main, Inc.
Boston, Massachusetts

The last decade has not brought dramatic strides in the transmission line and substation construction methods. There are, however, several unique and worthwhile developments on the near horizon which could impact construction costs significantly, particularly in the underground transmission area. There are two dominating reasons why the construction technology has remained more or less dormant during this decade:

1. Line and substation construction has, because of low electric load growth, been at a very reduced level of activity.

2. Regulatory and public resistance has slowed many transmission line projects - delaying some as much as 5 to 10 years.

In spite of the relatively small amount of domestic construction, new design adaptations and approaches have moved resolutely and sometimes excitingly ahead. In particular, the need to increase power transfer capability (power density) over new and existing transmission corridors has forced creative thought to be channeled toward reconstruction rather than construction. Specifically -



STRUCTURE CONCEPTS
FOR
INCREASED POWER TRANSFER

- Transmission line design has evolved almost completely - at least for 345 kV and above - to economic considerations revolving around environmental limitations, losses, and lowering of right-of-way requirements. Computer programs combining these factors into optimized solutions have been developed and are now universally in use.

- New structure designs achieving compaction and/or economic conversion to higher power density lines are being considered and adopted.

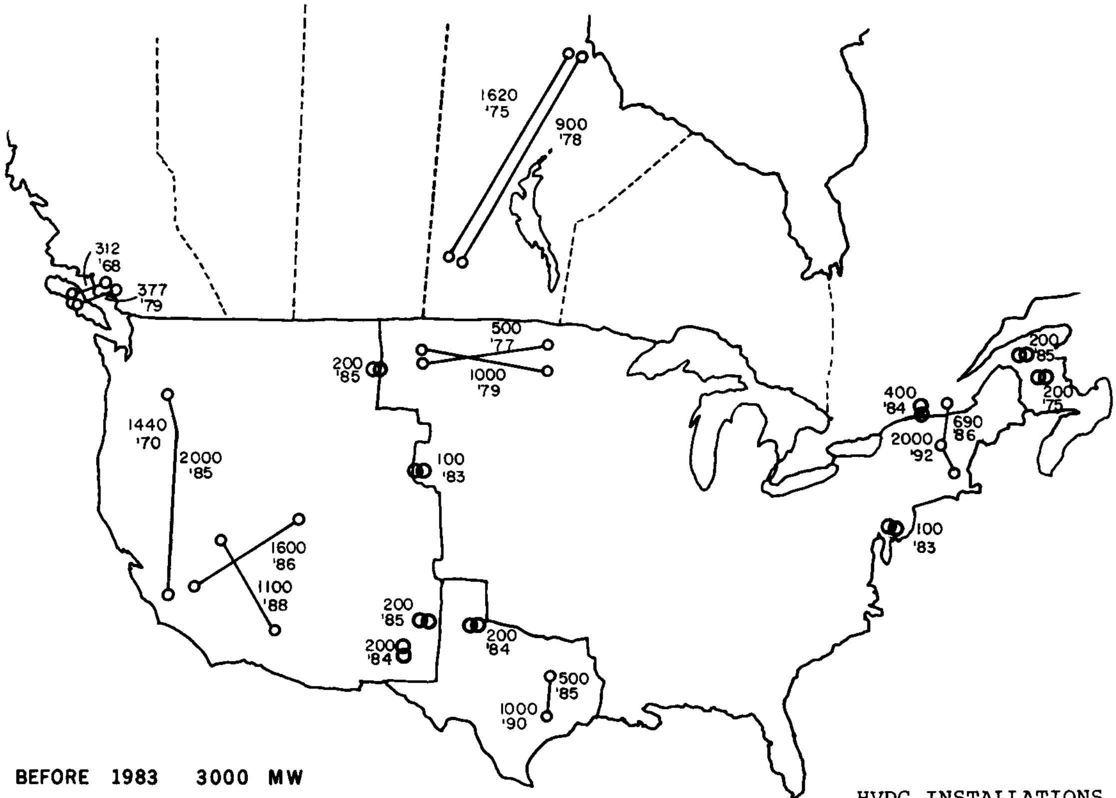
- High voltage circuit current (HVDC) transmission has - in the last two years - dominated the transmission activity in the U.S. and Canada, a direct result of the regulatory and environmental constraints and pressures on the electric utilities.

- Substation construction which a decade ago appeared to be moving toward gas insulated enclosed designs aimed at reducing space requirements and improving reliability has relied more on conventional air insulated designs primarily because of cost differentials and less of an emphasis on substation appearance and land usage.

The environmental aspects of transmission lines, which now dominate design and construction philosophies, are corona and electromagnetic field effects. Corona can cause radio and TV interference as well as low frequency noise audible to those who live nearby. Electromagnetic fields, characterized as either electric or magnetic, the first a result of line voltage and the second line current, are fields at ground level which can result in induced voltages in large bodies under and near the line and in fences which parallel the line for some distance.

The design parameters which affect these various factors do not affect each in the same way, thus, what reduces one may increase another. A larger conductor, for example, reduces radio noise levels but could increase electric field levels. It is the trade-offs possible in each of these design variables which has resulted in the development of computer programs which achieve reasonable optimization based on required limits, losses, and economies. New approaches using computer aided interactive design will soon include detailed tower member design and tower spotting techniques in their menus.

In the sixties and seventies, it appeared that the requirements for increased transmission capability would be met with another step in voltage - to the so-called ultra-high voltage levels above 765,000 volts. Several



BEFORE 1983 3000 MW
1983 19[illegible] 3700 MW
BY 1[illegible] 12000 MW TOTAL

HVDC INSTALLATIONS
[illegible]N
U.S. [illegible] CANADA

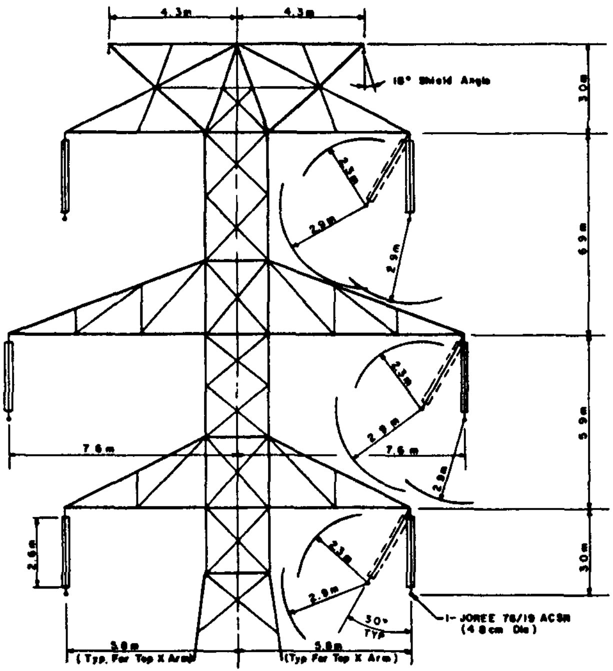
research projects investigating line and equipment performance for the 1200-1800 kV have been operational for several years, among them Project UHV, an EPRI facility at General Electric in Pittsfield, MA, the AEP-ASEA Project in Fort Wayne, Indiana, and the Lyons Test Line, operated by Bonneville Power Administration in Oregon. In spite of this intensive effort, however, the probability of higher transmission voltages being used in the U.S. grows smaller and smaller with each passing day. The dramatic and apparently lasting reduction in electric power demand, the pressure from the public against new transmission lines whether because of fear of effects, or just plain "I don't want it in my backyard", and finally, alternate approaches to increasing power density all have combined to keep UHV in the laboratory, very likely forever. The research has not been completely wasted, however, since almost all of the work has direct application at lower voltages.

The alternatives to UHV which include higher phase order circuits, upgrading in voltage, rebuilding single to double circuits, reconductoring, and conversion to HVDC all require construction and design philosophies not utilized to any degree in the past. In particular, higher phase order circuits can increase power density by a factor of 2 or more depending on the number of phases occupying the space. It is still unknown whether such circuits will be widely used or whether they are an experimental curiosity primarily because of the difficulties involved in maintaining phase spacing both on the line and in the substation.

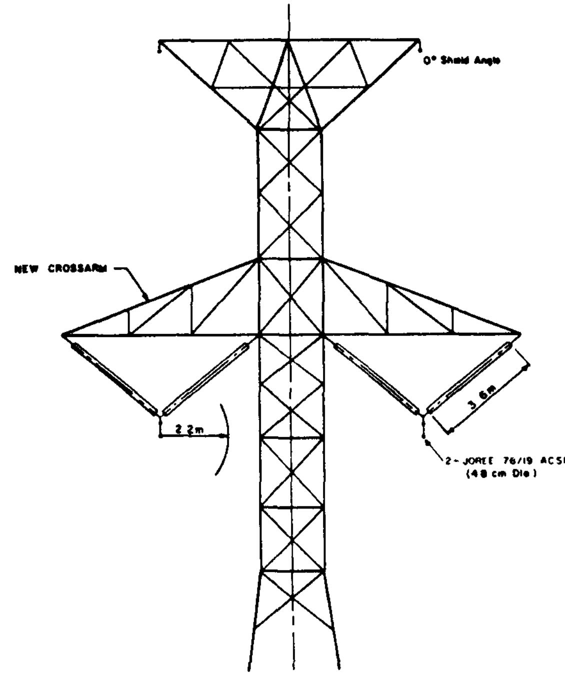
More practical is the upgrading of existing circuits to either higher voltage, double circuits, or to high voltage direct current. Such conversions can result in power increase factors of 2-6 in the same corridor.

HVDC transmission has seen a dramatic increase in the past two years. In fact between 1970 and 1983 four dc systems went operational in the U.S. Between 1983 and 1986 eight additional HVDC installations will be in service. By 1990 at least 2 more lines are planned. Canada will by that time add three more installations to its existing five terminals and lines. Why the sudden increase? Several reasons predominate:

- Available hydro power to supplant oil
- Asychronous interties
- Western load to east and west load centers
- Stable equipment costs
- Lower line construction costs
- Increased reliability through advanced technology



EXISTING 230 KV A.C.



MODIFIED TO ± 400KV BI-POLAR

CONVERSION OF EXISTING 230 KV
DOUBLE CIRCUIT AC TO BIPOLAR 400 KV DC

	ITEMS	EXISTING 230 KV A C DOUBLE CIRCUIT	NEW ±400 KV BI-POLAR	REMARKS
	ELECTRICAL CRITERIA			
1	Conductor Size (Diameter)	ACSR 76/19(4 8 cm Dia)	ACSR 76/19(4 8cm Dia.)	The D C line requires fewer conductors than the existing A C line
2	Conductor Bundle Number & Diameter	One Conductor	Two at 45 7cm Spacing	
3	Mid-Span Clearance To Ground	10.7m at 93°C	12 2m at 93°C	
4	Sag	12 6m at 93°C	12 6m at 93°C	
5	Ruling Spans	305 m	305 m	
6	Audible Noise (db(A))	5 at 18 3m		Distances are from center of line
7	RI & TVI (db)	35 at 18 3m		Distances are from center of line
8	Electric Field	2 1 Max 0 5 at 18 3m	9 0 Max	Distances are from center of line
9	Phase Spacing, Bundle To Bundle Center	8 2m Eqv	8 8m Eqv	
10	"V" String Air Gaps To The Side And Below	2 3m (I-String)	2 2m	
11	Insulation Length "V" String	2 6m (I-String)	3 6m	
12	Shield Angle (Max)	15°	0°	
13	Spacers / Dampers	None / None	None / As Req'd	
14	Line Losses (MW-HR / KM/YR)	40	230	Based on 1 SIL, 50% load factor resistance at 25°C for a c lines, equivalent for d.c. lines.
15	Power Transer (SIL= 1pu For A C) MW	260	1580	Power transfer multiple = 5 6
	STRUCTURAL COMMENT			
16	Suspension Towers			
	a. Anticipated Steel Modifications	Crossarm would be modified to accommodate additional loads. The remainder of the tower appears satisfactory. Remove top and bottom crossarms		
	b. Anticipated Hardware & Insulator Modifications	New yoke plates are needed for two bundle pole. Existing insulators might be used in a double I-String or new insulators of higher strength may be required		
	c. Anticipated Foundation Modifications	None anticipated		
17	Strain Towers			
	a. Anticipated Steel Modifications	Crossarm would be replaced to accommodate two bundle pole		
	b. Anticipated Hardware & Insulator Modifications	New hardware would be required for two bundle phase Existing insulators might be doubled for two bundle pole		
	c. Anticipated Foundation Modifications	None anticipated		

CONVERSION OF EXISTING 230 KV DOUBLE CIRCUIT AC TO BIPOLAR 400 KV DC
(continued)

The design and construction approaches utilized in HVDC terminals are similar to those employed in large HV substations, particularly in the outside ac and dc yards. This is true even though smoothing reactors, filters, and large reactive supplies are not applied in the same manner in ac switchyards.

The valve hall which contains the conversion equipment can be somewhat special although as the industry has moved to liquid cooled thyristors, the size and special pressurizing and clean air requirements have lessened.

One requirement which remains a critical construction problem is the necessity for a large ground electrode capable of carrying normal load current for several minutes in case of the necessity of operating in the monopolar mode for a short time. The soil and land requirements for such an electrode are quite exacting.

Probably the most exciting aspect of HVDC is in the system planning, pre-design studies, and control areas. The engineering and design aspects of this technology are finally working their way into the literature, and out of the manufacturers' closets, so to speak, where they were held captive when HVDC was considered only for specialty applications, such as long underwater crossings. It is likely that conversion of existing ac circuits will greatly increase because of the benefits which will accrue from the broader exposure of the technology to the industry.

It seems apparent that significant future advances in construction techniques will depend on whether there is a major increase in electrical load demand in the U.S. and Canada. Lowered oil prices and continued low load growth could completely stymy new equipment and construction creative processes. On the other hand, the special characteristics of HVDC, its adaptability to economical conversion of existing ac circuits, and the exposure of HVDC design and ac system interaction theories to a waiting industry may combine to expand this mode of transmission into a larger and more important role.

CASE HISTORY OF INDUSTRIAL PLANT STEAM SYSTEM LAYUP FOR DIRECT-FIRED GAS OPERATIONS

Glenn N. Stacy
Rogers Corporation

I wish to present you with the facts and statistics of an industrial plant steam system layup for direct-fired gas operations; and I also will tell you, in general terms, why and how it was done. Valid reasons existed in 1980 and 1981, for this project and even with the violently changing relative cost of oil and gas, our decision is still good today.

Our plant heat energy distribution system was steam. It had been steam historically. We thought in terms of steam being the best and most economical heat energy form.

In 1979, natural gas became available to us at a price substantially lower than #6 oil. We were able to utilize it as a boiler fuel with an investment recovered in three months time.

We also then had gas fuel on the premises which opened up new possibilities for gas-fired applications anywhere in the facility.

The major steam consumers in our plant are the paper dryers. We established that a substantial saving could be achieved by installing direct-fired gas burners to perform the function of the steam coils in the dryers.

Fuel price savings indicated that gas firing our largest dryer would pay for the installation in one years time so the project was implemented. The work was completely successful with a 50% energy saving plus substantial operating time saving and a greater temperature operating range.

Conversion work entailed a reasonably straight forward engineering application of line burners in tandem with steam coils in each zone, a gas train for each zone with temperature controls, safety controls, and combustion air supply.

The direct gas fired system essentially puts all the BTU of the gas into the dryer air stream. Gas fuel utilized in this manner is 50% less than the amount of gas fuel required in combustion in a boiler to produce steam for the dryer.

It is worthwhile to note that the gas firing installation in this dryer was made so that one mechanic could convert from gas to steam or vice versa in about two hours. Once it was established that the dryers could be direct-fired with gas - and should be - it became apparent that our steam system would be a burden.

The steam unit cost would escalate markedly because of the base load a steam system requires. In our situation, the base load hardly diminished when the dryer loads were taken off. The base steam load was larger than several users and would always be a significant part of the total steam produced. The objective to shut down the steam generators and accommodate all the heat energy requirements of the facility with the lowest cost heat energy become apparent.

Converting a second dryer to direct-fired gas was also an economic stand-alone project, but it was included in the overall project to "Discontinue Boiler Hour Use".

In physical detail, this dryer had one more zone than the largest dryer and none of the zones were configured the same so the application engineering was actually more difficult even though the equipment and system were the same. The gas supply line was already in place and this dryer was also set up for easy switching between gas and steam heating.

Gas distribution through a 400,000 square foot, single and multi-story manufacturing, R&D, and office facility on a 200,000 square foot base can be quite costly. Three beneficial conditions existed, however. First, is the fact that the steam and gas sources were close together at the boiler room. Secondly, the steam requirements in the facility had increased over the years and some loop systems or duplicate lines existed to many areas of the facility.

Thirdly, although the plant piping systems were not on any drawings in any overall, useful form, I was fully knowledgeable of them because of 20 years in plant maintenance and engineering.

The primary gas distribution was achieved by using one line of the steam loop. It was a relatively new steam line of very adequate size extending from the utility supply at the boiler house to the far end of the plant in the longest direction. A complete and adequate steam system distribution throughout the plant was maintained with another existing header and with a new easily installed 200 foot tie line between two building steam piping systems.

The remaining gas distribution network was achieved with two judiciously placed 3 inch branch lines 200 feet long and the necessary 2 inch and under feeder lines.

In the opposite direction from the boiler room, a different problem existed. We did not have a loop or parallel piping, but had one long supply header. Under this condition the header was modified to carry either steam or gas by a manual but simple pipe line change in the boiler room. At two stations out on the header, simple manual pipe line changes must be accomplished according to what is in the header to supply the appropriate steam feeder network or gas feeder network. Steam to gas, or the reverse, can be accomplished by four men in four hours.

Our entire gas distribution system is at the utility supply pressure of three pounds per square inch. The distribution system pipe sizes are then not large and costly, but a pressure regulator is required at each piece of equipment. The system was put in place at a moderate cost by using as much existing hung piping as practical. Had that not been possible, this phase of the project may have been so costly that the entire project may have been debated, delayed, and deleted.

Surveying our facility to accommodate all the existing and potential steam consumers with gas fuel developed a variety of requirements. Not unexpectedly, some consumers simply had to have steam. A small recirculating air convection dryer required steam heating because methylene chloride was being removed from a web. The recirculated air containing the methylene chloride when exposed to the gas flame temperature would produce hydrochloric acid and in short order deteriorate the metal surfaces of the dryer. A recovery unit removing methylene chloride from the exhaust air required steam to regenerate its resin bed. A recirculating air coater dryer removing volatiles from the coating operated nicely with a steam coil but the gas flame was not tolerable. A can dryer required low pressure steam to operate or it had to be replaced.

These steam requirements had to be met and since they were physically located somewhat together, a suitable vacant space was agreed upon for the installation of a small gas fired packaged commercial water tube boiler of 5 million BTUH input. A duplex packaged boiler feed system, an automatic water softner, a chemical feed system and a blowdown separator were necessary auxiliaries.

The water tube boiler was chosen because continuous operation was not anticipated and the quick heat up and quick response to load changes was desireable with reduced energy loss on start up and cool down. A 250# boiler was selected so 160# steam could be provided as had been done and so we could tie directly to the existing steam system.

In another area of the plant some distance removed, paper machine water was heated. The water contained enough paperstock so that it had to be agitated considerably to keep an even suspension of the fibers. The best method of heating the water was by sparging live steam into it. I could not develop a better method of doing it at an equal cost so a second small gas fired packaged commercial water tube boiler of 2 million BTUH input was purchased. There would be no condensate return to this boiler and we had an excellent soft water source for feedwater available so only a small chemical feed system was purchased as auxiliary equipment. A 15# boiler was selected expecting a 12# maximum steam pressure. No feedwater pump was required because our water supply was at 45 PSI.

Totally removed from these two systems, a couple prototype molding presses were steam heated. It was extremely desireable to have steam heat on one of them to be certain of duplicating customer equipment. We also had a steam coil in an oven nearby which dried volatile material at times. Total steam required in this area was perhaps 500# per hour and the operations might be 20-30 hours per week. For this load, an electric, 3 phase, 550 volt, electrode steam boiler, 835,000 BTUH output at 160 PSI was installed. A condensate return system, feedwater pump and control, and a conductivity control for the boiler water are necessary auxiliaries. The electrode boiler is a very safe and efficient boiler system occupying minimal space and free of most safety considerations inherent with fire boilers.

The requirement of continuing to supply steam throughout the facility to certain users rated as the #1 problem; but the #2 problem, space heating, had its very challenging aspects also. Space heaters must be vented and venting posed a problem when vents must be carried above the roof line because almost half our floor space is not directly under a roof.

I had real reservations about implementing the project until I found and visited a three story plant with gas fired space heaters and learned of power venting, which is the proper, easy, and economical method for venting space heaters.

Power venting is simply a small induced draft exhaust fan mounted on a space heater to pick up all the products of combustion and blow them out the vent line which may exit the building horizontally through an aperture in the nearest wall and be suitably terminated after a 12" length. These are certain easily met restrictions to prevent re-entry of the exhaust into the building.

The selection of the space heater was very significant and I was sold on the features of a new fully assembled unit heater that promised up to 20% annual savings in fuel costs, up to 45% reduction in vent system heat loss, lower installation costs, more useable heat per unit and was in accordance with all efficiency codes. Also all units were to have electronic, intermittent pilot ignition systems rather than a standing pilot.

If a space heater is to be located in a dirty of mildly corrosive atmosphere, an indoor, separated combustion unit heater is available which is designed to separate the combustion process from the room air. Combustion air and flue exhaust gases are piped directly to the outdoors. These unit heaters were used wherever the industrically common halogens from the many products containing chlorides might exist even though the unit is obviously more expensive than the standard models.

My method of determining the space heating units required in an area was first to identify the sizes and locations of the existing steam unit heaters. In a few instances, I also calculated heat loss and calculated heat requirement for specific areas. Generally, I had only to provide equivalent heating capacity properly mounted and from my own knowledge of actual conditions through many seasons and awareness of recent or upcoming equipment or building changes I added to or substracted from the existing steam heat. This was a good opportunity to upgrade the plant space heating system. To expedite installation, simple Honeywell T87F thermostats were used to control each heater. A more elaborate area or central control will undoubtedly be installed soon.

Associated with space heating is air makeup heating. One area had a 15,000 CFM steam heated air makeup unit, and I found that trying to install additional direct gas fired heating into this unit was at least as costly as installing a completely new direct gas fired unit. The air makeup requirements in two areas were met with two identical, 2-speed, 1-1/2 million BTUH direct gas fired units with modulating temperature control. The off condition and 2-speeds approximate most air makeup requirements so is energy effective. The direct gas fired units are most fuel efficient because nearly 100% of the fuel BTU is put into the air stream as compared to 80% in a heat exchange, vented unit. The air quality is basically unaffected.

Two small office complexes had individual HVAC systems with their heat from steam coils. Both installations had cramped ductwork at the unit outlet so gas heating was tough or impossible to install. In both cases it was possible to install electric resistance heat in the ducts with minor modifications and not add excessive electrical load. The heat cost increased threefold probably, but the dollar amount was not consequential.

Another fairly large office complex had a hydronic system of circulating hot or chilled water for environmental control. The system heating hot water was heated by a shell and tube steam heat exchanger while a second exchanger heated potable water. To discontinue steam useage the potable water was simply heated with a gas fired hot water heater and heating system hot water was provided by a 400,000 BTUH gas fired commercial boiler.

Another benefit was that a previously recommended energy saving measure was implemented with this project that might never have gotten done.

I could not get a small manufacturing activity out of a fairly large separated building in order to close up the building and discontinue all energy to it. Gas supply provisions were made, heating units were specified, but agreement was reached that these plans would be implemented. Before cold weather arrived it was found that the activity was removed and the building layed up according to recommendations.

Other interesting and challenging facets of shutting down the steam system were involved. Each had to be fully and properly resolved or it was the weak link in a chain which jeopardized the entire project.

A small recirculating air dryer was direct-fired with gas using an integral - blower burner - much like a residential gas burner. Although not a larger dollar savings, the fuel savings was at least 50%.

I attempted to provide electric radiant heat to a walk-in oven. A 30kw installation was insufficient and 45kw overheated the heater panels. I was using our own second hand units and probably misapplying them so I abandoned them for the same integral-blower burner just mentioned and a most satisfactory operation.

A room in which flammable vapors were present had to be heated and it had constant exhaust ventilation. The excess heat from the ceiling area of the adjoining space was blown into the room.

Layup of the central steam boilers, steam distribution system and condensate collection system to maintain all components in a condition so they could be returned to service in eight hours was the final physical objective. This was not done except for one boiler. It was cleaned on the firesides and watersides and filled with water. A 5 gpm pump providing circulation between the mud drum blowdown line and the continuous blowdown line in the steam header was installed with a feeder connection for adding catalyzed sulphate to scavenge oxygen. The remaining two boilers should be treated the same but they are older boilers and not really needed so they have been cleaned and left dry. The steam and condensate piping systems have been abandoned rather than layed up even though particular engineering attention and effort and dollars were expended to provide for gas fuel or steam fuel at every piece of equipment and system throughout the facility.

The gas fuel price increase has rekindled our interest in oil fuel at this plant and we now wish to make certain that our boilers are useable, that the steam distribution and condensate collection systems are useable and that steam coils, controls and so on are useable. We are now operating in our second winter on direct-fired gas so I feel confident that the steam systems can be activated with very little trouble and minor cost. To convince management that the steam generators and systems should be kept in a state of readiness is now an easy task.

We find the cost of gas in Eastern Connecticut to have risen 60% since the conversion project was implemented. The cost of oil has dropped 20% but actual operating costs of our facility on direct-fired gas is lower than utilizing the steam system and firing either gas or oil in the boilers. A fair statement of relative costs is that when the cost per BTU of fuel to the boilers is one half the cost of the BTU in gas fuel coming to our plant, the two modes of heat energy are equivalent. Under that condition some real factors relating to convenience, unit operations, projected production rates, phasing in or out of production operations, must be considered.

I believe that minimal cost and attention will keep both systems available to be used however and whenever appropriate and that the direct-fired gas system has been a most economical and worthwhile addition.

CRITERIA FOR COAL GASIFICATION PROCESS SELECTION

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ABSTRACT

At the present time a number of coal gasification and gas cleanup processes are in the process of being demonstrated or are already commercially available. In general, each gasifier has unique characteristics which make it more or less suitable for certain applications. Gas cleanup requirements are, in turn, set by the process and environmental constraints and by the gasifier selected.

This paper presents a number of criteria which can be used to help match an appropriate gasifier and gas cleanup system to reach the desired end product. Initially, general advantages and disadvantages of generic gasifier types are presented. Key factors to be considered in the selection of gasification and acid gas removal processes during a conceptual or preliminary design screening analyses are discussed. Finally, the following three specific gasification case studies are presented based on actual conceptual and preliminary designs performed by Gilbert/Commonwealth:

- Medium Btu gasification for industrial fuel applications.
- Medium Btu gasification for coproduction of electric power and methanol.
- Low and medium Btu gasification for utility combined cycle applications.

INTRODUCTION

Gasifiers can be classified as fixed bed, fluidized bed, or entrained bed based on the way the coal is reacted in the gasifier reactor vessel. Gasifiers can also be categorized as pressurized or atmospheric types, or air-blown or oxygen-blown types.

Fixed bed gasifiers offer the advantage of high over-all thermal efficiency with minimum heat loss due to the countercurrent movement of coal and product gas in the gasifer reactor vessel. The lower product gas exit temperature due to the countercurrent operation, however, results in the production of tars and phenols exiting the reactor with the product gas. Caking coals and coal fines can also be a problem for fixed bed gasifiers.

Fluid bed gasifiers offer the advantage of high coal throughput, efficient heat transfer and rapid approach to equilibrium for the product gas reactions. The fluid beds are less efficient than the fixed beds, but can accept a smaller coal size.

Entrained bed gasifiers offer the advantage of high carbon conversion, high product exit temperature which results in less tars and oils produced, low methane formation (more suitable for hydrogen production) and the ability to accept virtually any coal type. A lower H_2/CO ratio product gas produced with an entrained bed, however, requires more shift conversion for synthesis gas applications. The thermal efficiency is lower for an entrained bed than a fixed bed, and the operating conditions are more severe.

Listed in Table I are both commercially available and developmental gasifiers. "Commercially available" means that these gasifiers are used in industrial plants in the United States or overseas and can be purchased with some measure of performance guarantee.

The selection of an optimum gasification and associated gas cleanup process for a particular application is a multi-faceted problem. Capital and operating costs have traditionally been used as the main criteria for selection of a synfuel process. Other factors, however, such as gasification unit process efficiency, process simplicity, coal flexibility, load following capabilities and severity of material must also be considered before the final process selection is made.

Listed in Table II are some of the key factors which are generally reviewed during the selection of a gasification process for a particular application. Key factors which effect the selection of an acid gas removal system are listed in Table III.

TABLE I
COMMERCIAL AND DEVELOPMENTAL GASIFIERS

COMMERCIAL GASIFIERS

Fixed Bed	Fluidized Bed	Entrained
• Dry Lurgi	• Winkler	• GKT
• McDowell-Wellman		
• Wilputte		
• Riley-Morgan		
• Wellman-Incandescent		
• Stoic (Foster-Wheeler)		
• Woodall-Duckham		

DEVELOPMENTAL GASIFIERS

Fixed Bed	Fluidized Bed	Entrained
• Slagging Lurgi	• HT Winkler	• KBW
• METC	• Westinghouse	• Texaco
• KilnGas	• U-Gas	• CE
• GEGAS	• Hy Gas	• Shell/Koppers
	• Fast Fluidized Bed	• Dow
	• Exxon	• Bi Gas
		• SRT Hydrogasifier
		• Mountain Fuel Resource

TABLE II
KEY FACTORS AFFECTING GASIFIER SELECTION

- Proposed Plant Capacity
- Proposed Product Slate (low Btu gas, SNG, methanol, etc.)
- Time Frame of Proposed Plant and Associated Commercial Availability of Gasification Processes
- Capital and Operating Costs
- Plant Location
- Coal Feedstock Type (rank, ash fusion temperature, caking properties, sulfur content, etc.)
- Coal Feedstock Preparation Requirements (coal size and moisture content)
- Gasifier Efficiency and Carbon Conversion
- Gasifier Load Following Capabilities
- Product Gas Cooling Scheme and Associated Efficiency
- Gasifier Utility Consumption (oxidant, steam, BFW)
- Severity of Materials
- Simplicity of the Process

TABLE III
KEY FACTORS EFFECTING ACID GAS REMOVAL SELECTION

- Composition, Temperature, and Pressure of Feed Gas
- Environmental Restraints on Exit Product Gas
- Process End-Use Restraints on Exist Product Gas (selective H_2S removal, simultaneous H_2S and CO_2 removal)
- Ability to Remove or Tolerate Minor Gas Impurities, such as NH_3, HCN, COS, CS_2, SO_2, SO_3, Mercaptans, and Hydrocarbons or Tars.

To illustrate the rationale for selecting a gasification and gas cleanup system for a specific project, three case studies are presented for a number of desired end products. These case studies are based on conceptual and preliminary projects performed by Gilbert/Commonwealth.

CASE STUDY:
MEDIUM BTU GAS FOR INDUSTRIAL FUEL GAS APPLICATIONS

Recently, Gilbert/Commonwealth completed a preliminary design for a coal gasification plant for Philadelphia Gas Works. This project has been referred to as the Riverside Gasification Project. The proposed plant was designed to produce a medium Btu gas for use by industrial sources located within a five mile radius of the site. This gas will be distributed by a separate distribution system. The plant was designed to produce 20 x 10^9 Btu/day of fuel gas from 1000 tons per day of Pittsburgh No. 8 coal.

For the Riverside Plant, the use of second generation gasifier designs was avoided because of a certain degree of risk associated with units currently under development. It was, therefore, imperative that the process be selected from those systems which have been commercially proven and are guaranteed by the process manufacturer. In addition, oxygen-blown gasification units were preferred over air-blown units since a medium Btu gas would minimize retrofit costs to the end user compared to low Btu gas. Based on this initial criteria, the gasifiers selected for evaluation for use at the Riverside Plant were: an oxygen-blown, fixed bed gasifier - Lurgi; an atmospheric entrained bed gasifier - GKT; and a low pressure, fluidized bed gasifier - Winkler. A closer examination of these gasifiers led to the selection of the final system which was recommended for the Riverside Plant.

An evaluation of the process characteristics for each gasifier is shown in Table IV. Key factors include suitability for medium Btu gas production, load following capability, cost of product gas, coal flexibility, tar production, turndown capability, reliability, liscensor guarantee, capital requirements, phenol production, compression required, ash disposal and site acreage required. Based on this evaluation, either the Lurgi or the GKT process is preferred, although both processes are more capital intensive than the Winkler gasifier. Between the Lurgi and GKT process, the GKT shows a lower operating cost and is more flexible in terms of feed coal selection.

An important consideration in the process selection is the ability to gasify coals within a broad range of properties. The fixed bed gasifiers, because of their lower operating temperature, produce varying quantities of tars, phenols and ammonia. Effective removal of these byproducts requires additional investment and operating in-

TABLE IV
COMPARISON OF PROCESS CHARACTERISTICS

PROCESS	Suitability for MBG Production	Load Following	Cost of Gas	Coal Flexibility	Tar Production	Turndown	Reliability	Guarantee	Capital	Phenol Production	Compression Req'd.	Ash Disposal	Site Acreage Adequate	TOTALS +	TOTALS o	TOTALS –
Lurgi	+	+	+	o	–	+	+	+	o	o	+	o	+	8	4	1
GKT	+	+	+	+	+	o	+	+	o	+	o	+	+	10	3	0
Winkler	+	+	o	–	o	o	+	+	+	o	+	o	+	7	5	1

Key:

+ – no problem

o – could present a problem

– – definitely a problem

convenience. These by-products are produced as a function of the volatile components in the coal and increase with coals that are more reactive and more easily gasified. The GKT processes are capable of gasifying virtually any type of coal, with the minor exception of those with high ash fusion temperatures. The gasification temperature is sufficiently high to oxidize all of the volatile coal components, thereby eliminating the tar problem.

Another consideration which favors the GKT gasifi for the Riverside Plant is the 35 psig product gas batt limit pressure requirement. The high pressure operation the Lurgi gasifier is not particularly beneficial for the low pressure PGW application. Based on the evaluation of the three gasifiers, the GKT gasification process was selected for the Riverside Plant. A block flow diagram for the GKT process is shown in Figure 1.

For the product gas desulfurization facilities, a Stretford plant was chosen. A Stretford chemical-absorption system was selected over a physical absorption system for this application because of the low pressure operation and relatively small plant size.

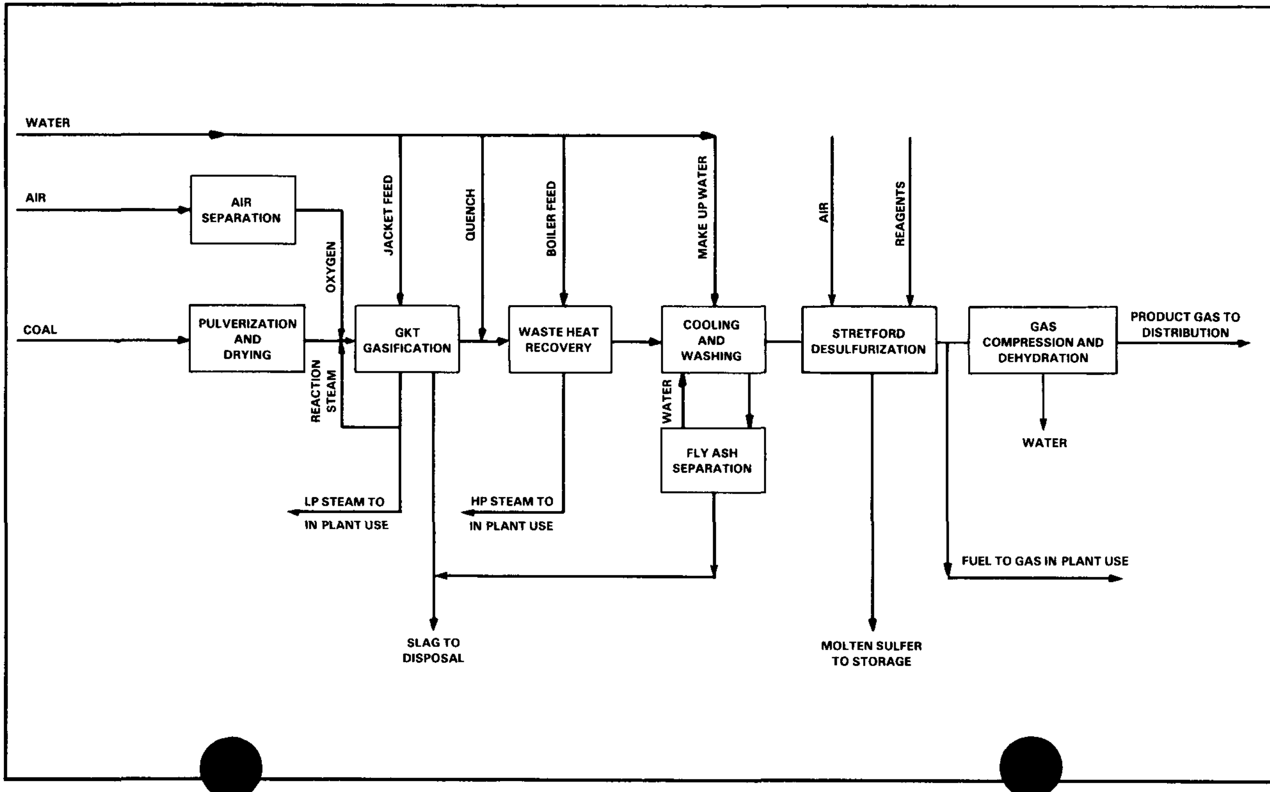
For this application, the GKT gasification product gas into the Stretford unit contained 0.90 mole percent H_2S and 0.09 percent carbonyl sulfide (COS) on a dry volume basis. The Stretford Plant removes almost all the H_2S from the product gas but COS is not removed. However, when burned the producer gas will emit only 350 ppmv SO_2 or 0.60 lb SO_2 per 10^6 Btu, the limit set by the City of Philadelphia.

The Stretford plant can be designed to produce either disposal filter cake or a marketable molten sulfur by-product. The selection depends on the plant capacity, environmental restrictions, by-product sulfur credit and the filter cake disposal costs. The molten sulfur configuration generates a purge liquor stream which requires either on-site treatment by reductive incineration or disposal by transportation to a hazardous waste treatment facility. Again the selection between the alternatives depends on the size of the plant and economic factors. An economic evaluation of the two options was performed for the Riverside Project. Based on the results, the molten sul alternative with on-site reductive incineration of purge liquor stream was selected.

CASE STUDY: MEDIUM BTU GASIFICATION FOR COPRODUCTION OF ELECTRIC POWER AND METHANOL

Electric utilities are particularly sensitive to increasing prices and uncertain supply of petroleum-based fuels. An example of this sensitivity is the Fuel Use Act which would prevent utilities from burning natural gas

FIGURE 1. MEDIUM BTU GAS FOR INDUSTRIAL APPLICATIONS (GKT GASIFICATION) BLOCK FLOW DIAGRAM



after 1989. Intermediate and peaking power operations are of greatest concern since these usually utilize oil or gas as fuel.

Gilbert/Commonwealth recently completed a study examining the coproduction of electric power and methanol from coal. The methanol would be used for peak shaving applications at other facilities. Two cases were evaluated in this study. Case 1 produced 350 MW of electric power and 119 million gallons/year of methanol and Case 2 produced 350 MW of electric power and 200 million gallons/year of methanol.

For the proposed facility the choice of the gasifier was the most important item in the process selection since, in many ways, it determined the selection of other equipment. Only commercially available or near-term (1985-1990) available gasifiers were considered. For this application, high throughput pressurized oxygen blown gasifiers were viewed as most appropriate. A low methane content was also considered advantageous as was a high hydrogen/carbon monoxide ratio since the stoichiometric H_2/CO_2 ratio required for methanol synthesis is 2.0.

Evaluation of gasification processes in terms of these criteria identified two suitable gasifiers for the process concept: the Texaco entrained bed and the Slagging Lurgi fixed bed gasifiers. Previous studies conducted by Gilbert/Commonwealth and data from existing literature were both used to compare the Texaco and Slagging Lurgi processes. The latter was selected because of lower capital investment and product costs, lower oxygen consumption, a dry coal feed system which leads to lower makeup process water requirements, and elimination of the need for stack gas scrubbing. The Slagging Lurgi gasifier has been operating successfully for over 3000 hours at Westfield, Scotland using American coals, and an 8 foot internal diameter gasifier is being offered with a commercial performance guarantee.

Presently available acid gas removal processes were reviewed. These processes can be classified into three categories: physical absorption, chemical absorption and direct conversion processes.

When selecting an acid gas removal process, the prime consideration is whether a physical or a chemical absorption system should be used. Both hydrogen sulfide and carbon dioxide are present in the medium Btu gas feed to the desulfurization unit; the chemical absorption processes, such as the hot carbonate and amine systems, were therefore eliminated on the basis of their nonselectivity between hydrogen sulfide and carbon dioxide.

Since the syngas may contain up to 0.04 percent COS, the Rectisol and Selexol physical absorption processes were initially selected. A tradeoff study was performed, considering operating pressures and acid gas concentrations as well as costs, ability to remove COS and carbon disulfide, commercial experience and stability of absorbents. The Rectisol process was selected because of the following advantages: use of only one solvent, methanol, to remove all impurities; production of methanol in the plant; twenty-five years of successful trouble-free operation at the SASOL installation in the Republic of South Africa, integrated with a Lurgi gasification plant; removal of COS; and low capital and operating costs.

The shift reaction has been used commercially to make various synthesis gas mixtures for the production of ammonia and methanol and chemicals by Fisher-Tropsch and oxo syntheses. Coal gas has been commercially shifted via a Fisher-Tropsch synthesis at SASOL.

There are two reactor types available for this shift reaction, fixed- and fluidized bed. The fixed bed adiabatic reactor design was selected because it has a lower investment cost, operates at pressures consistent with the gasifier, has a higher conversion efficiency and has been proven commercially at SASOL.

In screening the catalyst choices, the selection criteria included: capability for use over a wide temperature range; high activity in the presence of sulfur, phenol and other contaminants; high physical strength; retention of activity at the end of the regeneration cycle; and commercial acceptance. A cobalt-molybdenum catalyst manufactured by Girdler Chemical Co. has been selected.

The Claus process was selected for recovering sulfur from the separated acid gases. Since complete conversion of hydrogen sulfide to elemental sulfur is not possible with this process, additional treatment, such as by the SCOT process, is necessary to treat the tail gas from the Claus unit. The tail gas typically contains sulfur, expressed as equivalent sulfur dioxide concentration, of 10,000 ppm to 30,000 ppm. The SCOT process reduces this sulfur equivalent to a 200 ppm to 500 ppm level.

For the methanol synthesis, the commercially proven Lurgi low-pressure (750 psig) methanol synthesis process has been selected for integration with the overall system. The process produces a purer methanol product and has a lower investment and operating cost than many other systems. The advantages of the low-pressure Lurgi process include: use of turbine-driven centrifugal compressors; lower capital cost; lower operating costs; use of low pressure equipment in the synthesis loop; and lower maintenance cost.

The flow sheet for the Slagging Lurgi process is shown in Figure 2. Note that a portion of the gas after acid gas removal is fired in a combined cycle power plant. The balance is converted to methanol.

It should be mentioned that while this case was for utility use, many selection criteria would be the same for the industrial production of methanol or gasoline via the Mobil methanol-to-gasoline process.

CASE STUDY: LOW AND MEDIUM BTU GASIFICATION FOR UTILITY COMBINED CYCLE APPLICATIONS

One of Gilbert/Commonwealth's international clients was interested in developing a 1000 MWe base loaded combined cycle electric power generating plant which uses coal gasifiers to provide fuel gas. For this study, gasification processes which could be commercially available by 1990 were considered. Three gasifiers were evaluated: Combustion Engineering (C-E), Westinghouse and Texaco. Each process was evaluated in an oxygen-blown configuration, which produces a medium Btu gas. The C-E and Westinghouse processes were also evaluated in an air-blown configuration, which produces a low Btu gas.

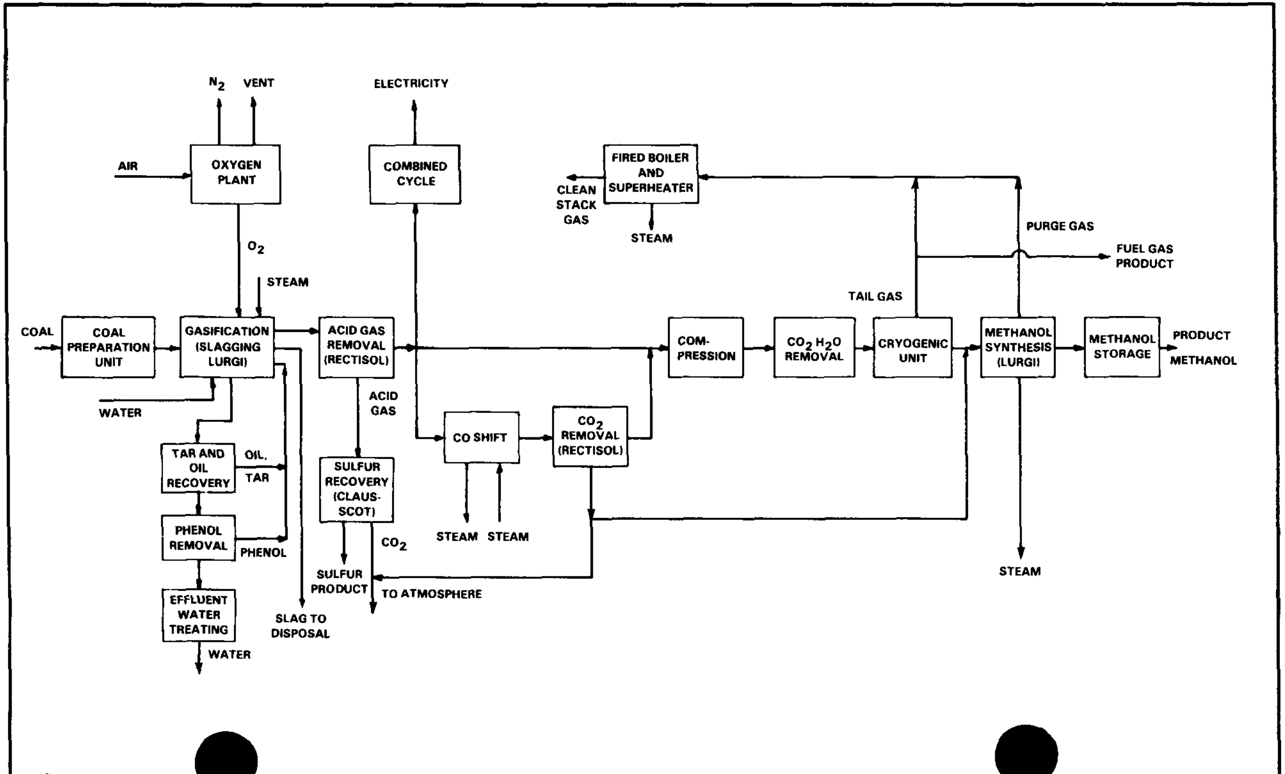
Figure 3 shows a simplified block flow diagram for a coal gasification combined cycle plant. The systems in the combined cycle plant include coal handling and preparation, gasification and raw gas cooling, desulfurization, fuel heating, gas turbine/generator, heat recovery steam generator (HRSG), steam turbine/generator, condenser and feedwater systems and cooling tower.

For the proposed plant, a generic Gulf coast location was selected and an Illinois No. 6 coal feedstock was chosen. The gas turbines evaluated in this study were selected by the client. Westinghouse W501D5 gas turbines were used with both the C-E and Westinghouse air-blown and oxygen-blown gasifiers, and the General Electric PG7111 gas turbines were used in conjunction with the Texaco oxygen-blown gasifiers.

The performance quotes in these studies were obtai from vendors for major pieces of equipment. The st cycle was integrated into the gasifier and raw gas coo systems in accordance with the guidelines set by each gasifier manufacturer. Gas turbine performance corresponded to a $2,192^{\circ}F$ combustor exit temperature rating, representing performance levels currently used in peaking duty gas turbines. Base load operation at that temperature rating can be expected in the mid-1980's.

The plants evaluated in these studies did not include operating or maintenance spares. The purpose in developing

FIGURE 2. MEDIUM BTU GAS FOR METHANOL/ELECTRIC POWER PRODUCTION (SLAGGING LURGI GASIFICATION) BLOCK FLOW DIAGRAM



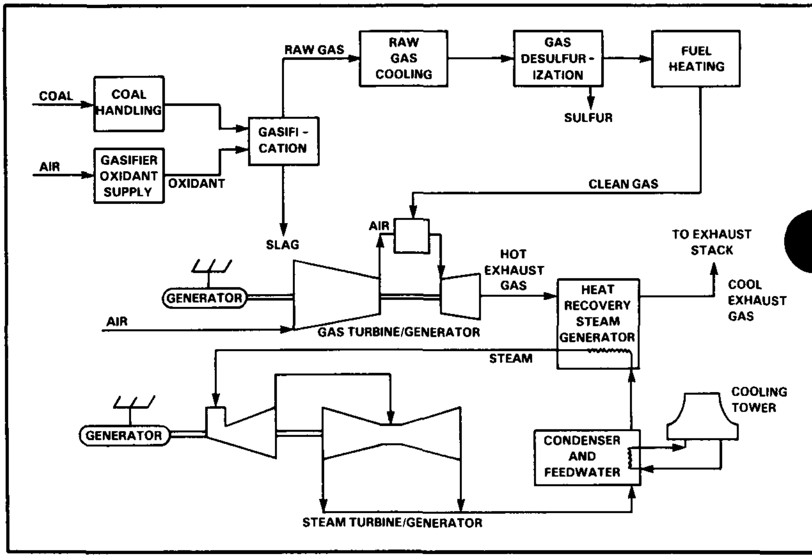


FIGURE 3. COAL GASIFICATION COMBINED CYCLE POWER PLANT BLOCK FLOW DIAGRAM

the levelized annual busbar costs was not to provide definitive costs for each of the systems, but rather to provide data which was helpful in comparing the systems to allow screening of alternatives for further evaluation.

The gasifiers evaluated in this study were second generation units and still under development. The C-E gasifiers were atmospheric pressure, entrained upflow units. These units incorporate water cooled thin refractory-lined walls which minimize heat losses and generate high pressure steam. The unit size is very large compared to other gasifiers, but still is smaller than the conventional boilers which they strongly resemble.

The Westinghouse gasifiers evaluated were pressurized fluidized bed units. Superheated steam injection along with the recycle of raw gas was used to control the temperature. The Westinghouse gasifier is an agglomerating bed type which depends upon low melting point eutectics in the coal char for ash removal. The Westinghouse air-blown gasifier requires significantly more units than the other cases. Each of these units has a thick refractory lining.

The Texaco gasifier evaluated was a pressurized entrained downflow unit. The gasifier is a thick refractory lined vessel. A coal/water slurry is fed with oxygen at the top. The water slurry provides cooling as well as a simple way to inject coal into the pressurized gasifier.

A radiant heat recovery section is located below the gasifier, followed by a convective cooler.

The C-E gasifiers were coupled with a Stretford chemical absorption system to remove hydrogen sulfide (H_2S) in the raw gas. A properly designed Stretford unit can remove essentially all the H_2S; however, it is ineffective (as mentioned earlier) in removing COS. Therefore, a COS hydrolysis unit was added upstream to the Stretford in order to meet the stringent environmental standards, of the country in question, of 50 ppmv of SO_2 with six percent oxygen in the flue gas. The Stretford units operate at atmospheric pressure, have relatively low power requirements and produce a clean, marketable sulfur product.

The Selexol physical absorption desulfurization system was selected for both the Westinghouse and Texaco cases. The stringent environmental standards of the country required that the Selexol unit remove a major portion of COS as well as H_2S. This removal was accomplished by operating the Selexol unit at a low solvent inlet temperature (60°F) which provided the required removal of both H_2S and COS. The Selexol system has a relatively low power requirement, good selectivity, good solubility of both H_2S and COS and a low solvent vapor pressure. A Claus unit and a Beavon-Stretford tail gas treatment unit were provided for sulfur production and emission control.

In evaluating this gasification process, the gasifier itself represents only a small portion of the total cost of a combined cycle plant. The type of gasifier selected, however, largely determines the overall conversion efficiency attainable. Clearly, the higher the gasifier efficiency, the higher is the overall conversion efficiency. Note, however, that cold gas efficiencies are particularly misleading in gauging gasifier effectiveness in combined cycle plants as the sensible heat in the offgas can normally be effectively recovered. Also, factors such as H_2/CO ratios and methane formation, which are important in synthesis and SNG processes, are not of consequence in electricity production.

Subjective factors which should be considered in choosing the optimum system include operational experience with the gasification systems. The C-E process has demonstrated operation only in the air-blown mode and requires a 25 to 1 scale-up to achieve the required commercial unit size considered in this study. The Westinghouse system has operated in both air-blown and oxygen-blown modes. Operational experience in commercial use will be greater than that of C-E since a Westinghouse gasifier at a 1,200 ton/day size will be delivered to the SASOL II Project in 1984. The Texaco gasifier will have the most operating experience in the combined cycle mode since a Texaco gasifier was used in the 100 MWe Cool Water Coal Gasification

TABLE V
CGCC PLANT PERFORMANCE COMPARISON

Gasifier	C-E	C-E	WH	WH	Texaco
Type	atm	atm	press	press	press
Gasifier Oxidant	air	oxygen	air	oxygen	oxygen
Clean Gas HHV,					
Btu/lb	1,523	5,089	2,086	6,507	5,616
Btu/scf	102	281	135	327	286
Cleanup	Strtfrd	Strtfrd	Selexol	Selexol	Selexol
Number of Trains	6	6	3	3	4
Gas Turbine	WH	WH	WH	WH	GE
Number of Gas Turbines	5	6	6	7	8
Coal Feed, MWe	2,728	2,711	2,955	2,986	2,866
Gas Turbine Output, MWe	577	657	614	749	693
Turboexpander Output, MWe	112	0	0	0	0
Steam Turbine Output, MWe	635	620	498	486	558
Plant Auxiliary Load, MW	326	246	108	168	205
Net Plant Output, MWe	998	1,031	1,002	1,067	1,046
Efficiency, Percent (HHV)	36.6	38.0	33.9	35.7	36.5
Heat Rate, Btu/kWh (HHV)	9,332	8,972	10,066	9,546	9,351
Total Capital Requirements, $/kW	1,197	1,363	1,410	1,370	1,580
Cost of Electricity, mills/kWh*	107.19	110.73	120.70	114.19	124.30

*Based on 70 percent capacity factor and $84.08/ton coal cost

Combined Cycle (CGCC) demonstration plant which is scheduled for startup in mid-1984.

Table V compares the estimated overall plant efficiencies, capital requirements and cost of electricity (COE) which have been predicted for the five CGCC systems considered in this study. The efficiencies range from a low of 33.9 percent for the air-blown Westinghouse gasifier plant to a high of 38.0 percent for the oxygen-blown C-E plant. These CGCC system efficiencies are for plants using deep sulfur removal. These efficiencies compare favorably with the 33 to 34 percent attainable in a modern coal fired plant with flue gas desulfurization which does not remove sulfur as efficiently as these CGCC plants.

For the lowest COE, the air-blown C-E plant appears to be superior, while the oxygen-blown C-E plant offers the highest efficiency. The oxygen-blown Westinghouse plant almost matches the efficiency of the air-blown C-E system, but with a COE that is estimated to be seven percent higher. The oxygen-blown Westinghouse gasifier appears to be superior to the air-blown Westinghouse unit, as both efficiency and COE are better for the oxygen-blown gasifier. The Texaco system has an efficiency rating about equal to the air-blown C-E system, but at a 16 percent higher COE due to its high capital investment requirements.

Based on the capital requirements, cost of electricity and the subjective factors mentioned earlier, the C-E air-blown and the Westinghouse oxygen-blown cases were recommended for further evaluation.

CONCLUSION

These case studies have been presented not to promote a particular gasification or acid gas cleanup process, but rather to demonstrate some of the selection criteria used in a conceptual or preliminary design screening analysis. A certain gasification process which is not attractive for a particular application may prove to be a viable alternative for another application. A final selection of a gasifier and acid gas removal process should be made after evaluating the client's requirements and criteria such as technical risk, gas cost and environmental concerns associated with each gasifier.

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NORTHERN ILLINOIS GAS CNG MARKETING PROGRAM: A GAS INDUSTRY CASE STUDY

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NORTHERN ILLINOIS GAS

Introduction to Northern Illinois Gas

Northern Illinois Gas (NI-Gas) is a public utility engaged in the purchase, storage, distribution and sale of natural gas. NI-Gas is the nation's fifth largest gas distribution company and the largest supplier of utility energy in Illinois. The Company service area covers some 17,000 square miles in the northern third of Illinois, generally outside Chicago. Included is service to nearly 1.5 million customers in 544 communities.

History of CNG

Methane, the principal element of natural gas, for powering internal combustion engines is nothing new. Use of the fuel occurred as early as 1801 in France, mostly as coal gas. A methane-fueled engine was demonstrated at the Paris International Exposition in 1867 and a liquefied methane fuel vehicle was shown at the 1905 Belgium World's Fair. Despite this early utilization, natural gas as a primary fuel did not become practical until the mid-20th century, giving way to the popularity of gasoline and diesel fuel.

Natural gas was, however, recognized in the early 1900's as a useful fuel for stationary engine applications for water pumping, power generation and oil field operations.

Shortages of liquid fuels prompted German, British and Italian technicians to investigate powering vehicles with town gas or other methane sources during World War II. The inability to store enough of the fuel on board was a problem. It wasn't until several years later that compression technology improved enough to make natural gas more practical.

The potential new market for natural gas and driving economy increased CNG interest in the late 1960's but the enthusiasm dwindled in the mid-1970's because of rising prices and gas supply problems. Now, however, adequate supply and a favorable price comparison with gasoline has made CNG an attractive alternative.

The Italians have 40 years of experience with methane-powered vehicles and currently have more than 250,000 in use. New Zealand has a goal of 150,000 CNG-powered vehicles by 1985. The United States has over 25,000 vehicles using CNG, with the number growing every day. Canada is offering subsidies and tax relief as incentives to convert vehicles.

The CNG System

The primary use of CNG in the United States is in vehicles converted for use with both CNG and gasoline, and, predominately in fleet applications.

CNG fuel tanks are usually installed in the trunk of a car or mounted under the chassis of a bus, truck or van. With gas compressed to 2,400 pounds per square inch (psi), a typical installation includes two, 340 standard cubic foot tanks in an auto. Using these tanks, a car typically averaging 15 miles per gallon of gasoline has a CNG range of 100 miles or more.

Other elements of a conversion system for CNG-gasoline operation include a high pressure fuel line, regulator system to reduce the pressure of the gas entering the carburetor, natural gas solenoid valve, gas-air mixer, gasoline solenoid valve, in-dash selector switch, fuel gauge, and an electronic spark advance.

The timing of the engine is changed electronically to optimize engine operation on the slower burning CNG fuel.

The CNG conversion enables the vehicle to operate on either CNG or gasoline. CNG, due to its lower cost, becomes the principal fuel with gasoline retained for back-up. The driver can change from gasoline to natural gas and vice versa while either in motion or stationary.

The clean burning qualities of natural gas result in lower emissions, extended exhaust system life, improved spark plug life and more miles between oil changes.

A conversion system for an auto costs about $1,400 per vehicle including installation and can be completed in a day by a qualified mechanic. Equipment can be transferred from one comparable vehicle to another for about $500.

The refueling system for CNG requires a compressor and filling taps. Two types of systems are used, slow-fill and fast-fill.

In the slow-fill system, a number of vehicles are connected to fueling lines, with compressors supplying CNG at a pressure up to 2,400 psi to the vehicle tanks. This is usually an overnight fill, about seven to eight hours, making it ideal for fleet systems with primary usage during daylight hours (school buses, delivery trucks, etc.).

In the fast-fill system, one or more cascades (a group of cylinders) are typically filled with CNG to 3,600 psi pressure. This allows the attendant to connect the filler hose to the vehicle, refilling the car's cylinders (fuel tanks) in minutes, comparable to conventional gasoline refueling.

Compressor stations cost on the average about $1,600 per fleet vehicle, depending on the type of system purchased and the amount of fast-fill capacity desired.

Safety

CNG is safer than either gasoline or propane, both in its inherent characteristics and its utilization system.

The vehicle cylinders used for CNG are made of high grade steel in compliance with U. S. Department of Transportation safety standards. They are, therefore, stronger than conventional gasoline tanks and can withstand more severe impacts. Because these cylinders are usually mounted securely to the vehicle in an interior or protected area outside, they are better protected from collision. The American Gas Association (A.G.A.), in a study to determine CNG safety, reports that of 1,360 accidents involving natural gas-fueled vehicles, more than 180 were rear-end collisions. No failures in the natural gas system were reported.

Cylinders mounted inside vehicles are vented to the outside. They are outfitted with safety valves that release gas to the atmosphere if unusually high pressures or heat develop. Because natural gas is lighter than air, it rises and dissipates rapidly into the atmosphere. Propane and gasoline are heavier than air and settle to the ground. Natural gas also has a much higher ignition temperature than gasoline, about 1,200 degrees Fahrenheit compared to 540 degrees Fahrenheit for gasoline.

The NI-Gas Fleet Program

Recognizing that CNG was gaining strength as a transportation fuel, NI-Gas began an active program to convert its fleet of 1,600 motor vehicles in early 1980. The gasoline shortages of the early 1970's, along with the dramatic potential fuel savings, stressed the need for an alternate source of fleet fuel.

NI-Gas currently operates about 175 of its vehicles on CNG. Included are passenger cars, light trucks and vans. The conversion program calls for nearly 600 CNG powered vehicles to be operational Companywide by the end of 1983.

The CNG Market Potential

The natural gas supply picture made a dramatic change in the early 1980's. The shortage years of the early 1970's were gone. NI-Gas once again was able to pursue new markets for natural gas.

The search has been a difficult one. A depressed economy has hampered the effort. In spite of a sluggish marketplace, CNG appeared to be a bright spot representing an opportunity to sell gas in a non-traditional market, transportation.

Recognizing the advantages to power its own fleet with natural gas, NI-Gas Marketing in early 1981 began exploring the idea of encouraging customers to convert. Even though the Company, at the time, had limited experience with its own fleet, it appeared that the concept of fueling motor vehicles with natural gas was sound and could be marketed. In spite of the high initial investment, the significant potential fuel cost savings would generate cash flows sufficient for an economically attractive return for the customer. And, with economics the principal consideration there was little doubt that CNG at the equivalent cost of about $.55 a gallon gasoline would receive customer acceptance. (Economics of Conversion Table). The residential, commercial and industrial accounts all appeared to have potential for CNG usage. The residential field was ruled out initially, however, because of economics and potential technical and safety considerations.

Economics of Conversion Table

Typical Example:

Cost of conversion and refueling system per vehicle		$3,000
Cost of gasoline		$1.20/gallon
CNG cost equivalent		$.55/gallon
Based on 24,000 miles per year driven and 12 miles per gallon mileage rate		2,000 gal/yr
A. Cost of 2,000 gallons of gasoline at $1.20/gal	=	$2,400/yr
B. Cost of CNG - 2,000 gallon equivalent at $.55/gal	=	$1,100/yr
Savings	=	$1,300/yr
C. Simple payback $\frac{\$3,000/\text{yr initial cost}}{\$1,300/\text{yr savings}}$	=	2.3 years

The commercial and industrial field, on the other hand, was given a closer look. Fleet operations with 10 or more vehicles appeared to be the market audience which would be best able to economically justify CNG. Operators of commercial and industrial motor vehicle fleets represented customers with personnel who could be trained to install, operate and maintain CNG equipment.

The high annual mileage and resulting fuel usage makes the commercial fleet vehicle the most attractive CNG user. The average fleet vehicle is driven 24,000 miles per year. Based on a mileage rate of 12 miles per gallon, the potential CNG usage is 2,000 therms assuming one therm of gas (100,000 Btu) is equivalent to one gallon of gasoline. At that rate, a 30 vehicle fleet has the potential of using 60,000 therms of gas per year, the equivalent of about 37 NI-Gas residential customers or two fast food drive-in accounts.

The NI-Gas service area has more than 1,400 accounts with commercial fleets of ten or more vehicles. The total vehicle count of fleet vehicles is nearly 170,000. The actual conversion potential is estimated to be 42,000. Included in the figure are passenger cars, vans, light and heavy duty trucks and buses.

Some of the principal business sectors which fall into this category are:

Auto Rentals
Bakeries
Bottlers
Communications
Dairies

Laundries/Cleaners
Law Enforcement
Local Transits
Local Trucking
Municipalities
Postal and Parcel Deliveries
Repair Services
Schools and School Bus Contractors
Taxi Fleets
Utilities

The NI-Gas CNG Fleet Marketing Promotion Program

A marketing emphasis on fleets was initiated through a cooperative promotion with CNG equipment suppliers. Guidelines were set forth and the program was designed using the following criteria:

1. Provide a reasonable return on the investment for the NI-Gas customer.

2. Suppliers have established channels of distribution within NI-Gas' service area for product distribution and service.

3. The suppliers product be reliable, proven and covered by warranty.

4. The suppliers or their representatives are qualified and reputable installation contractors.

5. Avoid any unreasonable degree of liability associated with NI-Gas' entry into such a program either on behalf of NI-Gas or the customer.

The Coordinator of CNG Marketing administers the promotion program. The program is promoted initially through a direct mailer to the customer fleet manager or the energy decision-maker. The mailer consists of an attention-getting letter. A reply card is included for the customer to return indicating an interest in CNG for his fleet operation.

The Marketing Department screens and records all replies. They are subsequently referred to the appropriate NI-Gas Division Sales office for follow-up. The commercial/industrial sales representative assigned to CNG sales contacts the customer and makes a field call to review the NI-Gas CNG program. The CNG sales representative prepares a gasoline cost comparison and promotes CNG for the customer's fleet. The CNG information sheet is completed in detail with the customer and returned to the Marketing Department. Marketing then forwards the information sheet to all program equipment suppliers.

The suppliers prepare a complete equipment proposal.

When the proposal is completed, NI-Gas Marketing coordinates a customer meeting for the presentation. The Division CNG sales representative, and in certain cases, the Coordinator of CNG Marketing, accompanies the supplier and assists in the equipment proposal presentation to the customer. The Division CNG sales representative follows the job prospect until the customer has made a decision on the proposal.

In addition, Division Sales personnel further support the program in their daily contacts with commercial and industrial customers. The Marketing Department supplies Division/Area Sales offices with lists of accounts which will include prospects for CNG use in fleets.

To further support the program, Marketing supplies sales personnel with brochure handouts and other material for prospective customers. Training sessions are held for Sales personnel to prepare and update them for their contacts with customers.

Customer CNG seminars and presentations are held and CNG vehicle displays included.

The Coordinator of CNG Marketing provides technical assistance, support and training for Division Sales personnel. The Coordinator of CNG Marketing is also responsible for contacts with firms which have fleets on a multi-division or national level.

Sales contests provide recognition for Division/Area Sales teams which produce the greatest sales results under the program.

The Suppliers

The program requires that suppliers be nationally and highly qualified organizations.

The program is open to all suppliers who can meet the qualifications set forth in the program.

NI-Gas Marketing collects all customer replies, and referrals are made directly to all suppliers.

It is the responsibility of the supplier to promote his equipment, make the sale and handle all billing. The supplier handles all arrangements for the delivery of equipment and installation, if needed.

The Goals

CNG Fleet Sales
Cumulative

Year	No. of Fleets	No. of Vehicles(1)	Sales "M" Therms (2)
1	10	300	360
2	25	750	1,500
3	45	1,350	2,700
4	65	1,950	3,900
5	85	2,550	5,100

(1) Number of vehicles based on NI-Gas area fleet surveys.

(2) Annual therm sales per vehicle estimated at 1,250 for passenger cars and up to 4,500 for commercial vehicles. The average for all sectors is 2,000 therms per year. (Based on 24,000 miles per year average and 12 miles per gallon equivalent.)

The Results

Following the kick-off of the NI-Gas CNG promotion on October 1, 1981 the program has produced the following:

Mailings (some repeats)	1,600
Mailing Replies	
Municipalities	90
School Bus Fleets	105
Miscellaneous: Bakeries, Laundries, Delivery	75
TOTAL	270
Fleet Surveys	125
Supplier Proposals	104
Sales	
Fleets	10
Vehicle Conversions	256

The total CNG fleet market currently served by NI-Gas:

Fleets	12
Vehicles	314

Conclusions

Considerable interest in CNG has been experienced since the program began in the fall of 1981.

The initial goal of ten fleet conversions has been met and activity in the past 14 months makes us optimistic. With the prospect of a strong gas supply future, a favorable competitive fuel cost position and improved technology, CNG should make substantial inroads into the transportation market.

With approximately 7 million fleet vehicles nationwide, and a growing number of conversions, greater CNG u would help ease U.S. dependence on foreign oil.

Public refueling for the home owner may depend on incentives, perhaps similar to tax and conversion subsidies offered in Canada. Auto manufacturers commitment to CNG for new vehicles also holds great promise.

As we approach 2000 and beyond, the use of CNG as a major transportation fuel is a promising alternative.

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FORD'S CNG VEHICLE RESEARCH

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INTRODUCTION

Several factors have contributed to a renewal of interest in natural gas (mostly methane) as a transportation fuel. In the late '60's, and early '70s, there was a flurry of activity with this fuel because it offered the potential of being able to meet emission standards more easily than gasoline. Gaseous fuels do not incur maldistribution problems as easily, methane has a lean burn capability, and it has a somewhat lower flame temperature, resulting in lower NOx. This is offset some, however, by a slower burn rate which tends to increase NOx formation. It also has low levels of soot formation, and is fairly non-reactive in the atmosphere. The latter attribute has been recognized by the California Air Resources Board, which has put a non-methane hydrocarbon standard in place for vehicle emissions. This characteristic also makes it difficult to reduce emission levels with the use of a catalytic converter, however.

Natural gas was in short supply during the Oil Embargo of 1973. This, combined with the new technology for emission control of gasoline-fueled vehicles precluded any further interest in natural gas as an alternative fuel. Today that picture, and incentives, are quite different.

Partial decontrol of natural gas prices, and huge increases in crude oil prices, resulted in the discovery of several significant gas fields throughout the world, including our neighbors, Canada and Mexico. High energy prices also have resulted in large cut-backs in natural gas use through improved efficiency devices and other conservation techniques. Hence, there are presently abundant supplies of natural gas at attractive prices relative to gasoline, making it a near-term alternative for use in transportation vehicles. Therefore, beginning in 1980, several natural gas vehicles have been built as part of the Ford Alternative Fuel Demonstration Fleet in order to better understand the benefits and disbenefits of such vehicles.

NATURAL GAS STORAGE SYSTEMS

Operation on natural gas offers a substantial cost advantage; without this it would be difficult to justify coping with all of the disadvantages and complexities of the system. Two basic methods of fuel storage are used: compressed gas (CNG) and liquefied gas (LNG). The energy density on a volume basis of the compressed gas is low, even at high pressures, compared to other fuels, making limited vehicle range one of the disadvantages of CNG operation. Achieving adequate range is somewhat easier with LNG, but this requires a cryogenic storage tank in order to keep the fuel at -260^{o}F. Since it is not possible to completely eliminate heat transfer, some warming and pressure build-up occurs, requiring periodic venting of the gas unless the gas pressure is adequately limited through consumption of the fuel by the engine. This makes prolonged, unattended storage of the vehicle in an enclosed space a potential fire hazard owing to the accumulation of automatically vented gas, unless the enclosure in turn is well-ventilated. Also, refueling of an LNG vehicle must be handled by highly trained personnel because of the danger of severe tissue damage at these temperatures. The liquefaction storage/refueling facility is expensive and probably can only be justified by a large fleet operator with a vehicle range requirement greater than that achievable with CNG.

Another possible option for fuel storage is to increase the energy density with the use of a suitable sorbent in the cylinder. Research at Ford has shown tha activated carbon has greater potential than zeolites (1). Further evaluation of this storage concept is reported elsewhere (2).

FORD'S NATURAL GAS VEHICLES

Since a public distribution system for refueling natural gas vehicles does not exist presently, the first CNG demonstration vehicle built at Ford research was dual-fuel; i.e., it retained the capability to operate on gasoline, as well as CNG. The vehicle was a 1979 4-door Zephyr sedan, with an automatic transmission. The engine was a 3.3-liter, in-line 6-cylinder configuration. Two high pressure (2400 psi) steel tanks were fitted in the trunk giving the vehicle a range of almost 90 miles on natural gas. The gasoline energy equivalent fuel economy on CNG was about 14.5 mpg in actual on-the-highway driving.

With two tanks in the trunk there was virtually no trunk space remaining. The weight penalty was 300 pounds, requiring installation of air shocks on the rear of the vehicle in order to compensate for this added weight. Merely leveling the vehicle does not really address the inherent handling problems introduced by this kind of change in weight distribution, however. The trunk was sealed off from the passenger compartment, but a methane gas detector was installed in the driver's compartment and several vents added to the trunk as additional precautionary measures.

The gaseous fuel mixer required an off-set installation in order to maintain the conventional hood-line. Since then, however, several fuel mixers have been designed to be installed in the air cleaner. No internal changes were made to the engine, so there was a loss in power when operating on natural gas because of the reduction in volumetric efficiency inherent with operation on any gaseous fuel. The dual-fuel system also suffered in performance when making the transition to natural gas from operation on gasoline. After shut-off of the gasoline flow, one had to allow the gasoline carburetor bowl to empty of fuel before switching to natural gas operation. For obvious safety reasons, it was best if this was done in a parked position at idle.

In general, the overall performance of the dual-fuel CNG vehicle was considered unsatisfactory.

In recognition of the more favorable range one could attain, the second natural gas vehicle utilized the LNG storage concept, but eliminated the option for gasoline operation. The cryogenic fuel tank utilized had a vent period of eight days at 80°F which was a major improvement over what had been available previously (only two or three days). The tank is designed like a giant thermos bottle; there is a tank within a tank, with a vacuum in between. The inner tank is suspended on fiberglas rods in order to minimize heat transfer. This particular tank has a capacity of 18 gallons, giving the vehicle a range of almost 400 miles, based on a gasoline equivalent fuel economy of about 22 mpg on the metro-highway driving cycle (average of 18 tests), providing no fuel was lost due to venting. The vehicle did not have any emission control equipment, however, and consequently did not meet exhaust emission standards. The NOx emissions were brought down to 1 gm/mile with a rich A/F ratio and 20^{o} advance on the ignition timing, but the CO was then over 50 gm/mi. The HC did not vary much over these 18 tests; it ranged from 1.3 to 2.0 gm/mi. This was a total hydrocarbon measurement. The percentage that was methane was not measured.

Even though this was a dedicated vehicle, because of the complexities of the cryogenic tank and the refueling procedure, the tank was placed in the trunk for easier access. The system added about 80 pounds to the weight of the vehicle.

The LNG vehicle was a 1980 Zephyr 2-door sedan with automatic transmission fitted with a 2.3-liter engine (4-cylinder). The compression ratio was increased to 14:1 with a piston change, taking advantage of the high octane number of methane (130 RON). The induction system was also modified for increased charge intake. The changes included the intake port and intake valve design, as well as a redesigned intake manifold. The camshaft was changed for improved low speed torque.

Because the dual-fuel CNG vehicle described previously was considered unsatisfactory, the third vehicle was a dedicated and optimized CNG vehicle, and in fact identical to the LNG vehicle except for method of fuel storage. In this case the gasoline tank was removed and five lightweight, high pressure (2500 psi) tanks were installed. Three tanks were under the vehicle and two were in the trunk, leaving about 60% of the trunk space usable. All five tanks were manifolded together with refueling through the normal access door.

The technology for these tanks is a spin-off from the space program. They are made from spun aluminum, wrapped with Kevlar (a composite) and have a burst pressure of 10,000 psi. The tanks weigh 28.5 pounds each, with a volume just under one cubic foot at ambient pressure. An equivalent capacity steel tank weighs over 100 pounds. Even with these five tanks, however, the vehicle range was only slightly better than 200 miles.

The fourth and fifth CNG vehicles in the demonstration fleet were a joint project between powertrain research and the design center. A 2-seater CNG commuter car was derived from the EXP/LN-7 vehicle. Two vehicles were built with identical powertrains. One is an LN-7 while the other has been named the AFV (Alternate Fuel Vehicle). This AFV concept car has a redesigned body with a drag coefficient even lower than the LN-7 (0.32 vs. 0.35). The floor pan of the vehicle was designed to accommodate three CNG tanks outside of the body cavity of the vehicle. Again, lightweight aluminum, high pressure tanks were utilized.

Fuel capacity is 4.3 cubic feet at ambient pressure; a storage pressure of 2500 psi gives the vehicle a range of about 200 miles.

Numerous changes were made to the 1.6-liter, 4-cyl. CVH engine in order to upgrade the performance on CNG to at least match that of its gasoline counterpart. This goal was actually exceeded, with a 0 to 60 mph acceleration time of 12 seconds in spite of an added weight of 100 pounds. The engine changes included an increase in compression ratio to 13.6:1, a camshaft with improved low speed torque, the high performance European cylinder head and a modified exhaust system to relieve back pressure. A close-ratio, five-speed gear box (manual shift) was added as well.

The AFV was on display at the Knoxville World's Fair while the LN-7 has been used for development work at research.

The fact remains, however, that at present there are no public service stations in the U.S. at which one can refuel natural gas vehicles. One alternative may be utilization of a small compressor at home using the residential gas supply. Prototype compressors have been under evaluation at Ford Research (2). Two open issues remain: initial cost of the compressor, and refueling in an enclosed space such as the residential garage. If it were a quick fill (5 to 10 minutes) it could be done outside, but since it will require five to six hours for refueling, in the winter in cold climates it would be preferable to have the vehicle inside the garage for overnight filling.

The most recent prototype CNG vehicle under test is a Ford Ranger truck with automatic transmission fitted with a 2.3-liter engine optimized for CNG, using basically the same techniques learned previously. In this case the compression ratio has been reduced to 13:1 because the previous 14:1 used in this engine appeared to be actually causing a loss in performance due to "choking".

The truck was baseline tested on gasoline, as received. The metro/highway fuel economy measured 22.7 mpg. After modification for CNG, but without EGR (exhaust gas recirculation), the fuel economy (gasoline equivalent) was [illegible].5. The initial ignition timing was 40^{o}BTDC, however, resulting in unacceptable NOx emissions. With the addition of EGR, NOx emissions were reduced from 9.8 gm/mi. to 2.3 gm/mi., but obviously additional work remains to be done. There was also some loss in fuel economy with EGR (20.3 mpg for metro/highway), but further refinements in the calibration are expected to improve this.

The tank packaging on the Ranger is underneath the vehicle between the main frame rails. Three light-weight aluminum tanks give the vehicle a range of 145 miles. An optional tank package, using two more tanks stacked behind the cab in the pick-up bed, would provide an extended range of 275 miles. The base package adds about 30 pounds to the weight of the vehicle.

CONCLUSIONS

Vehicle operation utilizing natural gas as a fuel offers substantial cost savings. Because public refueling stations do not exist at present in the U.S., natural gas operation is probably confined to the fleet operator, although the home refueling option utilizing residential gas is under study. Based on Ford's experience to date with CNG vehicles, it has been concluded that single fuel vehicles, optimized for CNG operation, provide better fuel efficiency and performance than dual-fuel vehicles, with acceptable range for most fleet operations.

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FUEL METHANOL ADDITIVES: ISSUES AND CONCERNS

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INTRODUCTION AND BACKGROUND

Consideration of the various alternatives to petroleum-derived fuels for transportation vehicles has led to the conclusion that methanol has the best potential for large-scale, long-term replacement of gasoline and diesel fuel in the United States. This country has abundant coal reserves from which methanol can be produced with relatively good efficiency using known technology. The transition resource, however, will probably be remote natural gas fields.

The same basic technology is used for methanol-powered and gasoline-powered vehicles. Some material changes are required since methanol has different physicochemical properties from gasoline. The Brazil experience, using ethanol fuel, validates the feasibility of alcohol-powered vehicles. Furthermore, extensive fleet tests on methanol-powered vehicles in the United States assure us that all potential problems appear solvable (1).

The State of California has become the leader in the U.S. for programs and incentives to launch methanol-fueled vehicles. Ford has had a 40 car methanol fleet in operation in Los Angeles County since June 1981 as part of the California Energy Commission programs (2). More recently, we have been identified as the successful bidders for a follow-on California fleet of approximately 600 vehicles. These vehicles will be built on a Ford assembly line, with delivery anticipated in June, 1983.

Coldstart is the most obvious problem associated with an alcohol-fueled vehicle. In Brazil, this problem is resolved via a secondary fuel, gasoline. Others have used propane (3). Ford has explored heaters and electric vaporizers as coldstart aids (4). These devices are technically feasible, but expensive. As a result of these studies, it was concluded that addition of a high volatility cofuel to methanol was a better way to produce coldstart capability. At the same time, cofuels also address other methanol issues.

For this reason, development work on methanol-fueled vehicles has been complimented by research on optimum fuel methanol composition. Attention has been focused on six concerns identified by Keller (5):

(1) Difficulty in coldstarting a methanol engine at temperatures below 10°C (50°F);

(2) Broad flammability limits of methanol vapor, making the air space about the liquid in the fuel tank potentially ignitable;

(3) Low flame luminosity, making burning methanol difficult to see;

(4) The corrosive nature of methanol which prohibits use of certain materials;

(5) Potential for misidentification and ingestion;

(6) Lack of lubricity and poor compatibility between methanol and most lubricants.

As noted below, many of these issues can be resolved by cofuel addition to methanol. Other issues require control of fuel methanol contamination. For example, residual chlorinated solvents, used in fuel drum cleaning, have been linked to excessive engine wear (6). Obviously, contamination represents an insiduous, open-ended problem since one must specify materials that cannot be tolerated in fuel methanol.

Table I lists the fuel specifications <u>currently planned</u> for the 600 car California fleet. This specification is intended for temperate climates; modifications would be required for colder locations. It should be emphasized at this specification is based on data available on February

14, 1983, and is subject to modification as more research and field results become available.

TABLE I

Fuel Methanol Specification
for 800 Car Build
(as of February 14, 1983)

Component	Specification	Use/Comments
Unleaded Gasoline*	9-11%	a) Odorant b) Coldstart aid c) Flame Luminosity d) Change vapor phase flammability
Water	<0.5%	Anhydrous methanol is an impossibility
Total Chlorine (organic + inorganic)	<0.001%	Severe engine wear linked to residual chlorinated solvents
Acidity	<0.003%	
Pb	<0.003 gm/l	
S	<0.01%	
P	<0.001 gm/l	
Filterability	<0.1 gm/liter	
Distillation Residue	<0.5%	
Methanol	Balance (88% minimum)	

Final fuel to have 6-9 Reid vapor pressure.

*Winter grade gasoline (11-13 RVP) suggested.

FUEL METHANOL: THE NEED FOR ADDITIVES

Human ingestion is the ultimate toxicological problem associated with methanol. Clearly, some denaturant must be used to render the fuel extremely unpleasant. We concur with Keller's judgment that addition of gasoline, or other hydrocarbons, probably serves this purpose(5). Neat methanol has a mild pleasant odor, whereas the odor of methanol/hydrocarbon is similar to that of gasoline. This provides an external warning. It is also suggested that these blends be named as "fuel methanol", and that such labels as "wood alcohol" or "methyl alcohol" should be scrupulously avoided because the lay person identifies the word alcohol with ethanol (ethyl alcohol). Ethanol is potable; methanol is not.

Excessive engine wear rates have been reported with some methanol vehicles. Attack of metals like aluminum, zinc and magnesium is well known. There is some empirical data relating excessive wear to fuel acidity and to fuel contamination by organic solvents containing chlorine (6). Our fuel specifications reflect this, although the phenomena producing high wear are not well understood. Anti-wear/anti-corrosion fuel additives would be extremely useful. To date, those examined at Ford have been metal specific. Obviously, something with broader coverage would be more desirable.

These concerns might be resolved by (a) quality control of fuel supply or (b) addition of small amounts of fuel additives (less than 1%) to methanol. Other issues appear to require higher cofuel concentrations. For example, improvement in front-end volatility, even in mild environments, requires 5 to 10% additive, depending on the cofuel used. The remainder of this paper discusses recent studies on these subjects. Keller provides a good discussion of earlier work (5).

1. Luminosity of Burning Methanol

In contrast to most liquid fuels, methanol burns with a blue flame that is almost invisible, especially in daylight. The luminosity of burning fuel is related to the formation of submicroscopic soot particles during the combustion process. Once formed, the particles are heated by the flame and subsequently emit grey-body radiation at visible light wavelengths. These minute soot particles are not formed during methanol combustion; consequently, methanol flame radiation occurs primarily at infrared wavelengths (invisible to humans).

We measured the luminosity (visible light radiation) of various burning liquid fuels (Table II). Similar data were obtained earlier by Coward and Woodhead (7). It is noteworthy that gasoline, ethanol and methanol have a 3000:100:1 luminosity ratio while burning. We experimented with cofuel addition to increase the luminosity of methanol fires. There is no accepted standard for a "visible fire", so the luminosity of burning ethanol was adopted as an objective for this work. Most hydrocarbons function as methanol fire luminosity-enhancers, but substantial concentrations (i.e., greater than 10%) are required with many of the cofuels tested to date. Also, selective distillation from the burning liquids can be critical. In particular, low boiling hydrocarbons used as coldstart additives readily distill in preference to methanol from burning liquids. This results in fires whose high initial luminosity decreases with time as the cofuel is lost and the residual liquid becomes enriched in methanol.

A motion picture, illustrating methanol luminosity effects, has been made. Burning 10% gasoline in methanol can be seen to have a luminosity equal to that of burning pure ethanol. It also exhibits minimal distillation effects (unlike isopentane which is lost quite rapidly).

TABLE II

RELATIVE RADIATION CHARACTERISTICS OF VARIOUS POOL FIRES

	Relative Luminosity	
	Coward & Woodhead[(a)]	Present Study
i-Octane	1.0	1.0 (defined)
Heptane	.71	0.95
i-Pentane	--	0.6
Cyclohexane	.83	0.71
Toluene	.07	0.70
Benzene	.07	0.22
Acetone	.13	0.25
Methyl Ethyl Ketone	.16	0.18
Ethyl Acetate	.08	.04
1-Octanol	--	0.06
1-Butanol	.21	0.17
2-Methylpropanol	.34	0.3
2-Propanol	--	0.19
1-Propanol	.09	0.06
Ethanol	<.01	0.03
Methanol	<.01	0.0003

(a)Reference 7.

2. Vapor Phase Flammability over Fuel Methanol

Air mixtures containing between 6.7 and 36% methanol vapor by volume are flammable at atmospheric pressure (8). Based on vapor pressure-temperature characteristics of methanol, this means that the saturated vapor above neat liquid methanol is flammable at temperatures between 10 and 43°C (50 to 109°F). For summer-grade gasoline, the comparable range of flammable vapors lies below -22°C (-8°F).

Addition of hydrocarbon fuels to methanol shifts the vapor flammability range to lower temperatures. Figure 1 shows experimental results for several methanol/hydrocarbon blends. These results were obtained at Battelle-Columbus under Ford sponsorship.

The Le Chatelier mixing rule relates vapor phase flammability limits of multicomponent fuels to the corresponding limits of the separate components. Using vapor pressure-temperature data for methanol and cofuels taken from the literature, one can predict the range of flammable vapors above methanol/ cofuel liquid blends. Predictions based on such calculations are in good agreement with the experimental findings as shown in Table III, in spite of the fact that a non-ideal vapor pressure results when methanol is added to hydrocarbon; i.e., the solution does not obey Raoult's Law. This is further complicated by the formation of azeotropes. The non-ideality of liquid methanol/ hydrocarbon solutions obviously will impact vapor phase fuel compositions. It turns out, however, that non-ideality has a relatively minor impact on the temperature range of the flammable vapors. It is completely dwarfed by the temperature dependence of the methanol/cofuel vapor pressures.

TABLE III

COMPARISON OF EXPERIMENTAL AND CALCULATED FLAMMABILITY LIMITS

(Temperature in °C)

Fuel	Experimental (Battelle)	Calculated
Methanol	+10 to +39	+9 to +40
3.5% Isopentane in Methanol	<-29 to +9	-31 to +1
5.0% Isopentane in Methanol	<-30 to -1	-36 to -5
7.5% Isopentane in Methanol	<-29 to -12	-41 to -11
10% Isopentane in Methanol	<-29 to -15	-45 to -15
10% Summergrade Gasoline in Methanol	-28 to +8	-23 to +9

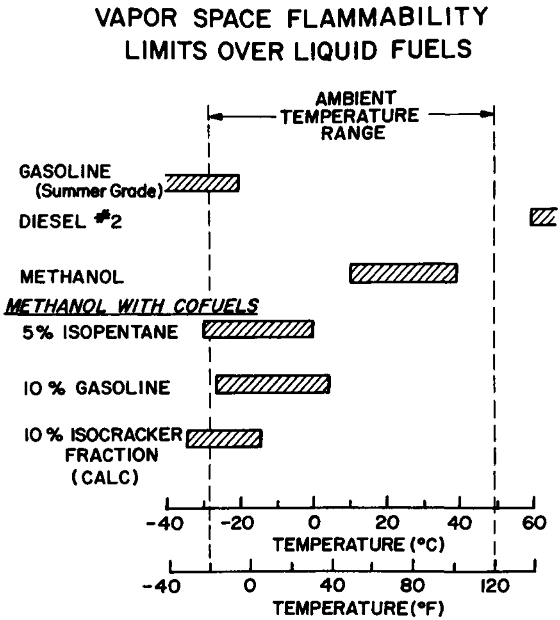


Figure 1

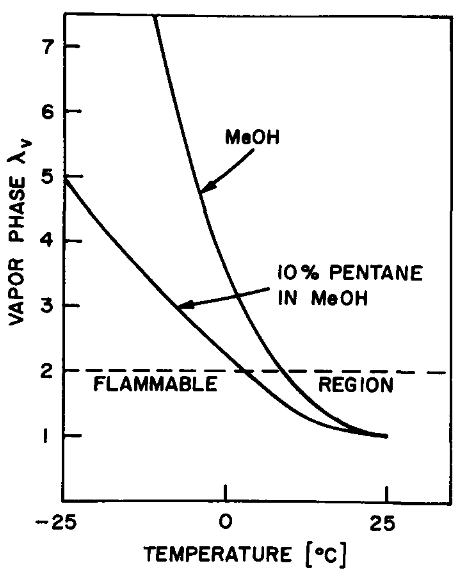


Figure 2

3. Coldstart Issues

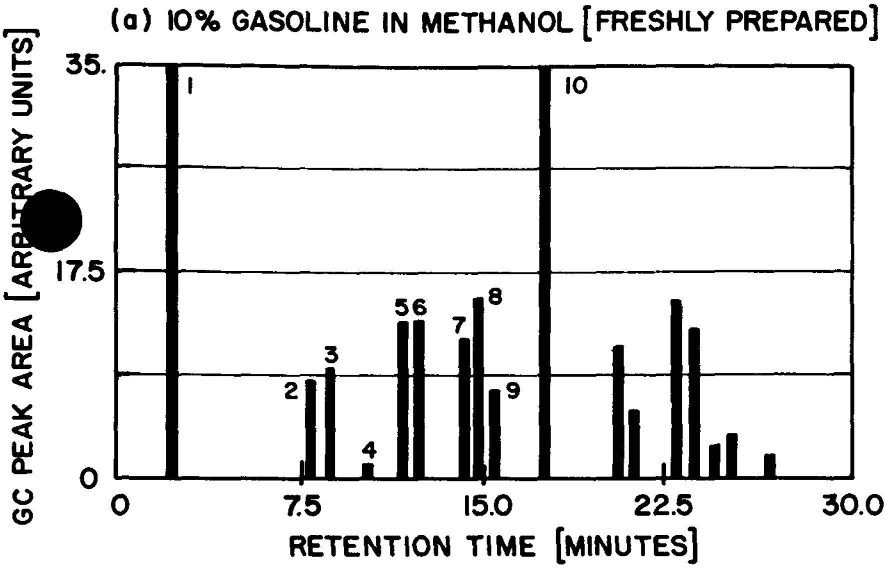
Starting a vehicle fueled with neat methanol is a major problem at low temperatures. Below about 10°C (50°F), the methanol vapor pressure is too low to produce the flammable air/fuel vapor mixture necessary for engine operation. To circumvent this, various low-boiling cofuels can be added to methanol in order to bring the resulting vapor back into the flammable range. The cofuel of choice and its concentration depends on minimum coldstart temperature requirements, and on economic considerations.

A computer code has been written to predict coldstart behavior of methanol/cofuel blends. A fixed total volume of liquid fuel is assumed to be injected into a fixed volume of air. The oxygen/fuel stoichiometry, λ, of the resulting vapor space is computed assuming equilibration at ambient temperature. Thermodynamic coefficients for methanol and each cofuel are used as input parameters. Vapor spaces with $\lambda > 2$ were assumed to be non-flammable; vapor spaces with $\lambda < 2$ were assumed to be flammable. The results, shown in Figure 2, are in rough agreement with preliminary vehicle test data. Additional data from cold climate fleets will be helpful to validate the model.

"Weathering" of coldstart cofuels (i.e., cofuel loss by evaporation) is a major unresolved issue. Finding cofuels that are intrinsically capable of starting fuel methanol vehicles at temperatures down to -30°C (-21°F) has not been a problem. However, in order for a cofuel to be useful, it must have high vapor pressures at extremely low temperatures. Therefore, such fuels volatilize readily out of methanol solutions at modest temperature elevations. Figure 3(a) and (b) show gas chromatograph (GC) traces of fuel methanol blends before and after standing open to the atmosphere at 15°C (60°F) for 8 hours. Most of the low boiling (high vapor pressure) gasoline constitutents are lost even in this relatively mild case. Weathering is even more severe at 60°C (140°F). Fortunately, today's closed fuel systems helps to mitigate this problem, but the fuel in the carburetor bowl is still susceptible to weathering. More work on fuel methanol weathering remains to be done.

CONCLUSIONS/OPEN ISSUES

1. The solution for reducing vapor phase flammability above the liquid fuel methanol is closely related to improving cold start. In both cases one uses a volatile cofuel to increase vapor phase fuel concentration. It seems likely that an optimal cold start additive will resolve the vapor phase flammability issue as well. Substantial cofuel concentrations, of order 5-10%, are likely to be required.


(a) 10% GASOLINE IN METHANOL [FRESHLY PREPARED]
GC PEAK AREA [ARBITRARY UNITS]
35.
17.5
0
1
10
2
3
4
5 6
7
8
9
0
7.5
15.0
22.5
30.0
RETENTION TIME [MINUTES]

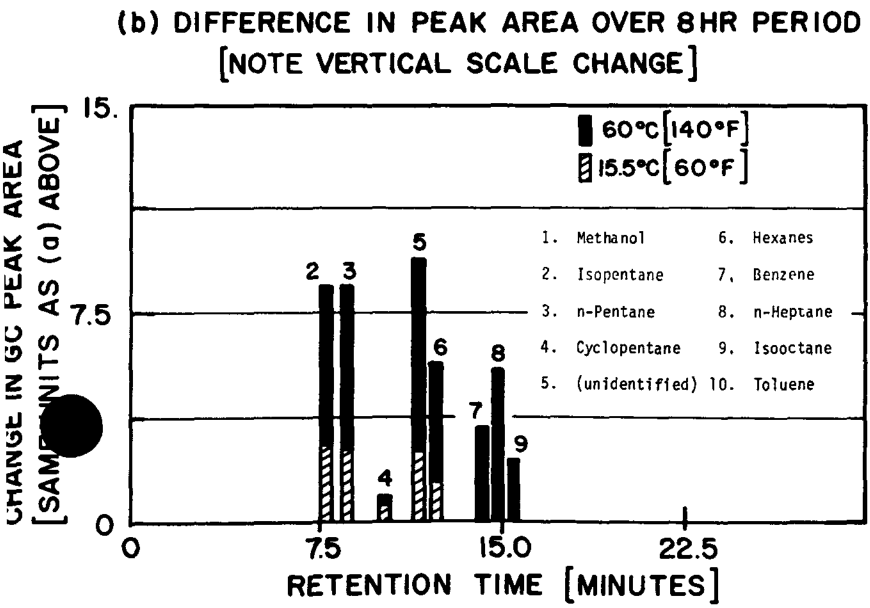

(b) DIFFERENCE IN PEAK AREA OVER 8 HR PERIOD
[NOTE VERTICAL SCALE CHANGE]
CHANGE IN GC PEAK AREA
[SAME UNITS AS (a) ABOVE]
15.
7.5
0
60°C [140°F]
15.5°C [60°F]
1. Methanol
2. Isopentane
3. n-Pentane
4. Cyclopentane
5. (unidentified)
6. Hexanes
7. Benzene
8. n-Heptane
9. Isooctane
10. Toluene
2
3
4
5
6
7
8
9
0
7.5
15.0
22.5
RETENTION TIME [MINUTES]

Figure 3

2. Weathering of the cofuel can be severe, particularly for the low boiling hydrocarbons required for satisfactory operation at extremely low temperatures.

3. 10 percent gasoline in methanol provides a flame luminosity equal to that of burning ethanol, which is visible. 10% gasoline/ methanol burns with minimal distillation effects, unlike isopentane/methanol where the yellow color of the flame decreases with fairly rapidly.

4. Addition of cofuel for resolution of the above concerns also serves to make the fuel more easily identifiable as a non-potable substance, thereby preventing mistaken ingestion. Addition of small amounts of volatile cofuel, such as gasoline, gives the fuel the odor and taste of the cofuel.

5. While engine wear in methanol-powered vehicles presents no problem in a large majority of tests, high wear has been encountered under certain conditions. The reasons for these differences are poorly understood, particularly the role of trace organic chlorides and/or acids. Development of anti-corrosion/ antiwear additives should be explored.

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ASSESSING THE POTENTIAL OF RETROFITTING BOILERS WITH FLUIDIZED BED SYSTEMS

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INTRODUCTION

In today's highly volatile energy market, more and more attention is being paid to recovering as much energy as possible from on-site waste materials or centrally located waste materials such as wood waste, plastics, coal and various other types of solid waste material. Most plants have the capability to generate their steam requirements, whether for process or power production, by utilizing gas or oil fired boiler systems. The current emphasis is to replace the fossil fuel dependence which has created shutdowns and high operating costs due to the fuel availability and costs.

Interest has been increasing from these plants to consider not only recovering energy from their solid fuels, but utilizing their existing boiler equipment as well. The fact is, most plants have relatively new boiler systems or, at least, relatively well maintained equipment. For these plants, expending large amounts of capital to completely replace operable and quality equipment with new boiler systems is not possible or practical. In those situations, the first consideration is to utilize the existing equipment incorporating the capabilities to burn solid fuels and waste streams.

For the last ten years, at least, fluidized bed technology has been applied heavily in these situations. Initially, fluidized bed combustion systems, designed essentially as incinerators, were utilized to retrofit existing boilers as waste heat fired systems. In recent years, however, economic considerations of purchased fuel costs and optimum operation have dictated more economical boiler conversions which reduce stack losses and improve recovery of the useful energy from the fuel as well as to utilize the boiler to its capacity, more so than would be observed in a direct, waste-heat fired system.

A prime consideration for a company evaluating a boiler conversion is knowing what the final operation performance of that boiler will be when converted to solid fuels firing. Past experience with converting boilers to fluidized bed firing, both combustion and gasification, has generated a significant amount of valuable information on the predictability of boiler performance and the reliability of boiler operation downstream. The remaining part of this paper discusses general considerations to be reviewed and evaluated in considering boiler conversion and determining the expected boiler performance under the desired operating conditions.

DISCUSSION

Prior to discussion of the boiler conversion applications, a brief introduction to fluidized bed technology will help to establish a better background. Fluidized beds and fluidized bed combustion, or gasification, involve the input of a solid fuel, such as coal, wood, peat, etc., into a bed of inert material. This material might be limestone for coal combustion or it might be an inert refractory sand material for various other types of solid fuels. Combustion air is passed vertically upwards through the bed material until the buoyancy force of the air is sufficient to suspend the bed material in the air stream. By maintaining the air velocity at this flowrate or greater, the bed of solid material takes on many of the characteristics of a liquid and will exhibit a behavior very similar to a pot of boiling water. The phenomena occurring in this fluidized region include very high heat and mass transfer rates due to the interaction of the solid particles and the gas streams. For this reason, fluidized bed combustion provides the capability to burn fairly low quality fuels having high moisture contents and/or very low BTU values. In addition, the bed material, when heated to high temperatures, provides a very high thermal stability to the system which not only allows for utilizing low quality fuels, but also tends to stabilize the combustion characteristics of the system when exposed to various fluctuations in the fuel quality. Fluidized bed combustion, either in a straight fluid bed or in a circulating bed system, allows a much wider range of flexibility in fuel characteristics than that experienced with a traveling grate or fixed grate type of combustion unit. For that reason, the fluidized bed has become much more universal in its applications to boiler conversions and new plant installations where use of a variety of fuel types might be considered.

FIRING OPTIONS

When considering the conversion of an existing boiler to fluid bed solid firing, generally three options are potentially feasible. These include:

1) Combustion of the solid fuel in a separate combustion chamber, and ducting the hot gases into the existing boiler for heat recovery;

2) Close coupling the fluid bed system to the bottom of an existing boiler furnace with or without the use of in-bed steam generating tubes;

3) Gasifying the fuel in a separate chamber, cleaning and ducting the low-BTU gas to the boiler and igniting the low-BTU gas in the existing boiler furnace.

The use of any of the above processes has certain advantages and di advantages. The use of an external combustion system as in Option minimizes the impact on the existing boiler systems. Only minor modifications are required to introduce the hot flue gases into the boiler furnace. Flue gas temperatures, however, must be limited to between 1800°F-2000°F to avoid ash slagging. This temperature is normally controlled by the addition of air well in excess of normal combustion requirements. A bituminous coal with a higher heating value (HHV) of 12,000 BTU/# would typically require 11.5 pounds of air per pound of coal when fired in a stoker boiler with water walls, and would require nearly twice that quantity when fired in an external combustion chamber and ducted to the furnace.

Erosion considerations in the boiler convective sections limit the gas velocities allowable with particulate laden flue gas. For particulate loadings typical of fluid bed combustion, velocities should be limited to 50 to 60 ft./sec. This limitation, coupled with the excess air requirements to avoid ash slagging, results in as much as 50 percent derating of an existing boiler when a separate combustion chamber is utilized.

Gasification is an option for consideration if fuel characteristics are constant. When considering moderately dry biomass material, or other types of high volatile content fuels, a fluid bed gasifier can deliver a high quality, low BTU gas to be combusted directly in the furnace. Although mass velocities will be higher than gas or oil firing at the same steam output, this system utilizes most effectively the radiant surface of the boiler furnace and minimizes excess air requirements for complete combustion of the fuel gas. Recent startup and successful operation of a fluid bed gasifier conversion on a CE boiler in the State of California's Central Heating Plant Facility in Sacramento, has demonstrated the performance and reliability of this method of conversion. Limited by lower grade fuel characteristics and by the use of the existing boiler ID fan, the gasifier has operated successfully at steam rates in excess of 55,000 #/hour, 275 PSIG. Th boiler was originally designed for 60,000 #/hour on gas or oil. T gasifier systems are very dependent upon fuel quality, however. Unli a fluid bed combustor wherein all of the fuel's energy is converted directly to hot gas, the gasifier converts only part of the energy into sensible heat, with the remainder going into combustible gas volatilization. Should the quality of the fuel vary significantly, say from 20 percent to 40 percent moisture content in wood, the output of the gasifier might be reduced by as much as 50 percent. Such fluctuations would not exist with a combustor.

The primary focus of this paper is the direct coupling of a fluid bed to the bottom of an existing boiler furnace. The advantages include the elimination of a separate combustion chamber and its associated refractory lined breeching and space requirements, better utilization of the radiant heat transfer surface in the boiler furnace section, and in-bed heat transfer steam generating tubes that minimize derating of the boiler by reducing the excess air requirements. In addition, variations in fuel quality can be accommodated without adversely affecting performance.

RETROFIT PROCEDURE

A procedure to evaluate the feasibility of retrofitting an existing boiler to solid fuel fluid bed firing has been developed. The details of the evaluation will vary with each boiler under consideration and involve both a mechanical and thermal analysis of the existing boiler and its proposed fluid bed operation.

The mechanical analysis addresses space requirements below the existing boiler for installation of the fluid bed assembly and associated subsystems. Typically, from twelve to twenty vertical feet is required, depending on the system size. Should it be necessary to remove any boiler furnace floor tubes to permit installation of the fluid bed assembly, the mechanical analysis would include the design of new manifolds and new external water feeders to ensure the integrity of the boiler circulation system. Thermal analysis addresses the predicted performance of the existing boiler and fluid bed assembly. This includes a heat and mass balance for the fluid bed and a predicted performance for boiler furnace, superheater (if applicable), generator tube bank, and economizer/air heater (if applicable).

CASE HISTORY, NORTHERN STATES POWER, FRENCH ISLAND PLANT

In order to illustrate this procedure, the installation at Northern States Power Company's French Island Plant in LaCrosse, Wisconsin will be examined. The boiler under consideration was an Edgemore boiler and was designed for coal firing on a traveling grate stoker. During the mid-1960's, the boiler was converted to oil firing with the addition of two oil burners in the front wall. In the mid-1970's, oil firing was less desirable and the potential for wood firing of the boiler was examined. Wood was economically available from various sawmills within the region.

Consideration of the physical layout of the boiler indicated that it would be possible to convert to a fluid bed by direct coupling to the boiler furnace. With the boiler being top supported and located above a fully accessible basement, sufficient area was available directly below the boiler to incorporate a fluid bed unit and its associated bed cleanout and recycle systems.

Initial analysis indicated that 289 square feet of grate area was available in the base of the furnace. A fluid bed assembly of 289 square feet (inside dimensions) and no in-bed surface was estimated to be capable of generating approximately 75,000 lb./hour of 450 PSIG, 750°F superheat steam. Since the desired steam output was between 125,000 and 150,000 lb./hour, additional steaming surface was needed within the fluid bed region.

The determination of the required in-bed surface was complicated by the expected fuel variation in both moisture content and particle size. Since a variety of fuel suppliers would be utilized, the fuel would vary from dry sawdust to wet winter-stored bark with variations in size from minus three-inches to fines. For design purposes, t fuel utilized for design purposes was 40-50 percent moisture cont and of a size distribution such that 65 percent of the energy in t fuel would be released into the fluid bed. On that basis, a configuration of horizontal, forced circulation in-bed surface of 630 square feet of surface area was established.

Based upon experimental data from in-bed heat transfer testing, it was estimated that under design conditions, as much as 50MM BTU/hour could be transferred to steam in the bed surface exchanger. Based on 450 psi, saturated water, this generated as much as 65,000 #/hour of steam in the tubes.

A circulation ratio of 10:1 was established for the forced circulation in-bed surface. A series of penetrations into the lower boiler drum (mud drum) were made and tubes were rolled into the drum to serve as feeder tubes. These tubes were collected into a manifold and piped to a circulation pump. The pump provided the necessary head for circulation through the horizontal in-bed surface. The steam and water mixture was collected in headers and returned to the steam drum for separation of the steam/water mixture. The boiler furnace and generator bank natural circulation system was not otherwise modified and continued to operate as originally designed.

The thermal analysis of the boiler was made by considering the boiler as a black box and doing an overall heat balance for a 125,000 #/hour steam flow assuming th exhaust gases out of the economizer would be on the same order of magnitude as the current operation (500°F). With in-bed heat transfer surface, 40 percent excess air was utilized for analysis. Fuel feed and air flow rates were determined. Using a 65 percent heat release to the bed and appropriate in-bed heat transfer coefficient for the in-bed surface, the in-bed heat transfer and bed temperature were calculated, as previously indicated.

The boiler furnace, superheater, generator tube bank and economizer were considered a heat recovery train with the calculated flue flowrate and temperature leaving the fluid bed as the inlet conditi

From this analysis, it was determined the final steaming conditions for the boiler would be 450 psi and about 680°F, somewhat short of the desired 750°F. Based on this prediction, additional analysis was conducted to determine what methods might be available to increase the superheat temperatures if the actual operating conditions were below 750°F. One option was that tube stubs in the superheater manifolds were available for additional surface area. The consensus was that if a 700° superheat could be achieved, it would be acceptable for the operation of the turbine under most conditions. Therefore, on the basis of this analysis, the decision to proceed with the retrofit was made and the system was designed and built accordingly.

The fluid bed assembly was started up in November, 1981, and to date, has logged over one year's operation. Actual operating conditions have been verified throughout a series of tests performed over the past eight months. A summary of these tests is shown in the accompanying table, along with the predicted values from the original analysis. can be seen on the basis of steam flow and conditions, the results quire close to one another. Steam production rates of 125,000 to 150,000 pounds/hour have been maintained, with most operation around 135,000 pounds per hour. Superheat temperatures of 660° to 690°F were achieved, in close agreement to the predicted values. Bed temperatures have varied with fuel variety, but for the most part have been around the 1600°F range predicted.

TABLE I

NORTHERN STATES POWER COMPANY, LaCROSSE, WISCONSIN
PREDICTED AND OPERATING CONDITIONS

	PREDICTED	ACTUAL*
Steam Conditions		
Flow	123,000	129,000
Pressure	450	448
Temperature	656	663
Bed Temperature	1600	1560
Vapor Temperature	1550**	1620
Boiler Exit Temperature	474	440
Fuel Feed, lb./hour	37,263	38,600
Stack Gas Flowrate, lb./hour	229,540	415,846

*Based upon emission tests, 3/17/82
**Temperature at top of furnace inlet to superheater screen section.

One area of significant variation which still remains unresolved is the air inleakage into the boiler. Originally, inleakage rates of around 10 percent of total mass flow were estimated. The inleakage was considered mostly to evaluate flue gas exhaust losses and velocities through the convective bank of the boiler. Operating data indicates that inleakage may be as much as 50-60 percent and could be impacting formance by diluting the O_2 signal being used for control. With the eption of this inleakage consideration, most other operating conditions have remained very similar to those predicted. Recent test programs utilizing other kinds of fuels, most notably coal and rubber tires, have demonstrated the ability of the unit to adapt to changing fuel characteristics without significantly changing output conditions.

During the last part of 1982, Northern States Power added the additional superheater tubes available to boost their superheat temperatures by about 20-25°F; they are now running at superheat exhaust temperatures on the order of 725-730°F.

ATMOSPHERIC FLUIDIZED BED COMBUSTION (AFBC) DEVELOPMENT STATUS

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INTRODUCTION

During the early 1970s, initial AFBC process data was principally developed from numerous bench-scale test rigs. One of the forerunners was the Pope, Evans, and Robbins 0.5-MW bench-scale combustor located at Alexandria, Virginia. More recently, larger scale process units (such as the Electric Power Research Institute (EPRI)/Babcock & Wilcox (B&W) 6 ft by 6 ft unit at Alliance, Ohio) and industrial-sized units (such as the Pope, Evans, and Robbins unit at Rivesville; the Department of Energy (DOE)/B&W unit at Georgetown University; and the DOE/Combustion Engineering unit at the Great Lakes Naval Station) have shown AFBC to be a viable technology. The attractiveness of AFBC for use in the industrial sector has been demonstrated; however, before this technology can be commercialized for utility applications, data from a pilot plant operating at utility conditions is required. TVA's 20-MW AFBC pilot plant began operation in May 1982 to obtain this data.

STATUS OF TECHNOLOGY

Performance of the AFBC process over the last few years has shown marked improvements (Figures 1 and 2). The more significant improvements can be attributed to the recycle of elutriated material from the combustor. To achieve 90-percent sulfur removal from a coal containing 4-percent sulfur, the technology has progressed from a

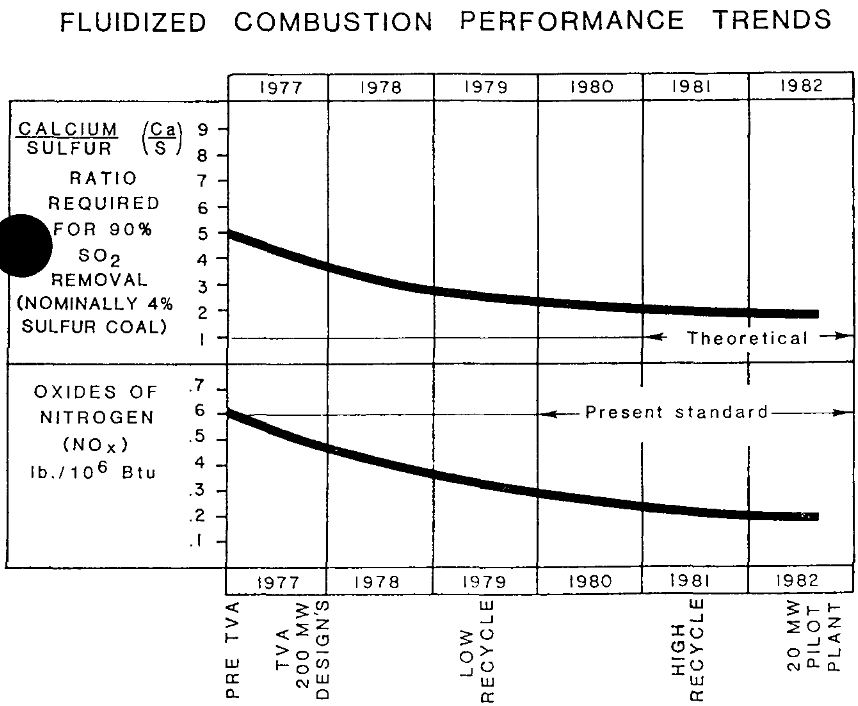


Figure 1

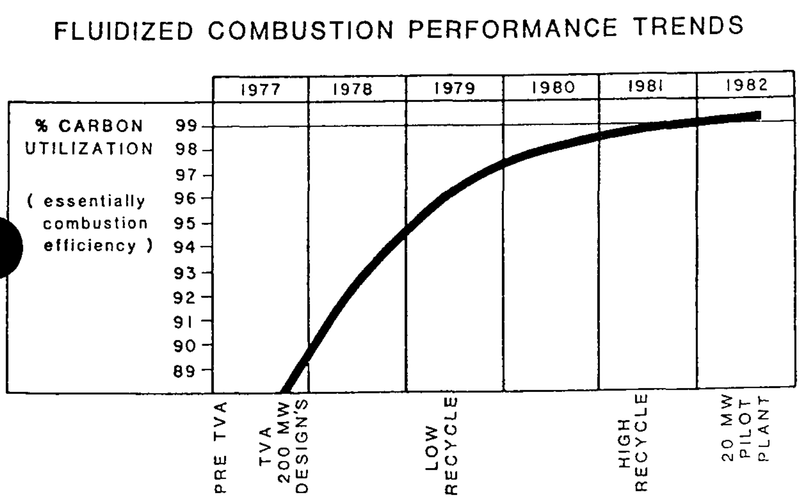


Figure 2

predicted calcium-to-sulfur ratio of about 5.0 to 1.0 (4.5 for 85-percent removal) in early 1977 to a ratio of close to 2.0 to 1.0 today. The predicted ratio for TVA's pilot plant is 2.0 to 1.0.

Similar improvements in nitrogen oxide (NO_x) emissions have also been observed. The Rivesville design basis showed 0.6 lb of NO_x (0.257 kb/GJ) per MBtu in early 1977. Current data from the EPRI/B&W 6 ft by 6 ft AFBC unit indicates that 0.2 lb/MBtu (0.086 k/GJ) or better is possible. The predicted level in the 20-MW pilot plant is less than 0.3 lb/MBtu (0.129 kb/GJ).

Carbon utilization has also been improved over the years. Studies in the mid-1970s indicated that only about 89-percent carbon utilization was achievable in the main combustor. Recent results from the EPRI/B&W 6 ft by 6 ft AFBC unit indicate that 99-percent or greater carbon utilization is achievable in the main combustor. The predicted level for the 20-MW plant is approximately 99-percent carbon utilization.

TVA'S HISTORY IN AFBC

TVA's developmental activities began in earnest in September 1976 when the TVA Board of Directors authorized $4 million to prepare a preliminary conceptual design of a 200-MW demonstration plant and to perform technical support research projects.

A major task of the preliminary conceptual design studies was to identify areas of technical uncertainty requiring additional R&D in order to assure successful operation of the demonstration plant. Four major areas were identified that required more extensive investigation:

1. Materials, feed, distribution, and disposal.

2. Bed design and performance correlations (velocity, bed height, and Ca/S ratio versus combustion efficiency and sulfur capture).

3. Control (startup and load following).

4. Construction materials.

Items 2 and 4 could be adequately addressed on small-scale experimental units; however, no existing or planned test facility could test proposed control and feeding techniques satisfactorily. A new large-bed pilot plant was needed to test control techniques and turndown and to verify the feed system.

Other areas in which additional R&D was identified but are not considered as critical as those above were:

- Air distribution design
- Agglomeration
- Dust collection
- Precalcination

- o Sorbent regeneration
- o Spent bed material handling, heat recovery, and disposal
- o Development of more reactive absorbents

To address these major technical uncertainties, TVA has built a 20-MW AFBC pilot plant and has also conducted over 40 individual experimental and analytical studies.

TVA'S 20-MW AFBC PILOT PLANT

To provide design confidence and the flexibility to test process improvements, TVA has constructed the 20-MW(e) AFBC Pilot Plant at TVA's Shawnee Steam Plant near Paducah, Kentucky. On August 6, 1982, the pilot plant was dedicated, and the unit has run approximately 1,052 hours and consumed approximately 9.9 million pounds of coal and 3.7 million pounds of limestone. A project team, needed to carry forward the design, erection, and operation of the 20-MW AFBC Pilot Plant, was assembled. A concerted effort was made to utilize available expertise and to learn from past and ongoing FBC activities. Project responsibility was handled by TVA's Division of Energy Demonstrations and Technology. The boiler and associated equipment were designed and built by B&W as the prime contractor and Stone & Webster as a subcontractor. The coal- and limestone-handling facilities and other balance-of-plant features were designed and built by TVA's Office of Engineering Design and Construction.

The main objective of the pilot plant program is to simulate utility-applicable components and systems in order to resolve the technical issues associated with the utility application of AFBC. The technical issues associated with utility application of AFBC are:

1. Combustion Efficiency--Variation of bed depth and superficial velocity to increase in-bed residence time, higher freeboards, and the recycling of unburnt carbon back to the bed are considered to be viable methods to improve combustion efficiency.

2. Limestone Utilization--Limestone particle size, recycle rate, freeboard height, bed depth, and superficial velocity are the critical parameters in sulfur dioxide (SO_2) capture and in minimizing the amount of limestone used in the process.

3. NO_x Control--Staged combustion has been shown to be effective for NO_x reduction in small AFBC boilers, but the effect of large boiler cross-sections on NO_x reductions must be studied.

4. Material Selection--Current test results indicate that standard boiler materials used in an AFBC boiler will have a satisfactory life. However, the long-term corrosive and erosive effects under a variety of operating conditons remain unknown.

5. Coal and Limestone Feeding--The optimization of the number of feed points per bed area, the accurate splitting of fuel and

sorbent, the erosion of feed piping, and the feeding technique (overbed or underbed) must be studied and resolved prior to constructing a utility-scale AFBC unit.

6. Recycle System Design--Recycling of large quantities of fly ash to improve combustion efficiency and sulfur capture may require more efficient mechanical collectors than are currently available.

7. Load Control--The application of AFBC to utility service will require the design of an integrated control system to achieve satisfactory startup, shutdown, and load following operation. Steam production, superheat and reheat temperature control, pressure control, sulfur capture, and their complex interrelationships are areas the designers of AFBC boilers with multiple-bed compartments must address.

20-MW PILOT PLANT TEST PROGRAM

A developmental test program is being undertaken by TVA and EPRI to develop AFBC for utility applications. Most, if not all, of the uncertainties identified by TVA and EPRI will be addressed during the 4-year test program. Implementation of the test program will be done by TVA, who will operate the facility, analyze and interpret the data, and evaluate the design and operating information to support the design of TVA's AFBC demonstration-scale plant. In addition, the test program will provide scaleup data to meet the diversified commercial needs of the U.S. utility industry.

The 20-MW AFBC Pilot Plant test program is directed toward accomplishing the following major goals:

- Prove that reliable and cost-effective performance of an AFBC boiler and auxiliary system can be obtained under utility operating conditions to facilitate the rapid development of this technology.

- Develop AFBC load control capabilities such that commercial AFBC boilers can be designed to meet a wide range of load applications (i.e., cycling, shifting, sliding, pressure, etc.).

- Test, compare, develop, and evaluate various large-scale auxiliary system design options as a basis for future commercial AFBC designs.

- Develop capability for adequate emission controls and combustion efficiency over a range of operating conditions and equipment configurations.

- Evaluate and/or develop the necessary predictive modeling tools to enable correlation of test results for use in designing large AFBC utility units with confidence.

- o Establish a data base for a range of coal and limestone to enable scaleup of AFBC to commercial size for a range of applications.

A detailed test plan has been developed by TVA and EPRI in order to define the scope of work and the schedule of testing. The test plan provides an overall R&D strategy and establishes priorities for testing. Flexibility is built into the test plan to allow for a variety of testing decisions based on previous test results as well as changes in developmental priorities.

Startup and acceptance testing are well underway. The activities in this phase are:

1. Component and system acceptance including cleaning, shakedown, and run-in.

2. Collection of preliminary data and information regarding component and system performance, operating characteristics, and baseline measurements.

3. Calibration and checkout of instrumentation including process monitoring, controls, and performance analyses.

4. A series of pre-operational tests on material handling, preparation and feed systems, air and flue gas systems, and boiler systems.

The facility has been accepted for formal testing, and a two-part program of test campaigns is now underway.

TECHNICAL SUPPORT ACTIVITIES AT TVA

In preparation for the design and operation of the pilot plant, several major technical support activities were conducted. These studies were aimed at improving our understanding of the fluid-bed process, to mitigate as much as possible any unexpected events in the pilot plant operation, and to better define the design changes necessary to construct a large utility AFBC plant.

FEED SYSTEM

One of the potential problems with AFBC, as well as with other coal-burning technologies, is in the development of a reliable coal/limestone feed system. In order to address this problem prior to starting the 20-MW AFBC pilot plant, three major projects were undertaken.

1. At Oak Ridge National Laboratory (ORNL), bench-scale experiments were conducted to determine limitations on transport velocities and surface moisture levels for conveying coal and coal/limestone mixtures.

2. At the University of Tennessee at Knoxville, a cold-flow test facility was designed, constructed, and operated to investigate various coal/limestone feed nozzle configurations that would prevent bed material shifting when the bed is slumped or shut down. Feed nozzles in the pilot plant are a product of this project.

3. The most extensive project involves the testing of a full-size Fuller-Kinyon pump feed and splitter system. A test facility (Figure 3) constructed at TVA's Watts Bar Steam Plant simulate operating conditions by utilizing coal from the plant's coal p and presized limestone procured from a nearby quarry. A 12-month testing program was completed. The tests conducted at this facility have helped to minimize pilot plant operational delays and should increase the probability of successful performance for demonstration and commercially sized AFBC. The Fuller-Kinyon pump, used extensively in the cement industry, appears to be uniquely suited for feeding an AFBC boiler.

MATHEMATICAL MODELS

A steady-state model, as well as a transient model, has been developed for the pilot plant. The approach taken at TVA has been to develop semi-empirical and semi-mechanism models. The principal objectives of the steady-state model development are:

1. Identify information gaps and assist research planning.

2. Analyze data from 6 ft by 6 ft 20-MW and other facilities.

3. Predict effects of operation and design parameters upon performance characteristics under steady-state conditions.

4. Process optimization for multiple objectives (carbon utilization, SO_2 capture, NO_x emission, cycle efficiency, economics).

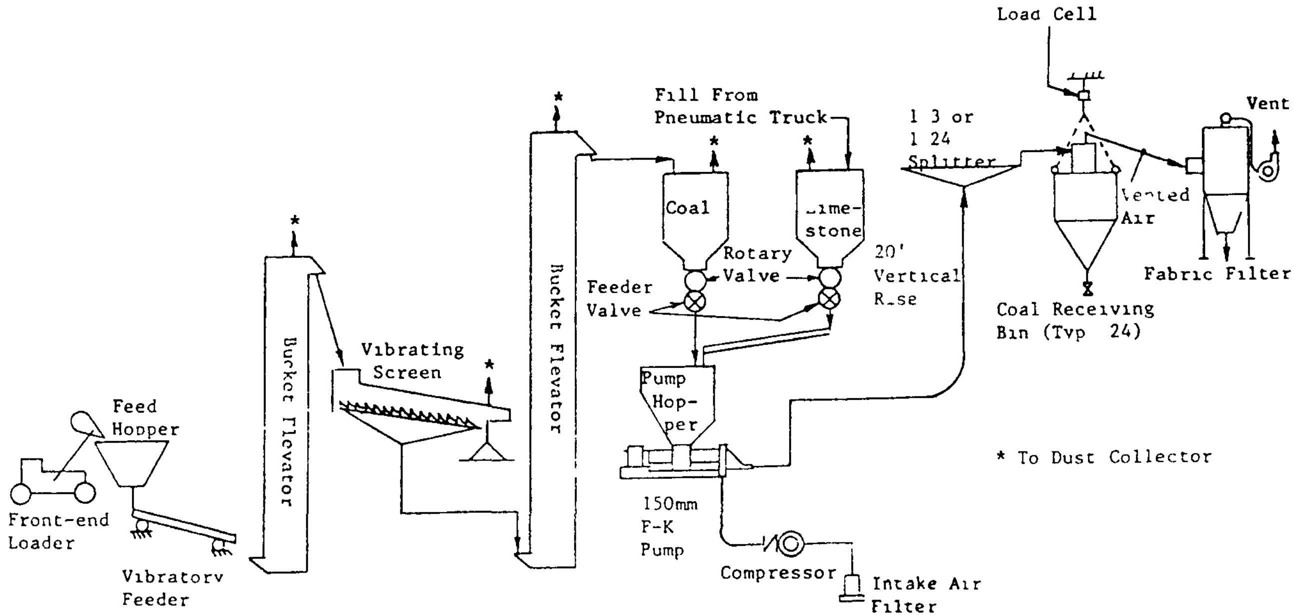
5. Provide guidance in formulation and revision of the 20-MW test plan.

Likewise, for the transient model development, our principal objectives are:

1. Predict transient behavior and dynamic characteristics of the 20-MW pilot plant in both open- and closed-loop configurations

2. Evaluate turndown schemes, load following capability, and alternate control strategies.

3. Aid the 20-MW pilot plant transient testing through analysis of data and potential reduction of experimentation requirements.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Vibrating
Screen
Bucket Elevator
Pump
Hop-
per
Feed
Hopper
* To Dust Collector
Front-end
Loader
150mm
F-K
Pump
Compressor
Intake Air
Filter
Vibratory
Feeder

Figure 3

In addition, TVA also funded activities to characterize fundamental phenomena and to provide basic information on the effects of certain design and operational paramenters. A number of these experiments were conducted by Massachusetts Institute of Technology, ORNL, Accurex, along with several others.

RECYCLE

The EPRI/B&W 6 ft by 6 ft AFBC unit at Alliance, Ohio, has provided evidence that adequate carbon utilization and a significant decrease in limestone utilization can be obtained by recirculating a portion of the fly ash to the combustor rather than using a second combustor. Tests of this approach with high recycle rates have also been undertaken at ORNL and early testing at General Atomic (GA).

They have found that a calcium-to-sulfur ratio of 2:1 can be obtained at reasonable recycle ratios. Recently completed work at GA has continued to confirm these improvements in carbon and calcium utilization as the recycle rate is increased.

BOILER MATERIALS OF CONSTRUCTION

Earlier concerns over sulfidation of nickel in T304 stainless steel superheater tubes, with potential in-bed reducing atmospheres, do not appear to be a problem. The absence of attack in hot tests at low oxygen levels in studies at FluiDyne and ORNL indicates a satisfactory performance under these conditions. We now believe that standard boiler materials may be used with due regard to maintaining excess oxygen in critical areas through correct design and process control. The 20-MW AFBC pilot plant should provide the required confirmation that standard practices are adequate.

CONCLUSIONS

Based on recent technology improvements, the attractiveness of AFBC has been significantly enhanced. The use of increased recycle of elutriated fines results in significant improvements in AFBC technology. For example, the calcium-to-sulfur stoichiometry required for 90-percent sulfur removal has been reduced by one-half. Carbon utilization has been increased to the 99-percent or greater level required for utility applications, and oxides of nitrogen should be in the range of 0.3 lb/MBtu. The 20-MW AFBC pilot plant, which is undergoing acceptance testing, is expected to confirm the performance capabilities which have been achieved in smaller units and provide the design information needed to confidently scale up this technology for use in utility-size AFBC boilers.

OPERATING EXPERIENCE OF THE FBC BOILER AT IOWA BEEF PROCESSOR'S AMARILLO, TEXAS PLANT

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Abstract

A 70,000 lb./hr. coal-fired fluidized bed combustor is currently undergoing acceptance testing in Amarillo, Texas. In the 300 hours of round-the-clock testing performed to date, the unit has experienced an availability of 98%. Preliminary indications are that the gaseous emission levels are low: the CO, SO2 and NOX emissions are 100, 50 and 100 ppm, respectively, while the burner operates at 20% excess air. The unit is able to continuously follow load changes to 1/3 of full load, at rates of 15% per minute. Below this, the burner is operated in a cycling mode.

The FBC is a novel dual-bed design that enables it to achieve high desulfurizing efficiencies in a short (14 ft. tall) package unit. The system also incorporates a package coal feed system that reduces costs in that area. Comprehensive performance measurements are scheduled for March, 1983. A history of the development of the unit is included.

Introduction

My son Andy is becoming an Eagle Scout this year, so over the years I've had many occasions to hear the Boy Scout values as expressed in the Scout Law. Recently, I've reflected on the notion that industrial boilers, too, should have at least some of the virtues included in the Scout Law; in particular, a boiler should be thrifty, clean and trustworthy. But when it comes to meeting these values, the standards are set by gas and oil boilers, with conventional coal boilers falling well behind, for reasons that are all too well understood.

The question that we posed ourselves, and in fact, long before Andy even thought of becoming an Eagle Scout, was: does fluidized bed combustion provide a new opportunity for coal-fired boilers to become significantly more thrifty, clean and trustworthy than conventional units? The answer, we concluded, was yes, but only if FBC's were designed specifically with those goals in mind. Improvements over conventional FBC's were required in four areas, we concluded, and the resulting system is what we call Wormser Grate. The areas are identified in table 1.

A. THE DESIGN CONCEPTS.

1. The dual-bed package boiler.

One of our original targets was that the FBC should be short enough to ship so the resulting unit could be built as a package boiler. Package boilers have traditionally been the low-cost design, primarily because they provide the efficiencies of factory-production instead of the high costs of units are only marginal at desulfurizing, because the SO2 emitted by coal and volatiles in the freeboard doesn't make sufficient contact with the limestone in the bed.

To overcome this problem, conventional-FBC designers have made the beds deeper - typically 3 or 4 feet - which increases the splash zone of limestone above the bed and does a better job of desulfurizing. Recycling of the ash and limestone is also used. But these systems are 30 or more feet tall, too tall to build as package units.

Our approach has been to use two beds, with combustion occurring in the lower bed, and desulfurization in an upper bed that contains the limestone; see figure 1. This way, the SO2 emitted in the freeboard as well as the rest of the combustion bed, all has to pass through a layer of limestone, and the need for deep beds is avoided. The result is that we can use the shallow beds needed for a package boiler, but still get good desulfurizing action. In fact, we've measured SO2 removal efficiencies as high as 97% at a Ca/S of 7, and 90% at a Ca/S of 3.7, using a two-bed design that is under 14 feet tall.

2. An improved coal feed system.

The fuel feed system of a coal-fired boiler typically costs as much as the boiler itself. By contrast, an oil-fired boiler needs only a tank, pump, and feedpipe, which together cost much less than the boiler. The oil system has the added benefits of being sealed and therefore clean, and permitting the remote location of the fuel tank.

In designing our fuel feed system, we used the oil-fired system as our model, while taking into consideration the special requirements of the FBC. The design of an FBC coal feed system involves a sequence of two decisions: whether to use crushed or uncrushed coal, and whether to use a direct or indirect feed system. The issues are as follows.

Table 1
FEATURES OF WORMSER GRATE

1. Dual-Bed Package Boiler

2. Coal Feed Package

3. Storage Bed Control

4. Retrofit Capability

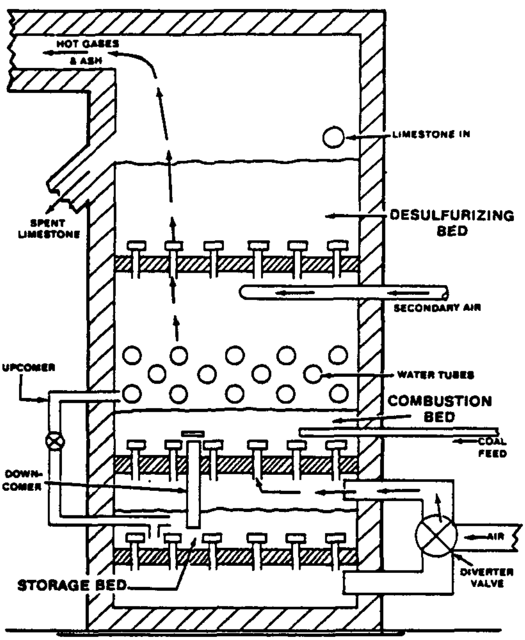


Figure 1
Cross-section of Wormser Grate

a. Crushed vs. uncrushed coal.

The selection between crushed and uncrushed coal has implications regarding the equipment for the preparing and transferring the coal to the burner; see table 2. Table 3 lists the advantages of using uncrushed coal and table 4, the disadvantages.

The advantages of the uncrushed coal are predominantly economic: the first-cost advantage, due to less equipment, is significant in small boilers, though the difference dwindles in boilers larger than 50,000 lb./hr.

The disadvantages of uncrushed coal relate primarily to coal cost, and process reliability. Double-screened coal required with the uncrushed coal units costs as much as ten to twenty dollars per ton more than the run-of-mine coal usable in the crushed-coal systems.

Stone accumulation in the bed is a problem peculiar to FBC's. Only a few percent of stone with the coal is enough to build up a layer of stones several feet deep in a week, unless the stone is somehow removed. But with uncrushed coal, some of the stones are an inch or more in diameter, and are hard to remove. Experience has shown that such beds must be shut down and cleaned out as often as weekly, to avoid defluidization by the stones. With crushed coal systems, the problem is avoided altogether by the crusher, which reduces any stones to a fluidizable particle size.

In choosing the coal system, we opted for the crushed coal approach, and then proceeded to work on the economics as follows.

b. Direct vs. indirect coal feed systems.

The second decision regarding the design of the coal feed system is that of direct vs. indirect systems, as summarized in table 5: the terms "direct" and "indirect" are defined in the table. The surge tanks and oversized conveyors of the indirect systems are the price of obtaining a reliable feed system with uncrushed coal. The direct system is made possible by the inherent reliability of the pneumatic conveying of dried, finely divided coal, and approaches in simplicity, if not the cost, of the oil-fired system.

In selecting the coal feed system, we opted for the direct method because of its lower costs. To further reduce costs, we selected a cascade design (figure 2) whereby coal enters from the bin at the top and falls by gravity through the various components until it emerges at the pneumatic-conveyor pipes at the bottom. This design shares many of the economies of the package boiler concept insofar as design is standardized and it can be shipped, pre-assembled, from factory, with a minimum of custom engineering or field labor.

To accomplish it, however, we had to develop a novel coal drier. The mill-drying systems used with pulverized-coal units use several times as much air as is desirable with a shallow-bed FBC; as a result, we developed our own drier: figure 3.

We also developed our own coal-stream splitter, primarily to improve on existing designs' accuracy of division at low flow rates.

Table 2

EQUIPMENT REQUIRED FOR CRUSHED AND UNCRUSHED COAL SYSTEMS

	Uncrushed Coal	Crushed Coal
Conveyor to FBC	Screw, or Dense-Phase Pneumatic	Dilute-Phase Pneumatic
Injector at FBC	Over-the-Bed Spreader	Under-the-Bed Nozzles

Table 3

ADVANTAGES OF UNCRUSHED COAL SYSTEMS

	UNCRUSHED COAL	CRUSHED COAL
Coal Preparation Equipment Required	None	Drier Crusher Stream Splitter
Feed Pipes per 100 mm BTU/hr.	2	20
Feed Pipe Size	~ 5"	~ 1½"

Table 4

DISADVANTAGES OF UNCRUSHED COAL SYSTEMS

	UNCRUSHED COAL	CRUSHED COAL
Ability to Convey Wet Coal Fines	Poor	Good
Ability to Burn Coal Fines	Poor	Good
Double-Screened Coal Required?	Yes	No
Stone Accumulation in the Bed	Potential Problem	No Problem
Washed Coal Desired?	Yes	No

Table 5

DIRECT AND INDIRECT COAL FEED SYSTEMS

	DIRECT	INDIRECT
Typical Application	Electric Utilities— P.C. Units	Industrial Stokers
Surge Bins?	No	Yes
Conveyor Capacity	Boiler Demand Rate	~10x Boiler Demand Rate
Coal Drier and Crusher (if any)	In-Line With Feed System	Free-Standing System

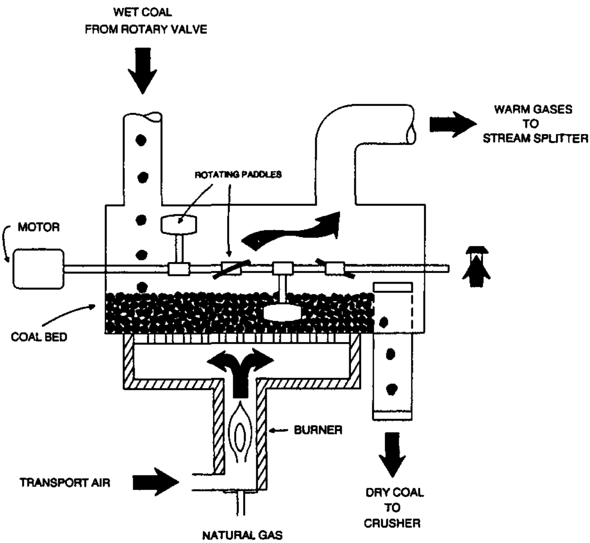


Figure 3

COAL DRIER

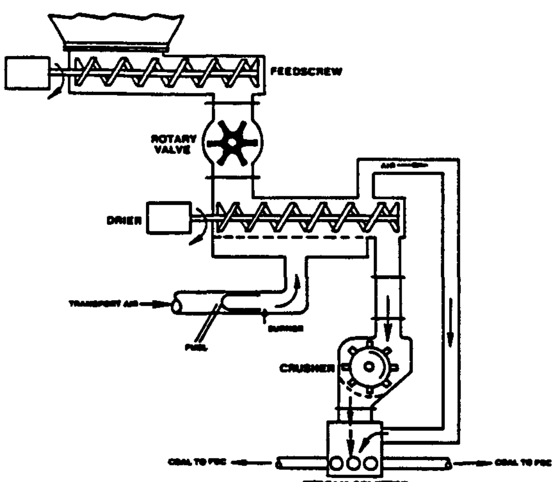


Figure 2
Coal Feed Train

Our stream splitter (figure 4) divides the coal into eighteen parts in a single stage.

3. The controls.

The problem with controlling the steam output of an FBC stems from the water tubes in the bed that are used for cooling. These tubes remove a relatively constant amount of heat, and if the fuel and air are reduced by more than 10 or 15% from the design point, the bed temperature cools below the point of most efficient combustion; further reductions will quench combustion altogther. As a result, early FBC's were built in modules, to be turned on or off individually, with only limited turndown from each. Modular control created operating problems, some of which are described in the literature.

More recently, it has been recognized that quite extensive continuous turndown could be achieved, of as much as 3 to 1, by locating the water tubes in the splash zone, or the region slightly above the top of the slumped bed's surface. As the airflow is increased, the bed expands, simultaneously providing more air for combustion and splashing an increasing amount of tube area. But to work, the settled-bed height has to be carefully controlled: in effect, both air velocity and the amount of material in the bed must be modulated. Air flow modulation is easy - it requires only the turning of the valve - but bed level control requires the removal of hot solids from the bed when less tube splashing is required, and its return when the opposite is needed. To date, limestone feed and removal systems have been used for this, but this procedure is both slow and noticeably wasteful of sorbent.

Our approach to this problem has been to use a storage bed to retain the unwanted bed material and return it when that is desired: by this method, no bed material is wasted. The storage bed itself is fluidized (by combustion air) whenever solids transfer is taking place, in order to smooth out the solids across the bed. To minimize the difficulty of handling hot solids, the storage bed has been located directly under the combustion bed (figure 1) with downward flow occurring by gravity through a simple standpipe, or downcomer.

The downcomer operates as seen in figure 5. By filling the standpipe with solids before the storage-bed air is turned on, the standpipe is always kept full of solids, even during operation, thereby acting as a pressure seal and preventing the upward flow of solids. The upcomer (figure 6), in contrast, is a pneumatic conveyor that allows solids to flow in the direction of pressure drop. Upcomer action occurs whenever the valve in figure 6 is opened. Since the solids in the storage bed have been cooled to about 300 degrees F by the flow of combustion air, upcomer flow is freed from the difficulties of handling hot solids.

4. Retrofit capability.

An existing boiler represents about a quarter of the cost of a coal-fired system; avoiding its premature obsolescence by the use of retrofitting is an attractive option. FBC's have a unique opportunity to retrofit coal boilers, and also boilers designed for gas and oil, because of the dry, non-sticky nature of FBC ash which avoids the

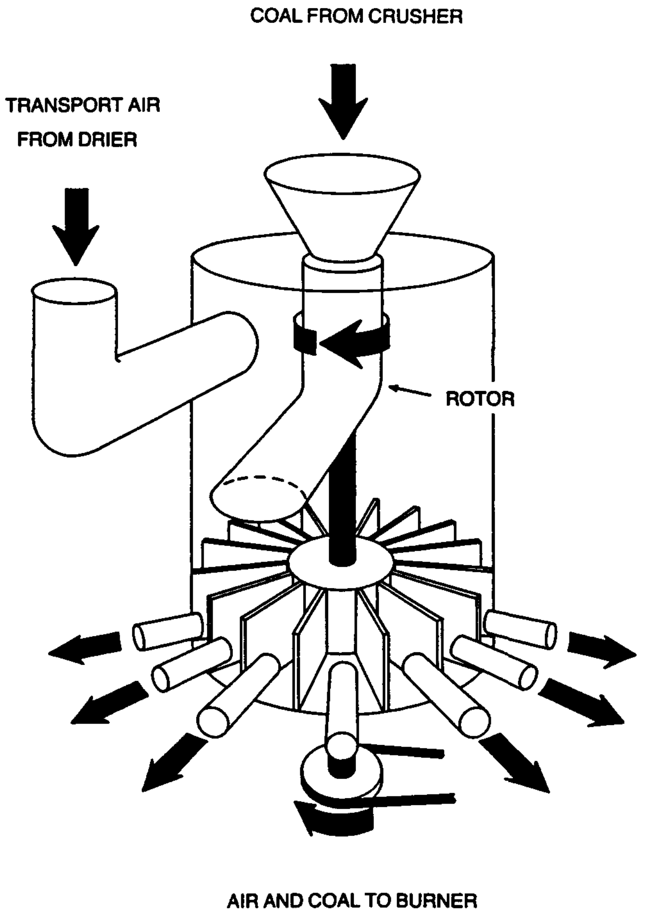
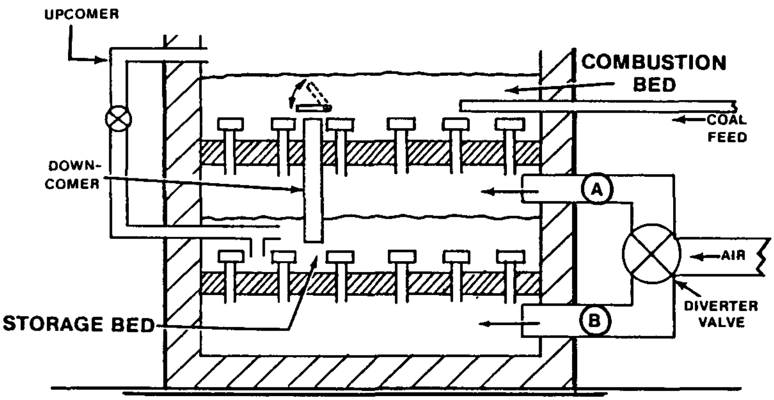


Figure 4

COAL STREAM SPLITTER



Step	Process	Airflow enters at	Valve
1	Downcomer Priming	A	Open
2	Downcomer Operation	B	Open
3	Normal Operation	A	Closed

Figure 5
Downcomer Schematic Diagram

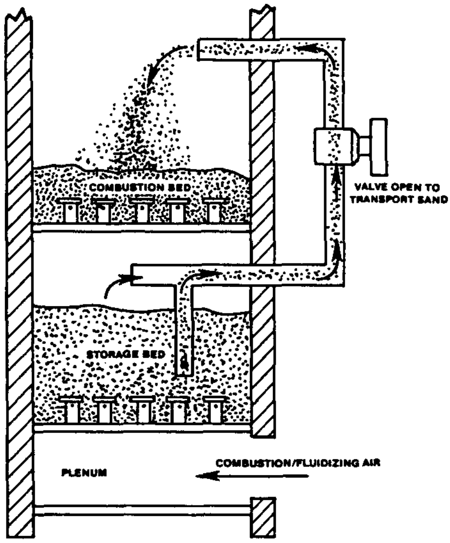


Figure 6
Upcomer Schematic Diagram

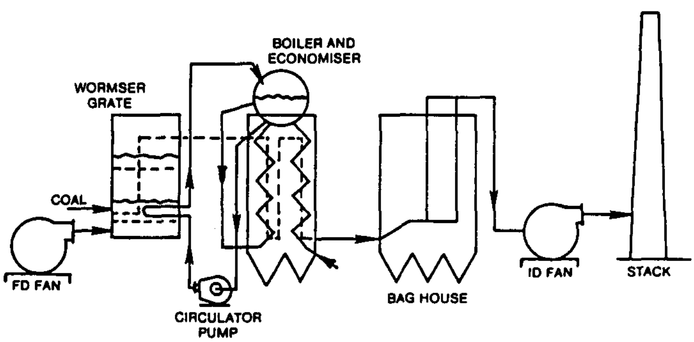


Figure 7
Simplified Flow Sheet of Wormser Grate

problem of tube fouling. But FBC's must be designed to meet the requirements of retrofit, including a remote coal han-dling system (for use in built-up areas), a sufficiently compact boiler (to fit in the existing boiler house) and a water circulation system that allows the FBC to operate in conjunction with the existing boiler. Wormser Grate has been designed to incorporate all of these features; see figure 7.

B. THE DEVELOPMENT OF THE WORMSER GRATE

So much for what we are trying to do; now the question is, are we actually doing?

The system at Iowa Beef Processor's, Inc. plant in Amarillo, Texas is the first full-scale commercial unit of a Wormser Grate. It follows on a development program started by the company seven years ago, whose milestones are identified in figure 8. A summary of the design parameters for the Amarillo unit are listed on tables 6 and 7. The history of the project is outlined in figure 9. A photo of the fluidized bed combustor is shown in figure 10. Some added design details are presented in references 1 and 2.

In sum, engineering studies for the project were begun in December, 1980 and the contract was let in July, 1981. The unit was completed and hydro-tested a year later, in June, 1982. July and August were spent at shakedown operations consisting of checking out of the subsystems. When this was done, the burner was fired successfully on coal in September; firing was for an hour, with voluntary shutdown.

There followed a four month debugging phase. During September and October, work was focused on the burner light-off system. At the beginning, light-off was time consuming - taking upwards of five hours - and uncertain; sometimes light-off never occurred. In addition, the insulation in the windbox failed where the preheat burners are located.

The windbox was reinsulated and the start-up procedure modified. We haven't had an aborted start-up since October and light-off routinely occurs in 1 1/4 hours.

In November and December, we worked on the coal feed system. At the outset, we experienced plugging in the coal lines - often within minutes of start-up - and in as many as half of the lines. The problem was attributed to moisture, which was driven to steam in the dr but then recondensed in the cold piping. The problem was solved new procedure that allows us to use the drier's burner to preheat piping before the coal flow is started. Since December, we've never had a recurrence of the line-pluggage problem.

By January, the burner was working well enough to operate daily and we could start to measure its responses to control changes. These were then used to set the automatic controls; by the end of the month, we were able to start, run and shutdown automatically.

Table 6
DESIGN CONDITIONS OF THE AMARILLO UNIT

Steam Flow	70,000 lbs/hour
Steam Condition	650 psig, saturated
Feedwater Temperature	220° F
Firing Rate	88,000,000 Btu/hour
Coal Rate*	10,110 lbs/hour
Bed Dimensions:	10 ft. x 17 ft.
FBC Height	14 ft. 3"
Combustion-Bed Temperature	1750° F
Desulfurizing Velocity	7.3 ft./second @ 1550° F
Unburned Carbon Loss*	3%
Excess Air	22%
Boiler Efficiency	80.6%

*TUCO Coal — See Table 7

Table 7

THE DESIGN COAL AND LIMESTONE SPECIFICATIONS

	LOW-SULFUR COAL	HIGH-SULFUR COAL
Coal Name	TUCO	Linn County
Source	Wyoming	Kansas
Type	Subbituminous	Bituminous
Size	2" x 0	2" x 0
HHV (BTU/lb.)	8700	11,300
Ash	5.0%	14.0%
Moisture	27.1%	9.0%
Sulfur	0.3%	4.0%
Volatiles	32.0%	32.0%
Sorbent Type	Dolomite,Lee J. Milligan Co.,Texas	
Size-Purchased	5/8 x 10 Mesh	
Avg. dia, as fed	1000 (14 Mesh-Tyler)	
Purity	55% $CaCO_3$	
Scrubbing With:	TUCO Coal	Linn Coal
SO_2 Removal	40%	90%
Ca/S	0.9	2.8
Sorbent Rate (lb/hr)	160	5000
Ratio, lb-sorbent/lb coal	.015	.65

Figure 8
Development of Wormser Grate

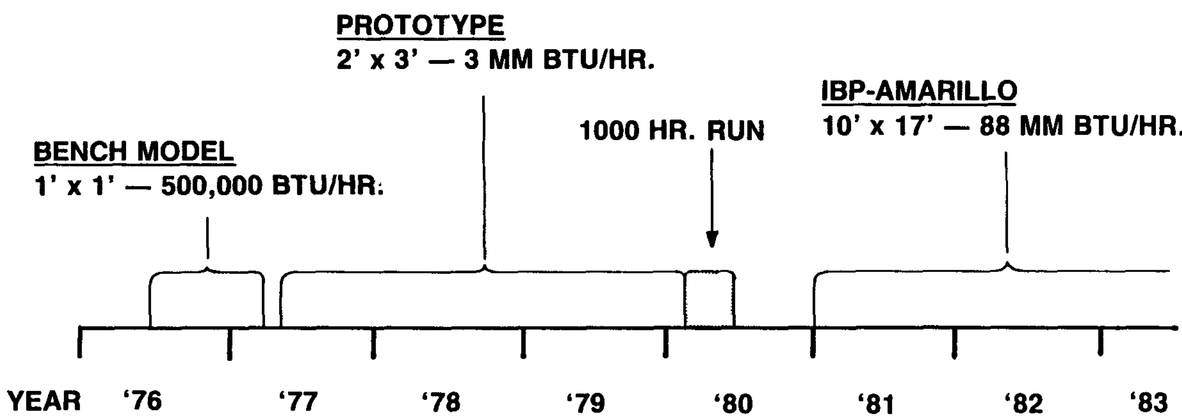


Figure 9
History of the IBP-Amarillo Installation

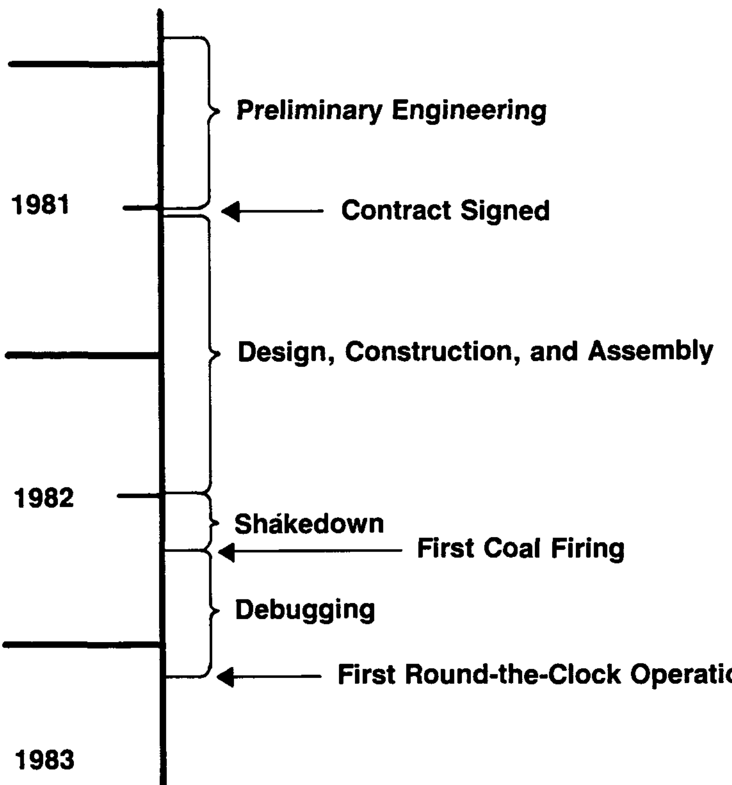
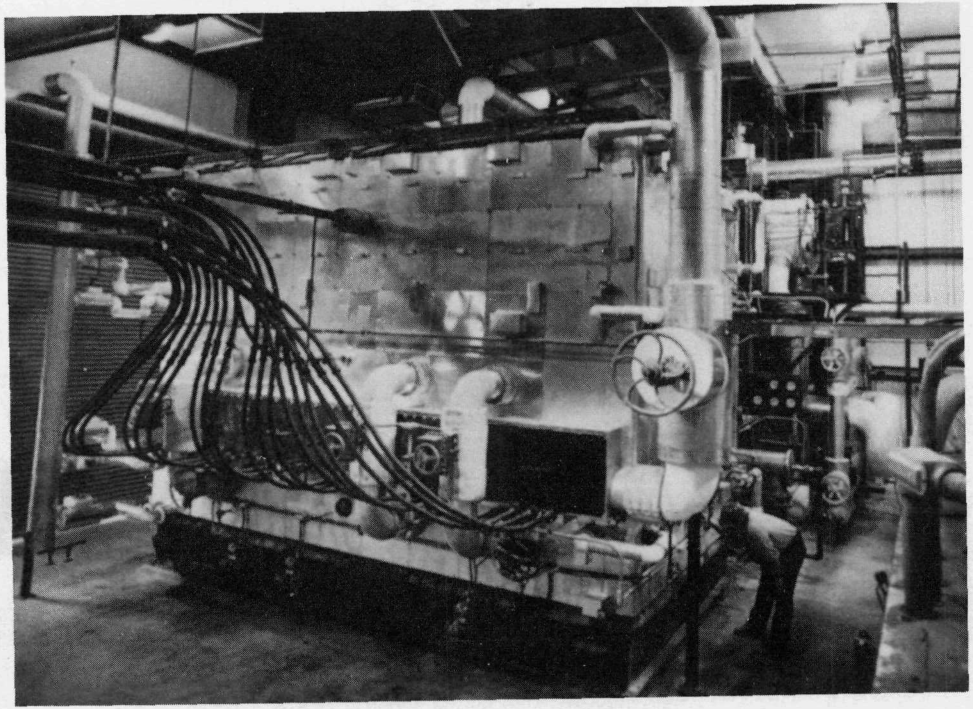


Figure 10

GRATE INSTALLATION AT AMARILLO



C. CURRENT STATUS

As of this writing, we are 300 hours through our 30 day acceptance test and are running 24 hours a day, 5 days a week. The burner is able to follow load changes automatically and over the expected range. Continuous operation is achieved to as little as 22,000 lbs./hr., or 31% of rated capacity. Below this, the burner automatically shunts to the cycling mode and returns to the continuous mode when the load increases. The speed of response is as expected: we've been able to follow load changes of 15% per minute while maintaining steam temperature within 10 degrees F and expect to be able to respond to 25% per minute load changes if required to. To date, we have operated to only 85% of rated capacity, as the new water treatment plant isn't finished and we are therefore pressure limited.

The availability has been excellent, running around 98%. During the 300 hours of the test, the only shutdowns have been those caused by tramp metal blockages in the coal screw, and one shutdown due to a glitch in the controls. Together, these shutdowns cost us four hours of down time. We are installing another magnet to reduce the former problem and think we've solved the latter. We also get occasional blockages due to tramp elements getting caught in the coal pipes, but these are infrequent - less than one blockage per 24 hours -and are fixed without burner shutdown by the judicious use of compressed air in the plugged line.

In fact, the Wormser Grate part of the coal feed system is more - trouble-free than that of the conventional coal feed system, supplied by others, used to get coal to our bin. To date, we've burned a very fine coal, with 90% minus 1/4" and high moisture (to 13%), as well as a very coarse coal (to 3" topsize). The former type caused some ratholing in the coal silo, and the latter, some problems of feeding through the dense-phase conveyor. Our coal system, we're proud to say, dealt with both types without a hitch.

At present, the plant is operated with two men per shift. One is our project engineer; the others are IBP's permanent staff hired to operate the steam plant. Only two of these have had boilerhouse experience and none has worked with coal before. IBP's expectation is that they'll operate with one man per shift, plus the supervisor, when the training program is completed in a month.

Performance measurements, though preliminary, are very satisfactory. Carbon monoxide is reading only 100 ppm at 20% excess air, indicating that the bed is being uniformly fluidized and that the stream-splitter is doing its job. SO2 scrubbing efficiency is over 90% with emission levels around 50 ppm. NOX emissions are unexpectedly low, around 100 ppm, or a fifth of current large-boiler standards. Particulate emissions are invisible to the naked eye at the stack, downstream of the baghouse. We are going to do these measurements more carefully, under the watchful eye of an independent testing laboratory, this month.

SUMMARY

Wormser Grate is now being offered with full commercial guarantees. Our second unit, a retrofit at the University of Lowell in

Massachusetts, is scheduled to be installed this winter. Stal Laval, the Swedish electrical manufacturer, has licensed Wormser Grate for use in Scandanavia and has sold a dual-bed FBC for a district heating plant in Sweden.

Of our original objectives, we've acheived a unit that is affordable and clean, and appears to be reliable. In short, we think we have a burner that works as it should.

References

1. "The Wormser Grate Installation at I.B.P.'s Plant in Amarillo, Texas", Alex Wormser, Walter Backwith, Seventh International Conference on Fluidized Bed Combustors, October 25 - 28, 1982, Philadelphia, Pa.

2. "The Wormser Grate Installation at I.B.P.'S Plant in Amarillo, Texas", Alex Wormser, Walter Beckwith, Fifth International Coal Utilization Exhibition and Conference, December 4 - 9, 1982, Houston, Texas.

INITIAL OPERATION OF CONOCO'S SOUTH TEXAS FLUIDIZED BED COMBUSTOR

Oscar Jones
CONOCO INC.
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SUMMARY

In its first year of operations, the Conoco Inc. South Texas Multi-Solids Fluid Bed Combustor (MS-FBC) logged over 4,900 actual operating hours. During that time, the MS-FBC had continuous runs of 30, 60 and 45 days.

As of February 1, 1983, operational reliability of the MS-FBC steam generator was such that the steamflood, for which it was designed was able to depend on it as its sole source of steam. The MS-FBC has replaced high fuel cost, oil-fired, protable steam generators which have historically been used to supply steam in the oil fields to support steamflood operations.

The MS-FBC has met or exceeded its design specifications including:

-- steam capacity, pressure and quality

-- sulfur capture and NO_x emissions

-- carbon burnup efficiencies

The only design objective yet to be achieved, is the overall thermal efficiency which appears to decline following each startup as the top rows of the finned tubes in the Economizer become fouled with fly ash. This efficiency decline can most likely be prevented by addition of soot blowers in the Economizer.

MS-FBC operations during the first year were carried out using two of the three design fuels. Most of the operating hours were accumulated on Laredo (cannel) coal. Approximately 30 days of operating time was logged in August and September, 1982, while burning a high sulfur petroleum coke containing over 7 wt. % sulfur.

Conoco considers the South Texas MS-FBC steam generator a technical and economic success. Its technical performance after one year is quite remarkable for a first-of-a-kind prototype unit. Furthermore, the MS-FBC is an economic success since its operation is resulting in a fuel savings of $5,000/day over a comparably sized oil fired steam generator.

BACKGROUND

The MS-FBC generates 2,450 psig, 80 percent quality steam for use in the pilot tar sands steamflood project. Steam is injected into the San Miguel 4 tar sands formation to produce a very heavy, -2° API gravity, tar. Conoco employs its proprietary FAST process to produce tar from this formation. The acronym FAST stands for Conoco's patented "Fracture Assisted Steamflood Technology" used to produce tar or heavy oil with minimum thermal energy input to the formation.

The South Texas Tar Sands pilot steamflood project using the FAST recovery process and the evaluation of the MS-FBC steam generator technology are funded and operated by Conoco's North American Production Department, Corpus Christi Division.

DESIGN BASIS

Conoco's South Texas MS-FBC has a design absorbed duty of 50 MMBtu/hr. It will generate 50,000 or 60,450 lb/hr of 80 percent quality steam depending on the temperature of the preheated feedwater. The steamflood operation requires steam pressures of 2,000 to 2,450 PSIG. Sodium zeolite softeners are used to provide soft water to the steam coils of the MS-FBC. Calcium hardness must be reduced to less than 1.0 ppm. By holding the steam quality to a maximum of 80 percent, the solids in the feedwater can be held in solution and are not deposited on the walls of the steam tubes.

One of the reasons for selecting the MS-FBC process is its adaptability for burning a wide variety of solid fuels or combustible waste byproducts. The Conoco MS-FBC and ancillary equipment are designed to burn any of three solid fuels considered potential candidates for long term use. All of the fuels considered are indigenous to the area minimizing transportation cost. The three design fuels are:

<u>Eagle Pass Coal</u>--high ash, low sulfur, low heating value

<u>Laredo Coal</u>--cannel quality, moderate sulfur, good heating value

<u>Petroleum Coke</u>--fuel grade, low metals and ash, very high sulfur, and excellent heating value

Use of all three fuels in the design basis has resulted in a very flexible and adaptable system. Some of the pertinent characteristics of the design fuels are shown in Table 1.

<u>TABLE 1 - FUEL CHARACTERISTICS</u>

	Laredo Coal	Petroleum Coke	Eagle Pass Coal
Sulfur, Wt %	1.50	7.08	0.64
Ash Content, Wt %	11.38	0.47	38.38
Gross Heating Value, Btu/lb	13,028	14,948	7,937

Limestone is used as the sorbent for SO_2 removal in the MS-FBC Combustor. Limestone fines are available from a quarrying and aggregate crushing operation located about 15 miles from the steamflood site. This particular limestone is unusual in that it contains 3-6 percent high sulfur tar similar to that produced by the steamflood operation. The limestone fines contain about 85 percent calcium carbonate and negligible amounts of magnesium carbonate. Its heating value, due to its tar content, is just about offset by the additional limestone required to remove the incremental sulfur introduced by the tar in the limestone. The reactivity of this particular limestone is classified as medium-high so it is quite well suited to the South Texas MS-FBC operation. Chemical composition of the limestone used is shown in Table 2.

TABLE 2 - LIMESTONE PROPERTIES

CHEMICAL COMPOSITION	Wt %
Calcium Carbonate	85.7
Magnesium Carbonate	0.9
Silica and Alumina	8.6
Iron Oxide	2.3
Combustible Carbon	1.4
Sulfur	1.1
	100.0

All of the solids input to the MS-FBC are fed without benefit of crushing or grinding. Solid fuels are fired as received in a broad size range from 1-1/2 inch lumps down to fines. The limestone used is normally 1/8 inch and finer. Not having to grind the fuel and limestone adds to the energy efficiency and simplicity of the process.

The MS-FBC is designed to remove 95 percent of the reactive sulfur contained in the fuel and limestone introduced into the combustor while limiting the NO_x emissions to 100 ppmv or less. NO_x emission are controlled through the use of staged combustion. Adequate sulfur capture has been assured by specifying a very conservative design calcium to sulfur ratio (Ca/S) of 4.5 to 1.0. Operations to date have confirmed that the 4.5/1.0 ratio is, in fact, very conservative.

Table 3 gives a tabulation of the pertinent design bases and assumptions for Conoco's South Texas MS-FBC.

TABLE 3 - DESIGN PARAMETERS AND ASSUMPTIONS

Absorbed Duty	50 million Btu/hr
Steam Pressure	2,450 psig
Steam Quality	80%
Carbon Burnup	95% (Min)
Excess Air	15%
Overal Efficiency	76.6%
Combustion Zone Temperature	1,650 F
Combustion Zone Pressure	-1.0 inch W.C.
Recycled Entrained Bed Temp.	1,100 F
Stack Gas Temperature	400 F (Max)

Limestone Calcination	90% (Min)
Ca/S Makeup Ratio	4.5/1.0
Sulfur Capture	95% (Min)
NO_x Emissions	100 ppv (Max)

MS-FBC PROCESS FLOW DESCRIPTION

*There are two unique features of the MS-FBC proces*s. The first is the use of a circulating entrained bed which serves as the primary heat transfer medium. The second is inclusion of a larger particle referred to as "dense bed material." A bed of larger diameter particles is maintained at the bottom of the Combustor to enhance mixing and residence time of the fuel and limestone. The following paragraphs discuss the pertinent operations relative to the MS-FBC operation.

1. Entrained Bed Circulation - Lighter particles, about the size of fine beach sand, make up the circulating entrained bed which is transported by combustion air from the Combustor through two parallel Primary Cyclones into the External Heat Exchanger (EHE). The Primary Cyclones are designed to collect 99.5 percent of the 1,650 F entrained bed material entering them.

Entrained bed material passes over the steam coil in the EHE and is cooled to 1,100 F prior to being returned to the Combustor for another cycle. The cooled entrained bed material is recycled to the bottom and to the middle of the Combustor under automatic temperature control with the split being determined by the heat release in the top and bottom of the Combustor. The EHE is gently fluidized at 1 to 1.5 feet/sec superficial velocity. This is in contrast to transport velocities of 15-30 feet/sec in the Combustor.

Conoco's MS-FBC Combustor is designed for "staged combustion" to spread the burning across the length of the Combustor versus having it all occur in a very narrow, high temperature zone at the bottom. By holding the peak combustion temperatures lower, conditions at which NO_x formation is favored are avoided. Air input to the Combustor is regulated so that only 40-45 percent of the stoichiometric air requirement is supplied to the bottom of the Combustor. The remaining combustion air is introduced as secondary air near the middle of the Combustor supplying oxygen necessary to burn any fuel carried out of the dense bed and to complete conversion of CO to CO_2.

2. Fuel and Limestone Feed - Fuel and limestone are added to the top of the Combustor bed using weigh belt

feeders and a combination gravity flow--pneumatically assisted transport. Coal, petroleum coke and limestone are fed as received without benefit of any size reduction. The fuel has a 1-1/2 x 0 inch size range with about 30 percent being 1 inch and larger. The limestone fines received are approximately 1/8 x 0 inch. Addition rates for all of the solids fed to the Combustor are controlled from a central control panel.

3. Steam Generation Loop - Feedwater for the MS-FBC is supplied at about 230 F having been preheated by exchange with the produced fluids from the steamflood operation. Preheated water flows through a single pass, finned coil in the Convection Section before entering the bare, single pass steam generating coil in the EHE. Heat input in the EHE produces saturated steam at about 70 percent quality. The steam makes a final pass through another finned coil in the Economizer where it is heated to 80 percent quality.

4. Flue Gas Cleanup - Flue gas leaving the Primary Cyclones is cooled from 1,600 F to 400 F as it passes through the Economizer. The cooled flue gas then flows through a single, unlined carbon steel Secondary Cyclone--the function of which is to protect the Baghouses from intermittent slugs of entrained bed material carried beyond the Primary Cyclones during upsets or pressure surges.

Residual dust in the flue gas is removed by four Baghouses arranged in parallel. Each Baghouse is equipped with 96 HUYGLAS bags which are 6 inches in diameter and 12 feet long. The Baghouse installation has an air-to-cloth ratio of 3.25 to 1 CFM/ft^2 when all four Baghouses are in service.

Stack gas emissions and combustion efficiency are monitored by continuous, online analyzers. SO_2, NO_x, and particulate emission levels are measured to demonstrate compliance with the Texas Air Control Board (TACB) operating permit. CO, CO_2, and excess O_2 are also measured and recorded continuously to assist the operator in optimizing combustion efficiency and to assure proper limestone calcination and sulfur dioxide capture.

5. Ash Removal System - Bottom ash residue (ash) is removed from the MS-FBC system at three points. Major withdrawal is from the EHE as an overflow to control the circulating bed inventory. A small quantity of ash is collected by the Secondary Cyclone. An Ash Reinjection Blower was provided to return Secondary Cyclone ash to the Combustor if necessary to recycle unburned fuel. Normally, ash reinjection is not required. The third and smallest ash removal point is the 10-50 micron fly ash collected by the Baghouses.

OPERATING EXPERIENCE

1. Startup - Startup of the MS-FBC requires that a dense bed layer be established in the bottom of the Combustor very early in the procedure. The refractory linings of the major items of equipment are very large heat sinks and must, therefore, be heated very slowly during startup. Startup heat is supplied by an oil-fired air preheater capable of heating the Combustor to about 900 F in 8 hours.

As the equipment is heated during startup, a temporary entrained bed of clean, dry, closely graded 40-70 mesh foundry sand is added to the unit to establish solids circulation between the Combustor, Primary Cyclones, and EHE. Once a good working level of sand is established in the EHE and the system temperature is around 850-900 F, coal can be fed to the Combustor.

2. Initial Operating Period - Initial Operation of the MS-FBC was on Laredo coal since the Eagle Pass coal, which is the economic fuel of choice, is not yet available in commercial quantities. Laredo coal burns well and has a moderate sulfur level so it was a logical startup candidate because of the proximity of its source to the MS-FBC site.

Operation of the MS-FBC was at half rate through the months of January, February, and March of 1982 while various mechanical problems with preengineered ancillary equipment packages were being resolved.

Following the 3-month equipment and instrumentation "shakedown" period, it was decided to shutdown the MS-FBC for a thorough internal mechanical inspection and to make all of the known repairs and/or modifications considered necessary at that time.

Inspection of the MS-FBC internals showed very little erosion or corrosion of the piping in contact with the circulating bed. This included the 310 ss. air distributors in the bottom of the Combustor and the carbon steel high pressure steam coils in the EHE and the Convection Section. These were found to still have full thickness.

Further inspection showed scattered erosion in some of the refractory-lined entrained bed circulation lines where velocities were high or turbulence was induced by the geometry of the ducts.

The inspection turned up one surprise. The refractory lining of the Primary Cyclone barrels had failed due to excessive thermal expansion of the refractory hexmesh support. It is speculated that the hexmesh did not have sufficient anchor points to the shell considering the operating temperature differential and the large diameter of the cyclones.

3. Post Startup Modifications and Repairs - During the April 1982 shutdown and inspection, several modifications were made to the MS-FBC to improve its operability and reliability. These included:

a. Addition of a third circulating entrained bed duct to return cold material from the EHE directly into the combustion zone just above the dense bed. Its purpose was to speed startup heatup rate, provide greater heat removal capacity per unit of circulating entrained bed, and reduce the circulating bed mass rate.

b. Rebuilding of the Startup Preheater to speed startup and improve reliability.

c. Replacement of dense bed and startup sand slide gates which were prone to bind.

d. Piping the blowers for series flow to provide higher pressure for the primary air supplied to the reducing zone of the Combustor.

e. Redesign of the refractory lining of some of the entrained bed circulation ducts in areas suffering greater than expected erosion rates. In some places, usually at turns, junctions, or entrances where erosion was high, it was necessary to replace the cast refractory with high alumina firebrick like that used to line the Combustor.

f. The damaged refractory in the Primary Cyclones was replaced using an improved refractory anchoring system.

4. More Recent Operating Experience - Following the shutdown in April, the unit was started up on Laredo coal for a series of performance tests. After these tests, which indicated that the MS-FBC would meet its design requirements while burning Laredo coal, burning of high sulfur petroleum coke was started in late August. Burning of coke has been very successful. The unit was still able to remove 95 percent plus of the input sulfur. The only noticeable difference, other than the obviously higher limestone requirements associated with burning petroleum coke, was that the combustion temperature was 50-75 F higher than that required to burn Laredo coal.

A constant threat to continuous operation of the MS-FBC has been frequent power interruptions because of the remoteness of the location. Fortunately, most of the outages last only a few seconds. Stoppage of all of the electrically driven equipment causes the fluidized beds to slump and transport of entrained bed to cease. It is a remarkable testimony to the flexibility and resiliency of the unit and the operators that they are usually able to restart the equipment and have the operation lined-out again in an hour or so. These power interruptions have averaged about three per week since startup.

As equipment problems have been resolved, the service factor of the MS-FBC has continually improved. The MS-FBC has logged continuous runs of 30, 60 and 45 days despite power failures and a lack of standby equipment.

CONCLUSIONS

Conoco's objective in conducting a prototype test of the MS-FBC was to develop a process which could burn a wide range of low quality solid fuels in place of oil or gas to generate the steam required to produce the extensive tar sands reserves in South Texas. After 12 months operation of the MS-FBC, we believe that the Battelle/Struthers Thermo-Flood circulating bed MS-FBC steam generator has proven itself under commercial field conditions. The South Texas prototype test has been an unqualified success. We are confident that the circulating bed concept embodied in the MS-FBC makes it readily adaptable for scale up to commercial size installations by factors of five to eight times the size of the prototype unit. Several units in that size range would be required for a central steam generating facility to provide the steam required by a 5-10,000 BPD steamflood operation.

The Conoco MS-FBC has met or exceeded all of its design requirements. It has demonstrated the capacity to burn a range of solid fuels having sulfur contents from 1.5 to 7.1 weight percent while operating for extended periods at design conditions. The MS-FBC steam generator also has demonstrated good control response to upset conditions such as electrical power interruptions or partial loss of fuel or limestone feed.

During its first year of operation, the MS-FBC has demonstrated that:

a. It can burn coal or petroleum coke in a size range of 1-1/2 x 0 inches.

b. It is able to remove in excess of 96 percent of the sulfur in the fuel using Ca/S ratios as low as 3.0/1.0.

c. Carbon burnup efficiencies of over 97 percent are readily attainable.

d. Staged combustion is very effective in holding NO_x emissions to less than 100 ppmv in the flue gas.

e. The circulating bed offers the advantages of improved fuel and limestone utilization while making it possible to operate without having the steam coil in the erosive environment of the Combustor bed. Erosion of the carbon steel steam coils has been negligible.

f. The multi-solids, dense bed design permits overbed fuel and limestone feed eliminating the need for a complicated underbed feed system.

g. Use of conventional high alumina refractory and brick linings can effectively control erosion by the circulating entrained bed materials.

h. The MS-FBC steam generator system responses and process control systems required to operate the unit are simple and pose no unusual control problems.

i. The continuous process analyzer package specified and developed by Conoco to monitor stack gas emission levels has evolved into a useful and reliable system.

The successful operation of the Conoco MS-FBC in South Texas has been confirmed and duplicated by Struthers Thermo-Flood's 5 million Btu/hr MS-FBC test facility in Winfield, Kansas. Having both units in operation simultaneously made it possible for Conoco, Battelle, and Struthers Thermo-Flood to speed up the learning process in further developing multi-solids fluid bed combustion technology.

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ECONOMICS/RELIABILITY TRADE-OFFS IN MATERIALS SELECTION FOR ELECTRIC POWER GENERATION PROCESSES

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ABSTRACT

Energy and/or the predicted lack of it has been the number one problem of the United States since the Arab oil embargo of 1973-74. It has been established that the technical solution of the energy crisis is very much dependent upon the development of new and in some cases the availability of materials. Successful development of most coal conversion processes as well as the increased availabilities of the currently available technologies somewhat depend on the capability of materials to withstand many adverse conditions.

Although the rate of energy growth has been falling consistently during the last five years and currently forecasted to be much lower than previously predicted, the growth rate for electrical energy is still expected to remain relatively high and grow at a rate twice that of the total energy growth rate. Because of the high cost of capital (i.e. high interest rate) and current economic condition, the utility industry in general, is not in position to design and build new power plants - either fossil or nuclear - to satisfy the electric power demand beyond 1980's. Hence, a brand new trend is just beginnin to surface its way that deals with the increased reliability and availability of the existing power plants. The preliminary analyses show that it could be possible to increase the availability of existing plants considerably by maintaining a materials maintenance program and judicial selection (or replacement) of materials.

However, a strong supporting materials evaluation program is needed to provide durable and more reliable system that will ultimately reduce the cost of electricity

production. The economics/reliability trade-offs in materials for improving availability of conventional coal-fired plants along with various advanced coal conversion and utilization processes for electric power generation need special attention. If this approach is successful, the entire area of utility planning including reserve margin requirement (and hence building additional capacity) would change, saving billions of dollars that otherwise will force to increase the cost of electricity much faster than the general inflation rate.

INTRODUCTION

The basic problem of generating electricity or any other secondary form of energy is its cost and the priorities given to its sources, rather than any absolute limit on its availability. The technical solutions to the energy crisis are completely dependent upon the availability of materials. On one hand we must develop methods to use high-sulfur coal with greater efficiency. On the other hand, air pollution regulations are being enforced more stringently today than ever before. In order to conform with these higher control standards and to avoid problems with regulatory agencies, the utilities must control or eliminate pollutant emissions. These regulations are forcing the utilities to use electrostatic precipitator and/or baghouse to remove extremely small size of particles ranging from 0.1 to 1 micron in diameter. Shortly flue gas scrubbers will be necessary to remove SO_2 to satisfy the environmental standards.

A modern 1300 MWe Station firing up to 13,000 tons (12,000 t) of coal per day generates flue gas containing several thousand tons of fly ash per day. Even with a 99% efficient precipitator, more than 17 tons (15t) is emitted daily from the stacks. It is estimated that the electric utilities will spend more than $5 Billion between now and 1985 on equipment to meet the particulate standard. "Fabric filters" seem to promise to be highly efficient for particulate control. The high density ionizer now being developed under Electric Power Research Institute contract could be commercially available within the next few years. Based on the current accuracy of date, the ionizer could save utilities 70% in capital spending on retrofit installations and 30% on new units.

However, we must look for other advanced methods for utilizing our vast deposits of coal in an environmentally acceptable way. In the nuclear area the lack of proven means of storing radioactive wastes continues to hamper public acceptances of nuclear energy.It must, however,play an important role towards our total energy requirements. Some of the answers to our near-term energy problem lies in the breeder reactor, alkali flue-gas desulferization along with fluidized-bed technology, low and medium Btu gasification processes and magnetohydrodynamics (MHD) power generation. All these hold promise to solve sulfur dioxide emission problems without the addition of expensive and somewhat unproven, unrealiable scrubbers. Their eventual success depends, however, on the availability and development of materials. Recent work on new materials for such applications by EPRI and the laboratories around the world look promising.

We have very little understanding of the basic problem of corrosion. Different metals and alloys react differently. It is obvious that the corrosion process will be the most serious problem for coalburning systems such as fluidized-bed, magnetohydrodynamics, and other advanced power generation schemes. Corrosion will limit the lifetime of boilers, heat exchangers, superheaters, ducts, valves and piping systems. Further, because of molten slag in the MHD system, a completely new problem to utilities-hot corrosion will be of great concern.

The interdependence of materials and energy is extremely strong. In fact, the development of any of the world's new energy systems will make unprecedented demands on heat resistant and corrosion resistant materials. These energy systems will thus provide a great challenge to the engineers in specifying materials.

CONVENTIONAL FOSSIL ENERGY SYSTEMS

Corrosion and stress corrosion cracking (SCC) are two most important problems in the conventional system. Fortunately enough, most of the problems can be overcome by the prudent selection of materials.

Materials for Steam Turbine

Large steam turbines used in central station power generation equipment are essentially giant energy converters which take steam from a fossil boiler or a nuclear steam generator reactor at temperatures of 1000°F and pressures as high as 3500 psi. The steam is expanded through several series of stationery nozzles and rotating buckets and finally discharged to a condenser where the steam temperature is close to ambient temperatures. The important characteristics include reliability, availability, initial cost of equipment, and the time and expense necessary to maintain it. The effective utilization of moderately high strength steels, whose properties are enhanced by heat treatment and that can withstand correspondingly higher stresses in the design and construction, has made it possible to build a modern large steam turbine. However, there are a number of instances of SCC in turbine components. This seems to be a problem area and needs additional attention.

Stress corrosion cracking is a result of a combination of tensile stress, material property and a corrosive environment. It is brittle in nature and may be both intergranular and transgranular depending on the material and environment. The most distinct feature of SCC is brittle failure at stresses substantially less than those necessary to cause failure in normal environment. The traditional methods of solving SCC problems are to eliminate the chemical contaminant in water, reduce the stress level and/or select a material either not or less sensitive to this phenomenon. The last alternative suggests avoiding high strength steels which are usually more susceptible to SCC.

In some applications the use of stronger steels and higher stresses are necessary from the economic standpoint. In some turbine components, however, there are instances where the added section cannot be tolerated and hence stronger material is the only solution to the design problem.

In such areas as bolting, bucket and rotor, heat-treated steels are necessary because annealed steels have relatively low yield strength that limit the tightening stress. In case of turbine buckets, increasing the cross-section to accommodate lower material strengths will increase the centrifugal stress applied to the buckets and increases the load that must be carried not only by the bucket attachment but by the rotor as well. In rotor forgings increasing the length of the rotor between the bearings to distribute the load imposed by the buckets is generally not permissible because of its influence on flexibility, unfavorable effects on critical speeds and other essential design parameters.

However, the most catastrophic failure by SCC occurs in the (L-1) and last stage of turbine blades. They could be replaced by titanium blades without degrading the turbine efficiency. Titanium has similar fatigue strength as high strength steels. A reliable stress vs. time-to-cracking curves for variety of materials used in turbine construction supports the substitution of high strength steels by titanium.

Rare but catstrophic turbine and generator explosion in rotors seems to be a nagging problem to the utility operators. This is usually due to the inherent defect due to rotor forging rather than the material itself. The recent advancement in electroslag melting (ESR) produces ingots almost defect free. However, these are correspondingly more expensive than conventional material. The rotor forgings made of Ni-Cr-Mo-V steel seems to be promising.

High Pressure Feed Water Heater

Copper-Nickel and Nickel-Copper alloys are most widely used for this purpose. These alloys usually fail through stress corrosion cracking. However, the change in manufacturing procedures has made it possible to achieve these materials that are highly resistant to SCC. The peaking service typically involves operation for about 12-15 hrs. per day, 5 days per week. These units are shut down completely during early morning hours, weekends and holidays and during operation they are subject to considerable variations in load. Because of free oxygen pick up during each start-up and shut-down cycle, considerable increase in the number and frequency of leaks due to corrosion is observed. (This is substantiated by the fact that the scale of the feed-water heater tubes are mainly copper and nickel oxides in about the same proportion as the base metal). However, the substitution of MONEL alloy 400 has almost eliminated these problems. Currently over 75 million feet of MONEL alloy 400 tubing is in service for feed water heater in this country. To justify the use of MONEL 400, a minimum service life of 20 years is required and such lives are not uncommon. The reason of economic advantage of MONEL alloys are - their superior strength and extremely favorable thermal conductivity. Because of these alloys higher yield strength (55,000 psi at room temperature for 0.2 percent offset), thinner walled tubing can be used with higher thermal efficiency. Moreover, MONEL 400 is immune to SCC in almost any environment that it is likely to be encountered in utility service. Even for U-bent tube bundles it is not necessary to stress-relieve the bends.

The review of the utility service experience confirms that copper-nickel tubes provide reliable service in both base-load and peaking service. Usually SCC failures are not very profound in any re-stress-relieved bends and/or low residual hoop-stress tubing even in the presence of corrodents from the water treatment. However, all copper-nickel alloys including MONEL 400 are found to be susceptible to SCC in ammonia under utility operating conditions.

Scrubbers (Flue Gas Desulfurization)

Plain carbon steel and Type 304 stainless steel generally corrode at an unacceptable high rate in scrubbers but type 316L with Molybdenum level of 2.75% or higher provides the best compromise between corrosion resistance and cost. It is generally resistant to SCC, pitting and crevice corrosion. Good design, conscientious maintenance and, in particular, regular removal of scale deposits insure its good performance. Type 317L looks even superior in pitting and crevice corrosion resistance because of its higher alloy content - especially molybdenum.

Deposits on alloy surfaces can cause problems. They act as hosts to acid and chlorides and can allow them to concentrate to such high levels that protective corrosion films usually break down. This localized corrosion may occur even though bulk values of pH and chloride indicate relative immunity from attack. More highly alloyed materials in the Fe-Ni-Cr-Mo system would resist most of the aggressive environment.

Dew point attack is another problem with SO_2 scrubbers. A highly corrosive environment can condense out in the down stream sections if the gas temperatures are lowered. Only nickel-base alloys containing appreciable amount of molybdenum can withstand this environment. The mist carried over from the scrubber can be saturated with acid vapor that initiates corrosion in the ducts and stack liners. The actual corrosion loss will be a function of pH value of the mist. Utilities are currently turning to either more expensive high alloy steels or reinforced plastic liners that are cheaper but have very low resist-
flue gas reheating over sulfur dew point so as to evaporate the mist carried over from the scrubber and eliminate or minimize downstream condensation. But from economical standpoint the prospect of reheating the flue gases from the outlet of wet scrubber is certainly not attractive by any means; however, the use of heat pipe heat exchanger to perform this duty - a devise that does not require any additional power - is quite attractive.

We, at American Electric Power, have been currently involved in a program which will test the corrosion resistance property and life expectancy of various materials from carbon steel with coatings to Hastelloy C-276. If the results of this program prove successful, a full size heat pipe reheater could be built and operated by 1980 eventually saving millions of dollars in materials cost.

Currently at various stages of development and commercial use are the improved high-Cr ferritic stainless steels or superferrites. These steels have the advantage over austenitic stainless steels in SCC resistance, and are considered to be used for condenser tubing for brackish and sea water, organic acids and caustic environments. Types 430 and 434 stainless steels do not undergo SCC even when stressed above the yield points in the environment usually found within the utility system such as chloride solution or calcium nitrate and caustic soda. Increase in chromium and molybdenum content or both for high purity single phase ferritic stainless steels increase their resistance to crevice corrosion in chloride environment. 25 or 26% Cr is immune to crevice corrosion even in high concentration of chloride that are not usually found in utility systems. However, the carbon content in these materials must be as low as 0.007% and hence, may not be economical to use.

MATERIALS FOR NEW ENERGY SYSTEMS

Direct or Indirect Coal Conversion Processes

In both direct and indirect conversion processes, combined effect of erosion and corrosion under oxidizing and reducing conditions, sulfide corrosion, hydrogen embrittlement and chloride reaction must be considered.

These processes for the conversion of coal to clean gaseous fuels usually operate at high pressures (P>60-65 atm.) and temperatures (T>1000-1500^oC) and involve aggressive environments containing H_2S, SO_2, NH_3, CH_4 and H_2O. These conditions place stringent demands on materials of construction for containment of these processes. Additionally, the economic viability of full scale plants is largely dependent upon long-term, safe and uninterrupted operation.

Considerable attention is necessary for such potential problems as erosion in the coal preparation system, transport lines, valves, cyclones along with corrosion and stress corrosion in the gas clean up and separation area, and the handling facilities of chars, slags, and other solids.

The electric utility companies have extensive experience in dealing with the problems of handling dry solids and low-viscosity slurries. Different characteristics are desirable in materials for resistance to different type of abrasion or erosion. Most of the commercial alloys that can withstand erosion are usually hard and hence their toughness and resistance to stress corrosion must be carefully considered.

Erosion of commonly used 310 and 316 stainless steel in combustion gas atmosphere at 975^oC is highly predominant. Little or no information exists on the behavior of the metals and alloys when subjected to solid particles at elevated temperatures especially in severely corrosive atmosphere. Such conditions are cause for serious concern in coal gasification systems. Before these processes are commercially utilized, data covering a range of different conditions are needed both for the purpose of materials development, selection and for the establishment of design criteria and increased reliability and availability of the various components.

Fluidized Bed Combustion

An improved understanding of the complex problem of hot corrosion and erosion in highly corrosive environments is needed for the effective use of metals and alloys in both Atmospheric and Pressurized Fluidized Bed Combustion Systems. So little is known about the combined effects of hot corrosion and erosion that it should be effectively analyzed from the thermodynamic equilibrium point of view.

In the fluidized-bed combustion system, the internal components may see different temperature regimes: In addition to high temperature exposures, various internal components and especially the heat transfer surfaces may face severe wear and corrosive effects in the fluidized bed. High bed temperatures resulting from periodic fluctuation, localized hot spots, or loss of coolant result in excessive creep rates. The erosion of the heat transfer surfaces is a function of particle shape, size, velocity, hardness, impact angle and tube arrangement. At maximum fluidizing velocity of 7 fps in PFBC bed, the ash particles formed at the low combustion temperatures are usually soft. Even with soft ash, erosion of tubes immersed in the bed may be severe.

Different alloys in a fluidized-bed burning coal are also exposed to a corrosive environment. Corrosion occurs primarily by chemical attack due to surface oxidation, removal of the protective scale on the metal surface through chemical reactions with corrodents, and direct chemical attack on metal surfaces. The most detrimental contaminants are the alkali compounds, chlorine and sulfur in coal.

The corrosion rate of in-bed tubes is a function of operating variables such as temperature fluctuations, fluidizing velocity and coal feed rate. The mechanism of material removal due to erosion-corrosion interaction has not yet been thoroughly understood. A basic research approach is necessary to gain understanding of the dominant mechanism of material degradation so that either alternate materials can be selected or the directions for improvement in existing materials can be specified. The reliability and availability of the fluidized bed processes will depend on how the materials behave under these environments.

In combined cycle concept (gas turbine & steam turbine), the erosion and/or fouling of gas turbine vanes and blades, perhaps complicated by hot corrosion, will be most severe and single most important problem to solve.

Alkali metals which are introduced into the bed with the coal and dolomite will be transported through the system in fine particulate ash and as vapor species which are in equilibrium with solid alkali metal-containing compounds in the bed or in the hot-gas particulate clean-up equipment. Because of the gas/solid equilibria, it may not be possible to prevent unacceptably high level of alkali metals from enternig the gas turbine even if all the particulate matter is removed from the gas stream. This may eliminate or reduce erosion to an acceptable limit. But hot corrosion that seems to be more deleterious at the operating range cannot be eliminated or reduced by tertiary clean up system. The presence of high levels of potassium and chlorine in the combustion produc from a PFBC creates the potential for further acceleratio of corrosion on gas turbine parts over and above that due to high-alkali flux. Potassium does not simply substitute for sodium in the corrosion phenomena, but significantly increases the rate of corrosion. Alkali chlorides are important in hot corrosion in that not only do they increase the corrosion rate in combination with sulfates, they usually attack the cobalt base alloys more vigorously than nickel base alloys. In conventional gas turbines where condensed chlorides are generally not present in deposits, the cobalt base alloys are the most resistant materials to corrosion attack.

The recent developments in sintered silicon nitride and silicon carbide (ceramics) suggest the possibility that these materials, with their greater erosion, corrosion and thermal shock resistance, may be candidate materials for the high-temperature inlet stages of turbine blades, burner, nozzles, etc.

Once the materials are selected, the thickness of tube, plate, etc. is calculated by ASME Code requirements. The thickness usually does not take into account any metal loss due to erosion and corrosion caused by actual operating environment. For application of tube materials at high temperatures and/or corrosive environments, where metal loss is expected through oxidation, sulfidation and/or erosion it is essential that a reasonable allowance for metal loss be added to the calculated thickness value. The total maximum acceptable metal loss rate on the fireside corrosion for most boiler tube materials has been established, based on operating experience. The corrosion allowance for these materials for PFBC application will probably be different but these data seem to be a good starting base. However, the subjects of erosion and corrosion behavior of commercially available boiler tube materials in PFBC environment should be thoroughly made.

At increasingly higher temperatures, the metallurgical and mechanical properties such as transformation and hardening, sensitization, carburization, temper embrittlement and grain growth, creep and stress rupture properties, fatigue strength and fracture toughness characteristics have to be accurately established. To withstand the high temperatures encountered within the fluidized-bed, to conserve heat and to increase process efficiency, the combustion chamber and possibly the gas cleaning systems (cyclones) have to be refractory-lined. Both castable and shaped materials should be considered and evaluated for economy and reliability.

Problems associated with refractory materials in PFBC are: leaching out of silica materials by moisture, carbon disintegration of fire clay brick in presence of carbon monoxide, destruction of alumina silica refractories by alkalies, erosion and abrasion by particulates and thermomechanical failures resulted from localized hot spots.

To resolve these problems refractory linings of two or more layers could be considered. The layer next to the shell could be insulating material over which an erosion resistant castable material should be used. Cooling coils may also be considered.

The ultimate success of the PFBC depends on the availability of materials. The challenge to the materials community is to improve reliability and decrease costs of process equipment. Many materials research and development programs are currently underway and many new programs have to be instituted. More interdisciplinary action between the materials community, management personnel and designers must be implemented. Especially needed are resolutions of material problem areas where operating conditions are new and unique but so severe that they exceed satisfactory performance of materials currently available and/or economical.

Materials for Coal-Fired MHD Power Generators

The strong national incentive to produce electricity from coal obviously gives a boost to magnetohydrodynamics (MHD) development. The cost of electricity (COE) for a number of energy conversion systems, based on fossil fuel, established that the coal-fired MHD-steam combination has the lowest COE, MHD power generation is based on the direct conversion of heat to electrically conducting fluid through a magnetic field. The attractiveness of MHD stems from the fact that the thermal energy in a gas or liquid is concerted directly into electric power - without the need for a turbine or rotating generator. The absence of any moving parts in contact with the hot working fluid simplifies the system and permits the higher temperatures to be used which results in higher plant efficiencies. A fossil fuel such as coal or char is burned in preheated and/or oxygen enriched compressed air to produce a temperature in the range of $4500^{\circ}F$-$5000^{\circ}F$. The hot gas is seeded with an easily ionized element, such as potassium, to increase its electrical conductivity. The seeded gas is then allowed to accelerate through a nozzle. Thus, the essential difference between an MHD generator and a convenient turbine-driven generator is that in the MHD generator the rotor is replaced by a high velocity, ionized working fluid. The inter-action of this high temperature conducting fluid with a strong, transverse magnetic field induces an electromagnetic field approximately proportional to the product of the square of velocity and magnetic field.

Regenerative heat exchangers are required to preheat the combustion air supply to at least 2700°F in order to achieve combustion temperatures of up to 4500-5000°F. This high temperature operation together with the addition of highly corrosive potassium salt creates enormous materials problem. Many of its materials and technical questions for MHD-Steam Power plant cannot be answered from the existing experimental facilities, because they are too small to be used for extrapolation to larger size. The success of the whole MHD process depends on the availability of materials and their performance.

Critical Components for MHD Power Generation

Materials selections for each component must be evaluated against operating conditions, life prediction, cost and availability, method, cost and time required to replace failed components, etc. The critical components that need special considerations are:

High-temperature air heater, combustor, nozzle MHD generator that includes electrodes, insulator, invertors and superconducting magnet, etc., radiant boiler, seed separator and/or reheater and low-temperature air heater and heat-recovery components.

At present there are no commercially available refractories which may survive at 3200°F in slagging conditions (oxidizing and reducing atmospheres). Hence, direct-fired air preheater should not even be considered for first generation. However, refractory at 3200°F in *non-slagging condition may be commercially available during* 1980's. The intensive literature survey shows that the high-alumina refractories under the condition may not be adequate. Magnesia-alumina spinel is a better choice, though creep and sintering may lead to failure at 3200°F. The thermal shock characteristics are not good but may be acceptable.

The combustor must be ceramic-lined, water-cooled type to withstand temperature as high as 3200°F. The highest temperature of the plasma will be over 5000°F and the *combustion gases will be under reducing conditions.* Zirconium oxide based materials may not be adequate under seed-slagging conditions but the alumina-chrome materials may be suitable at 3000°F or above. Low cost metals or alloys like carbon steel may be permissible provided that the tubes are protected with refractory at temperature 600°F or lower. However, corrosion of metals and alloys must be considered in selection under reducing conditions.

The material considerations for the nozzles are probably the most confusing at the current state of development. We may have to consider ceramic lining for improved s adhesion. However, less expensive refractory with metals cheaper than copper may serve the purpose. The performance of thin ceramic coatings (that is the present way of thinking) placed on metals is an uncertain area and should be further evaluated before designed for pilot and/or demonstration project.

The materials selection for MHD generator still remains an area of great uncertainty. A decision has to be made on the type of electrodes such as metal versus ceramic and cold wall versus hot wall. The operating conditions must be established very accurately. Boron nitride for cold wall and magnesia-alumina compound for hot wall insulators seem to be a good choice from preliminary analysis. Grooved metal electrodes with a refractory filling seem to work good for slag adherence. Satisfactory operating life under generator conditions has yet to be demonstrated for various electrodes. Electrochemical attack in slagging systems is a severe problem and has not yet been resolved at elevated temperatures. The U.S.-U.S.S.R. joint cooperative program on MHD could have resolved many of these problems before the demonstration plant is in final design stage.

In case of the diffuser, very inexpensive materials should be considered for water walls if the temperature is 700°F or below. At about 1500°F, corrosion by seed-slag mixtures may be excessive for zirconium oxide based materials to be considered for refractory linings but spinel ($MgAl_2O_4$) may serve the purpose. However, the refractory-slag interface temperature and the other operating conditions must be well defined.

Croloys with high chromium refractories (at temperatures 2800°F or above but metal temperature not above 800°F seem to be the preferred materials for radiant boiler. Their performance under high temperature and reducing conditions with high potassium levels has not been thoroughly investigated.

Currently available cyclone separators constructed with Hastelloy-X and Inconel-601 may not perform satisfactorily at 2150°F (or above) in a high potassium environment. Refractory-lined cyclones may be the best way to go, though the type of refractories that can withstand these environments have not yet been established.

The recent technological advances have reduced the magnet problem to manageable proportions even though additional material problems for superconducting magnets still exist.

Slag deposition on the downstream walls and its reaction with construction materials will be difficult to prevent. Separation of slag from alkali metals (seed) and other additives is an essential and formidable task. To minimize the particulate burden on MHD channel and air preheater (for direct-fired unit) the slag must be separated and discharged first. Therefore, the studies of the solubilities of K_2O, K_2CO_3 and K_2SO_4 with the electrode materials over the range of temperatures is of vital importance. Development of materials for deslagging zone needs careful attention. Alkali sulfates will limit the temperature to which alloy heat exchangers can be used.

In the area of MHD-related materials research, clearly long life operation of MHD channels and the corrosion-erosion by potassium seeds on both up and down stream equipments should receive the priority. The potential improvements in system performance with the changes in the seed reprocessing approach should also be investigated. The development and testing of electrode-insulator materials for hot-wall application, various refractories under MHD seed-slag conditions from 2100-3200^{o}F, and metallic materials at high temperature with high potassium levels for various downstream components need further research and investigation.

CONCLUSION

An improved understanding of corrosion chemistry in complex environments is needed for the effective use of metals and alloys in coal gasification/combustion systems. High temperature corrosion together with erosion of various components due to particulates, alkali metals and chlorine in the coal must be investigated and understood thoroughly before the final selection of materials. Successful economic development of all coal conversion and utilization processes will depend on the knowledge of materials behavior and subsequent development of new materials and/or improvement of existing available materials. The materials of construction for these applications in new base load power plants are considered to be available with some modifications. However, some basic research and development efforts are required or desirable to optimize our present materials knowledge in most areas.

From operating standpoint, reliability, availability and flexibility play more important roles than the efficiency of any particular process. Also from economic standpoint they are more important than the one time capital cost of materials. Clearly, there are major uncertainties in estimating cost and performance for system components that have never been built and tested, or for which only small scale experiment results exist. However, it can be assumed that there are no unsolvable materials development barriers despite the lack of any real operating life data on critical components. The attractiveness of both PFBC and MHD Systems relative to other alternative systems will only be affected by basic economic facts.

Based on our current limited knowledge of open cycle coal-fired MHD-Steam system and PFBC, we feel that the COE of each should be comparable to any other advanced energy conversion systems. Both systems definitely have the potential of becoming major thrust in electric power generation in 1990's. Unfortunately the National program does not seem to identify the materials problem properly. The utilities will be the ultimate users of these technologies and in some of the development areas their operating experience can be extremely helpful when these advanced processes are designed. They can provide their inputs to help establish the design guidelines. With the operating experience, the utility companies can assist the execution of the National program of any and/or all advanced processes by making step-by-step evaluations of the components and system designs. The material selection in all advanced energy conversion systems is a balance or "trade-off" between metallurgical and economic considerations. The optimum choice for maximum productibility may not be optimum for material performance and plant life. An economic compromise is often necessary to balance against plant life and there is no better judge than the utilities themselves to identify that. This rate may eventually lead to a smooth integration of MHD and PFBC systems into the existing power generating system when the processes will be sufficiently mature.

Hence, in our judgement the utility companies' active participation in the National program are absolutely necessary to develop a realistic research and development program for all coal conversion and utilization processes.

LIQUID FUELS FROM COAL UTILIZING THE EXXON DONOR SOLVENT (EDS) PROCESS

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In recent years, private industry has been working closely with the United States Department of Energy to develop technology which will permit utilizing coal as an alternative to conventional crude oil. A number of approaches have been pursued within the industry. These include direct combustion of coal, conversion of coal to a gaseous fuel, conversion of coal to a synthesis gas which is then recombined to form liquid fuels and direct liquefaction of coal. The latter involves production of liquid fuels by reacting coal in the presence of hydrogen and a solvent at elevated temperature and pressure.

The Exxon Donor Solvent process is a direct coal liquefaction process which has recently been brought to a state of commercial readiness(1) for a broad range of coals following an extensive development program carried out by Exxon Research and Engineering Company and funded jointly by the United States Department of Energy and other private industry sponsors. This paper describes the Exxon Donor Solvent process and the programs which h[illegible] been carried out to establish a technical basis for app[illegible]ing EDS Technology on a commercial scale. Resea[illegible] leading to this process was begun in 1966 by Exxon. A continuous effort has been under way since that time(2).

EDS Process Development Is A Joint Government/Industry Undertaking

The EDS process has been developed by Exxon Research and Engineering Company in a program jointly funded by the United States Department of Energy and private industry. The project began in 1976 and will continue through 1985, although most of the effort will be completed by mid-1983. The total cost of the development program is about 341 M$. In addition to the United States Government, the EDS project sponsors include Exxon Company, U.S.A., the Electric Power Research Institute, Japan Coal Liquefaction Development Company (which is a consortium of twelve Japanese companies), Phillips Coal Company, Anaconda Minerals Company, Ruhrkohle AG, a Federal Republic of Germany coal producer, and ENI, the Italian National Oil Company.

Under the terms of a cooperative agreement,(3) technical work on the EDS project is carried out by Exxon Research and Engineering Company, and other affiliates of Exxon Corporation. In addition, Exxon Research and Engineering Company is responsible for managing the project and for licensing the technology. Technology rights are shared among the Sponsors, as will be the licensing royalties. Sponsors provide funding, guidance for schedule and priorities, technical guidance, and information for technical and economic studies.

Process Description

In the EDS process, (Figure 1) feed coal is mixed with a hydrocarbon solvent, heated and fed as a slurry to a liquefaction reactor. The coal/solvent slurry moves upward through the reactor together with gaseous hydrogen. The coal is liquefied at 800-840^{o}F and pressure in the range of 2000-2500 psi. by reaction with molecular hydrogen and hydrogen donated by the solvent. The reactor effluent is separated into products using conventional distillation facilities. The donor solvent, now depleted of a portion of its hydrogen, is fed to a solvent hydrogenation unit where it is rehydrogenated, then recycled to the slurry mixer.

The use of a separate reactor for hydrogenation of the recycled solvent is a distinctive feature of the EDS process.(4) This step utilizes conventional petroleum technology for hydrogenating the solvent.

Depending upon the type of coal and operating conditions, 50-70% of the coal feed is converted to gaseous and liquid hydrocarbons. A residue of undistillable tar, unreacted coal and ash remains. This residue can be burned to provide steam and process heat in a "hybrid boiler" that is being developed under the EDS project.

Figure 1

EXXON DONOR SOLVENT COAL LIQUEFACTION

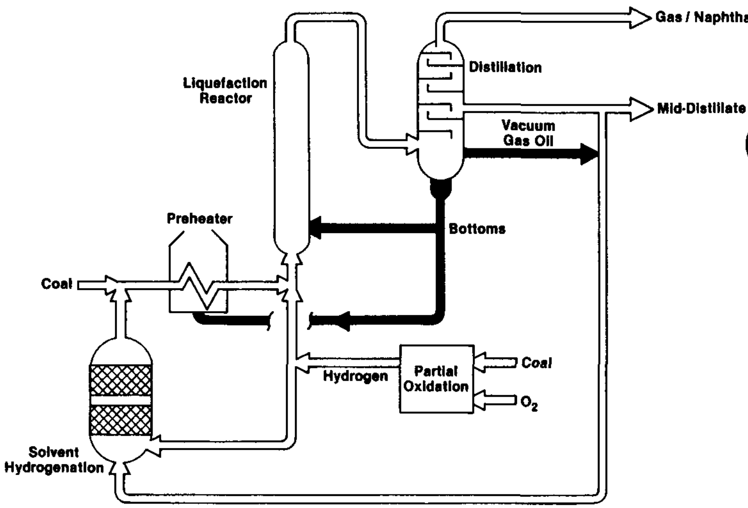
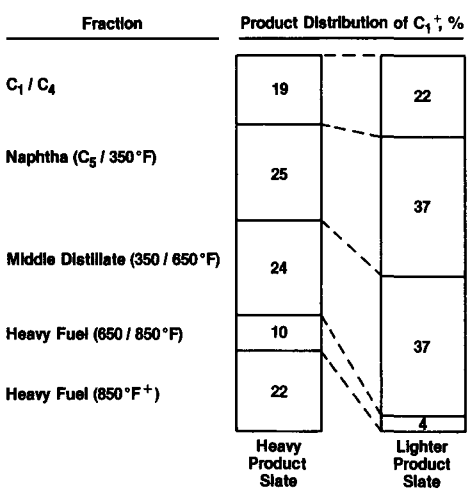


Figure 2

EDS PRODUCT DISTRIBUTION CAN BE VARIED TO MEET ALTERNATIVE LIQUID PRODUCT DEMAND



Additionally, we believe that existing technology for partial oxidation of coal can be adapted to convert the bottoms to synthesis gas which can be used as fuel, or upgraded to hydrogen.[5][6][7]

The amount of liquid hydrocarbons produced in the EDS process can be increased by recycling a portion of the bottoms to the liquefaction reactor. In addition, the heavy distillate stream can be recycled to make lighter products.

The EDS product slate can be varied to meet alternative demands as shown in Figure 2.[8] For example, the process can be run at conditions which produce a heavy liquid slate consisting of products boiling up to about 1000°F. These include a naphtha, middle distillate, gas oil and a heavy fuel oil fraction boiling in the range of 850-1000°F. Alternatively, a lighter product slate consisting of naphtha, middle distillate and only a small amount of gas oil boiling in the range of 650-850°F can be produced by increasing severity and recycling the heavy gas oil.

The EDS Project Has Involved a Wide Range of Development Activities

The EDS Project has included, within its scope, programs which address all critical issues which must be resolved to establish commercial readiness of this new liquefaction technology.

The liquefaction process has been developed to a state of commercial readiness for a broad range of coals and lignite.[9] This has involved obtaining data on process yields, operability and critical equipment design. Also, extensive studies have been carried out using a linear program model to determine economically preferred operating conditions and processes for hydrogen production and bottoms utilization.

A separate program is being carried out to develop a hybrid boiler to effectively utilize the bottoms residue. This material typically contains about 30% of the carbon fed to liquefaction and virtually all of the ash. The material is difficult to process because of its high viscosity and ash content. However, efficient bottoms utilization is a key to improving economics of direct coal liquefaction. The hybrid boiler permits utilizing the bottoms for generating steam and directly heating coal/solvent slurry to temperatures required for coal liquefaction. The hybrid boiler program involves EDS bottoms combustion testing[10][11] and engineering studies carried out by Exxon Research and Engineering Company and Combustion Engineering Inc. under subcontract to Exxon

Research and Engineering Company. The program is scheduled for completion by mid-1983.

Environmental issues have been addressed in programs which have focused on control of plant emissions, waste treatment, occupational health and toxicity of coal liquefaction products.(12)

Extensive studies have been carried out within the EDS project to evaluate the properties of EDS products, potential end uses and upgrading requirements.(13) EDS product combustion and upgrading has also been studied in programs outside of the EDS project.

The EDS Project has been based upon an integrated approach to process development (Figure 3). Bench scale experiments and small pilot plants ranging from 75 LB/D to 1 T/D have been utilized to establish a broad process data base and study response to process variables. The data from these units were used to set the basis for the 250 T/D EDS Coal Liquefaction Pilot Plant (ECLP) which was built to obtain equipment operability and scaleup data.

The smaller pilot plant and research and engineering activities continued in parallel with the large pilot plant program. These ongoing activities permitted development of bottoms recycle, an important process improvement, and its introduction into the ECLP program. Also, the ongoing research and engineering activities were instrumental in helping to resolve process problems encountered early in the ECLP program and in establishing correlations between ECLP and smaller pilot plant data. This will permit the future use of smaller pilot plants to obtain data on specific coals of interest without the need for further ECLP-scale testing.

Process Demonstrated in 250 T/D Pilot Plant on Feeds Containing Up to 23% Ash

The 250 T/D EDS Coal Liquefaction Pilot Plant (ECLP) located in Baytown, Texas, was the cornerstone of the EDS process development effort. The pilot plant was designed to gather data for equipment scaleup and assess process operability with commercial scale equipment.(14)

During the ECLP program, the capability of the EDS process to handle a broad range of coals was demonstrated. Tests were run successfully on Illinois bituminous coal, Wyoming sub-bituminous coal and Texas lignite. The latter feedstock contained up to 23 wt% ash, providing ECLP with its greatest challenge. These feeds have properties covering a range of feeds which represent a substantial energy supply. A summary of the coals tested under the EDS Project is shown in Table 1.

Figure 3

PROCESS DEVELOPMENT PROGRAM INTEGRATES RESEARCH, ENGINEERING AND PILOT PLANT ACTIVITIES

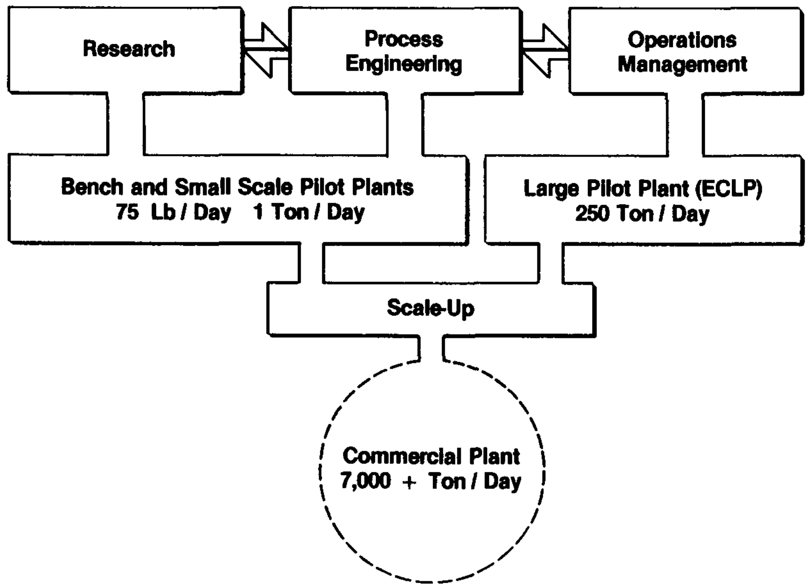


Table 1

Coal/Pilot Plant	75 LB/D	1 T/D	250 T/D
Bituminous			
Illinois #6 Monterey	X	X	X
Illinois #6 Burning Star	X	X	
W. Virginia Pittsburgh #8	X	X	
Sub-Bituminous			
Wyoming Wyodak	X	X	X
Australian Wandoan	X	X	
Lignite			
Texas	X	X	X
North Dakota	X		

ECLP was commissioned in June, 1980 on Illinois coal operating in a once-through mode, that is without bottoms recycle. The target service factor of 50% was obtained during the shakedown period which was followed by an inspection and turnaround. This was followed by operations on Illinois coal in the once-through mode during which the coal-in factor increased to about 72%. Following this run, facilities for demonstrating the recycle of bottoms were installed, and all subsequent operations were carried out in the preferred bottoms recycle mode.

Extended operations were achieved on Illinois coal, Wyoming coal and Texas Lignite in the bottoms recycle mode and an average coal-in percentage of 87% was achieved. In addition to the high coal-in factors, continuous coal-in periods in the range of 925 to almost 1400 hours were achieved for each of the bottoms recycle operations. Overall, ECLP logged over 10,600 hours on coal and processed about 90,000 tons of coal during the two year program. In addition to the large pilot plant operation, about 45,000 hours of coal-in operations have been accumulated in 75 LB/D pilot plants and about 17,000 hours in the 1 T/D pilot plant.

The large pilot plant demonstrated the operability and the flexibility of the EDS process both during normal operations and in response to upsets caused by factors outside the direct control of plant operators. The plant responded well to upsets such as loss of the hydrogen recycle compressor, large fluctuations in coal feed and purity of hydrogen supplied from outside the plant, and loss of power.

Design Criteria Established For Critical Equipment

An extensive testing program involving over 200 individual tests was carried out at the large pilot plant to obtain the data needed for design of the critical coal liquefaction plant equipment and hardware. The results of this program have contributed to advancing not only the EDS process but coal liquefaction technology in general.

Coal drying was demonstrated in both a gas swept mill and a slurry drier. In the gas swept mill, coal is dried using hot flue gases. Slurry drying utilizes hot recycle solvent to vaporize the coal moisture. This scheme, which is an innovation developed under the EDS Project that had not been previously demonstrated, results in simplified design and eliminates potential oxidation of coal which can cause significant loss of yield for some coals.

During the first year of ECLP operations, rapid coke buildup was experienced in the slurry preheat furnace. This prevented achieving desired operating conditions and yields. The problem was overcome by modifying the furnace design and plant operating procedures. These changes will be directly applicable to the design and operation of commercial-scale facilities.

Pumps, valves and instruments are among the most critical equipment for the coal liquefaction plant. Significant advances were made in development of this equipment. Particularly noteworthy, were the advances made in design and operation of reciprocating pumps in high temperature slurry service. These pumps were subject to heavy leakage of slurry from the plunger packing which initially had a life of only about 2 days before replacement. By the end of the ECLP program, packing life was increased to about 4 months through improvements in design and maintenance procedures. Important improvements were also made in the design of the high pressure slurry letdown valve which is used to reduce the pressure of a high temperature, solids-laden stream by about 2,000 psi.

One of the most important considerations in design and operation of ECLP was to confirm mechanical design and operability of the reactor system. The reactor system performed well and the data needed to support commercial-size facilities were obtained. This included data on the design and operation of the reactor inlet distributor which is required to assure uniform flow of the three phase coal/solvent/hydrogen mixture through the reactor and the system for withdrawal of solids which can build up in the reactors. Slurry distribution and solids withdrawal were issues which could only be resolved in ECLP size equipment.

In the area of fractionation, some problems were encountered early in ECLP operation with corrosion and erosion of internal components. These problems were readily solved by minor design and materials modifications. Finally, a substantial amount of data were obtained from the large pilot plant which will permit us to control air, water and noise emissions in commercial size facilities.

Correlations Provide Basis for Yield Scaleup

The 75 LB/D RCLU pilot plant has been the primary source of yield data in the past and will be used in the future to obtain data on coals not tested in ECLP. Sin ECLP was sized to permit direct scaleup of results commercial-scale, it was important to establish a co relation between RCLU and ECLP.

Extensive testing was carried out to define the hydrodynamics of ECLP and RCLU reactors and develop a model for scaleup of the smaller pilot plant data. Figure 4 shows the results of these modeling studies for Illinois coal. The model used to successfully predict ECLP conversion based upon the large RCLU data base can now be used to predict commercial-scale yields for coals not tested at ECLP.

Upgraded Liquid Products From EDS Process Compatible With Existing Markets

The EDS project has included a program to evaluate the uses for EDS products[12]. Data from this program confirmed the expectation that EDS naphtha is an excellent reformer feed and can readily be upgraded to high octane gasoline blendstock. Distillate is suitable for use as heating oil blendstock and stationary gas turbine fuel and with hydrotreating, as an automotive diesel fuel and jet fuel. If desired, the heavier gas oil fraction can be utilized as a fuel oil blendstock. Alternatively, the material can be recycled to the unit or it can be cracked external to the EDS process to produce additional distillate and gasoline.

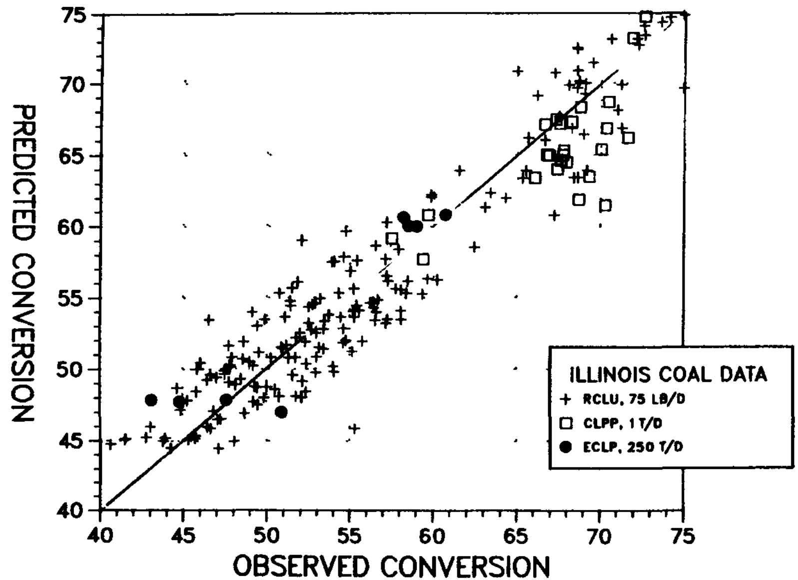
Data Available to Permit Environmentally Acceptable Plant Design

An environmental program has been carried out to obtain the data needed to manage plant emissions and minimize occupational health and product related ha ards[11]. Air, water, solids and noise emissions from t ECLP plant have been quantified and the data are availabl for future use in design of commercial-scale EDS plants. Engineering studies of alternative control schemes have been carried out and results indicate that a commercial-scale EDS plant can be designed to meet current EPA standards utilizing available control technology.

Studies are also in progress to identify any toxic hazards inherent in the EDS process and assess the magni-

FIGURE 4

CORRELATION BETWEEN ECLP AND SMALLER PILOT PLANTS
PROVIDES BASIS FOR SCALEUP TO COMMERCIAL SIZE



tude of risk associated with such hazards. Results of acute testing indicate that potential hazards in-plant are controllable by appropriate design features and sound industrial hygiene practices. In addition, product hazards are controllable by extinction recycle or hydrotreating of material boiling above about 700°F.

In the area of occupational health, over 2,000 employee years of experience with advanced procedures for personnel protection and monitoring have been logged at ECLP and in smaller pilot plant R&D activities.[16] This experience, along with data from over 2,000 personnel and area samples generted at ECLP are available for use in design of commercial-size EDS facilities.

Summary

The major elements of the EDS process development program have been completed and the data are now available to permit design of EDS liquefaction facilities to produce liquid fuel products from a broad range of coals and lignite on a commercial scale. Smaller pilot plants and scaleup tools are available to extend the large pilot plant learnings on three coals to most coals with potential commercial interest. The EDS technology is now available for licensing by Exxon Research and Engineering Company in behalf of the EDS Project Sponsors.

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REVIEW OF INTEGRATED TWO-STAGE LIQUEFACTION (ITSL) PROCESS WITH EASTERN BITUMINOUS COALS

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The Integrated Two-Stage Liquefaction (ITSL) process is receiving considerable attention as the most promising development in direct coal liquefaction. This process effectively converts coal to an all-distillate product slate, in contrast with earlier developments, which included production of boiler fuel. The developmental work of the ITSL process is being performed jointly by CE-Lummus, a subsidiary of Combustion Engineering Co., and Cities Service Research and Development Company, with support from other contractors.

In producing liquid products from coal, it is important for a process to provide the following features:

- Maximum distillate yield,
- Efficient hydrogen management,
- High thermal efficiency,
- Low hydrocarbon gas yields,
- Low heteroatom content in distillate products to minimize upgrading requirements.

The single stage liquefaction processes in advanced stages of development do not meet these goals, because of the high severity reaction conditions that are required. The processes are not selective, generally producing high gaseous yield, with high hydrogen consumption and low distillate quality.

In a two stage liquefaction process, coal liquefaction and upgrading reactions are separated. In so doing, the process becomes much more flexible with fewer constraints, and does not require high severity operation. The conditions for both liquefaction and upgrading reactions are selectively tailored to yield desirable products. With these inherent advantages, the two-stage liquefaction flow scheme is more suited for producing distillate products.

The first of the two stage processes to reach the process development (PDU) stage is the ITSL process developed at Lummus' facility in New Brunswick, New Jersey. This process integrates Short Contact Time (SCT) hydroliquefaction and LC-Fining (SM) hydrotreatment of the extract. The liquid and solid separation is achieved using the Lummus Antisolvent Deashing Process (ASDA). Except for the rejected ash-rich underflow from ASDA, the ITSL product consists of virtually all hydrotreated distillates and a small quantity of gases.

Under the funding of the Department of Energy, the ITSL PDU at Lummus' New Brunswick pilot plant has been operating since May, 1980 at a nominal capacity of 1/4 ton/day. Table 1 shows the history of the operation. Both Indiana V and Illinois No. 6 bituminous coals have been tested with success. Future developments will expand ITSL application to sub-bituminous coal and cleaned bituminous coal. The results reported in this paper cover extended runs on Indiana V and Illinois No. 6 coals.

Process Description

The process comprises three major process units:

a. First stage coal hydroliquefaction in the Short Contact Time (SCT) mode of operation.

b. Second stage upgrading, using CE-Lummus/Cities Service expanded bed catalytic LC-Fining process.

c. Deashing of the coal-derived liquid by the CE-Lummus proprietary Antisolvent Deashing Process (ASDA).

Table 2 summarizes the state of development of these units.

In the ITSL process, the deasher can be placed before or after the second stage LC-Finer, as shown in Fgures 1 and 2, respectively.

(SM) LC-Fining is a service mark of The Lummus Company for engineering, marketing and technical services related to hydrocracking and hydrodesulfurization processes for reduced crude and residual oils.

TABLE 1
HISTORY OF THE ITSL DEVELOPMENTS

1. Indiana V coal - First Stage Deashing, May 1980 to September 1981

2. Illinois No. 6 coal - First Stage Deashing, October 1981 to June 1982

3. Illinois No. 6 coal - Second Stage Deashing, July 1982 to present

TABLE 2
STATE OF DEVELOPMENT OF ITSL COMPONENTS

1. First stage SCT - Under development

2. Second stage LC-Fining (SM) - Commercially in use for processing of reduced crudes

3. Antisolvent Deashing (ASDA) - Design for 600 ton/day capacity (Catlettsburgh H-Coal Pilot Plant)

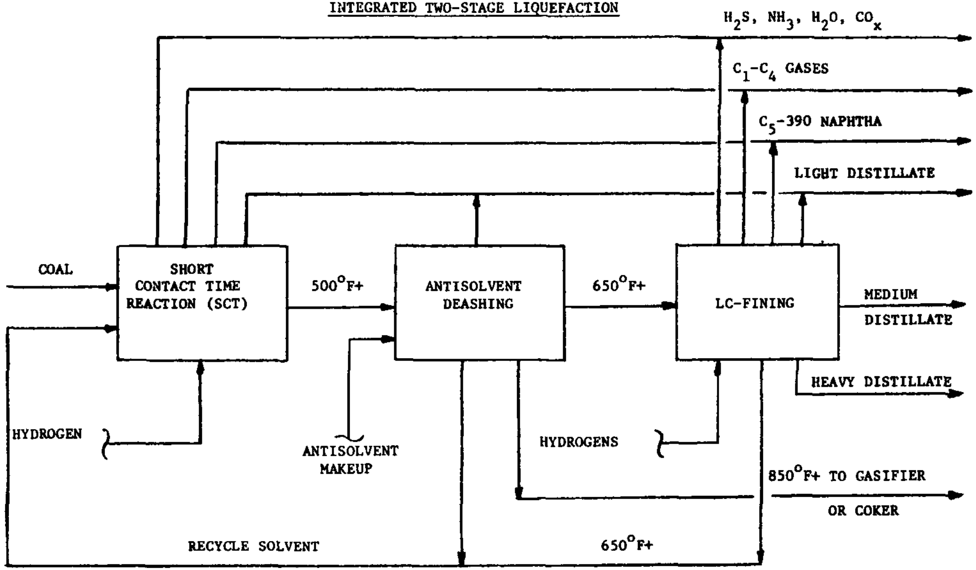
TABLE 3
COAL ANALYSES

	Indiana V Wt. %	Illinois No. 6 Burning Star Wt. %
Proximate Analysis		
Moisture Content	2.63	3.50
Volatile Matter (Dry Basis)	39.65	42.79
Ash Content (Dry Basis)	10.65	10.23
Fixed Carbon (Dry Basis)	49.70	46.98
Ultimate Analysis (MF Basis)		
Carbon Content	69.76	69.66
Hydrogen Content	4.80	4.66
Sulfur Content	3.41	2.94
Nitrogen Content	1.38	1.42
Oxygen Content (By Diff.)	10.00	11.09
Ash Content	10.65	10.23

FIGURE 1

BLOCK FLOW DIAGRAM (FIRST STAGE DEASHING)

INTEGRATED TWO-STAGE LIQUEFACTION



A. First Stage SCT

Dried and pulverized coal is mixed with the process-derived recycle solvent to a nominal 36 wt.% coal concentration. The coal slurry is mixed with make-up and recycle hydrogen and pumped to the SCT fired heater/reactor. The coal is first dissolved and is then thermally cracked. Over 90% of the MAF coal is extracted in this stage. The main product of this reaction is a non-distillable 850°F+ extract. A small quantity of gas and a small net yield of 500°F- distillates are also produced. The SCT product then goes through a flashing step where gases and light oil (500°F-) are drawn off the process. The 500°F+ material is then further processed in the downstream stages, either to the deashing stage (Figure 1) or to the hydrotreating stage (Fig. 2). Thus, the net ITSL product coming off the SCT stage is only the 500°F- material, constituting a small fraction of the coal feed.

B. Second Stage LC-Fining

Te SCT product, either deashed (Figure 1) or undeashed (Figure 2), is fed to the LC-Finer with make-up and recycle hydrogen. The feed composition can be adjusted by flashing off the lighter distillate. In this reactor, the feed is hydrogenated and a portion of the non-distillable 850°F+ extract is converted to lighter distillates in an expanded bed of hydrotreating catalyst.

The LC-Fining product is processed by a flash unit to draw off the distillate as the ITSL product. The unconverted 850°F+ and a portion of the 650°F+ distillate product are recycled, constituting a major portion of the SCT solvent. The balance of the solvent is made up by the SCT distillate bypassing the LC-Finer. Thus, the LC-Fining stage produces most of the ITSL distillate product. In addition, it replenishes hydrogen to the hydrogen-depleted solvent from the SCT stage.

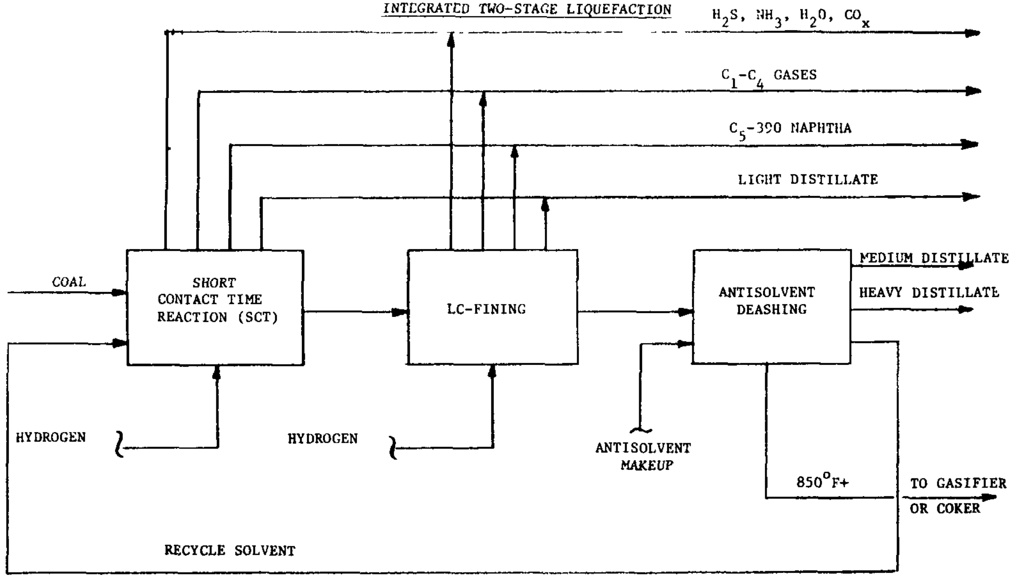
C. Antisolvent Deashing Unit

The 500°F+ material, either from SCT product (Figure 1) or from LC-Fining product (Figure 2) stream, is fed to the Anti-solvent Deashing Unit to remove the ash and unconverted coal. This is accomplished with the aid of a circulating antisolvent stream which promotes the agglomeration of the solid particles present in the slurry and permits their subsequent separation by gravity settling to the deasher underflow stream. The solid-rich underflow stream is vacuum flashed to retain distillate and the solid material is further concentrated in the vacuum flasher bottoms. This bottom material contains about 40-50% 850°F+ extract and in a commercial plant may be pumped to a gasifier to generate make-up hydrogen for the process. Alternatively, if hydrogen can be supplied by other sources, the solid rich stream may be pumped to a coker to recover additional liquid. It is estimated that up to 40% of the non-distillable material may be recovered by this means.

FIGURE 2

BLOCK FLOW DIAGRAM (SECOND STAGE DEASHING)

INTEGRATED TWO-STAGE LIQUEFACTION



The essentially solid-free overflow from the settling step goes first to an atmospheric flash, where the bottom stream is then fed to the downstream stage, either to the LC-Finer (Figure 1) or to the SCT solvent pool (Figure 2). The overflow atmospheric flash overhead and the underflow flash overhead go to a continuous distillation overhead and the bottoms contribute part of the recycle to SCT.

From this flow scheme, it can be seen that the only extract 50°F+) leaving the process is in the solid-rich stream to the gasifier. Thus, the goal of maximizing distillate yield from coal is realized.

Results

Table 3 shows the proximate and ultimate analyses of Indiana V and Illinois 6 coals. Both are bituminous coals with similar elemental compositions.

First Stage SCT

In the ITSL process, the SCT operational objective is to achieve maximum coal conversion to the quinoline soluble material. Since the reactions are thermal and non-selective, this unit has been run at mild severties to reduce yields of gases and low quality distillates, and to prevent possible repolymerization reactions. Table 4 summarizes the reaction conditions. The temperature profiles in the SCT coil are shown in Figure 3.

The SCT reactor was kept at an outlet temperature of 860°F and an outlet pressure of 2400 psig with Indiana V coal. After solvent equilibration with Illinois No. 6 coal, the outlet temperature was reduced to 830°F and the outlet pressure to 2000 psig. The coal concentration in the SCT feed was kept at a nominal 36 weight % and the solvent had a nominal initial boiling point of 500°F. SCT yields for the two coals are shown in Table 5. It can be seen that the gases and 500°F- distillate yields, the net ITSL product from the SCT stage, constitute only a small fraction of the coal. This is significant because the distillates coming out of the SCT are of lower quality compared with the products from the LC-Finer.

The consumption of gaseous hydrogen in the SCT stage is very y, generally below 0.5% MF coal, while the solvent provides over e weight percent hydrogen based on the weight of moisture-free coal feed. Microautoclave tests, performed by Conoco Coal Development Company, have also shown that the ITSL solvent is capable of converting greater than 90% coal in the absence of hydrogen[1].

TABLE 4
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
SCT OPERATING CONDITIONS

	Run SCT 21	Run 2 SCT 10
Feed Coal	Indiana V	Illinois No. 6
Coal Space Rate, lb/hr-ft^3	177	166
Coal Concentration, wt. %	36	36
Reactor Outlet Temperature, °F	864	831
Reactor Pressure, psig	2,450	2,000
Gas Rate, SCF/ton MF Coal	15,000	16,000
Recycle Solvent Composition, wt. %		
IBP-500°F	1.7	1.6
500-600°F	14.0	18.2
650-850°F	41.4	50.4
860°F+	42.9	29.9
% Preasphaltenes	10.3	6.4
% Asphaltenes	15.0	9.6

TABLE 5
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
SCT NET YIELD STRUCTURE

	Runs 21-6, 7, 8 Indiana V	Runs 2-10-1, 1A, 2 Illinois No. 6
	Net Yields lb/100 lb, MAF Coal	
Components		
H_2S, NH_3, H_2O, CO_x	6.4	6.4
C_1-C_4 Gases	2.4	0.6
C_5-500°F Distillate	3.7	1.6
500-850°F Distillate	10.9	0.5
Solids Free 850°F+	68.7	83.3
Unconverted Coal	8.1	8.0
	100.2	100.3
Hydrogen from Recycle Solvent	1.7	1.4
Hydrogen from Gas	0.2	0.3

TABLE 6
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
CURRENT LC-FINING OPERATING CONDITIONS

Maximum reactor temperature, °F	780
Average reactor temperature, °F	750
System pressure, psig	2,700
Space rate, volume 850°F+/hr-volume catalyst	0.43

FIGURE 3
SCT REACTOR TEMPERATURE PROFILE

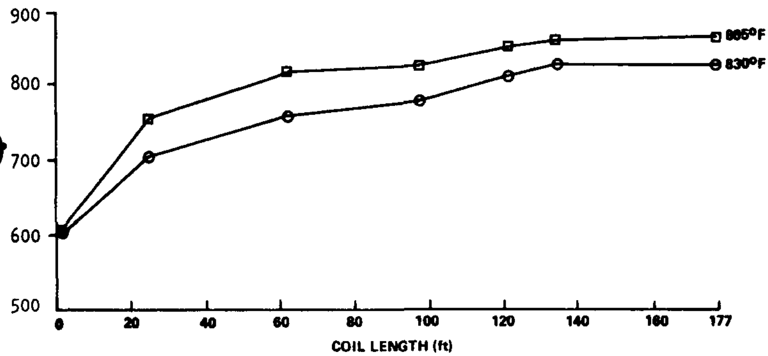
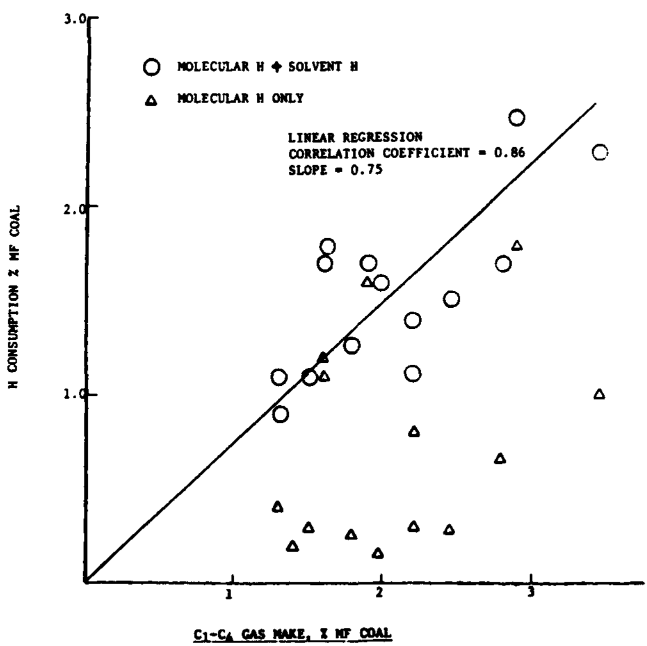


FIGURE 4

HYDROGEN CONSUMPTION VS C_1-C_4 GAS MAKE

SCT



The low consumption of the molecular hydrogen in SCT is an important development. It minimizes the hydrogen usage in the non-selective reactions, thereby increasing overall hydrogen efficiency. In addition, it may lead to reduction in SCT reaction pressure, resulting in a significant reduction in the compression cost. The effect of pressure on the SCT yields is being investigated.

The extent of hydrogen requirement in coal liquefaction may be related to the net-make of C_1-C_4 gases. Figure 4 shows that the hydrogen requirement in the SCT reaction was reduced in proportion to reduced C_1-C_4 gas yield at the lower reaction severity.

Second Stage LC-Fining

The LC-Finer stage converts the 850°F+ and the 650°F-850°F+ fractions to lighter distillates. In addition, it hydrogenates the hydrogen-lean solvent from the SCT stage. Reaction conditions are shown in Table 6.

The LC-Finer must convert the extract made in the SCT reaction minus the quantity that leaves in the vacuum-flashed, ash-rich stream. The temperature and space velocity are adjusted to achieve the desired conversion, but the 650°F+ product must also satisfy the solvent requirements of SCT.

Table 7 shows typical LC-Finer feeds for each coal. The products are listed in Table 8. The product distribution is somewhat heavier for the Illinois 6 extract. The C_1-C_4 make, however, is quite low for both coals due to the low reaction temperature and high catalyst selectivity used in the LC-Finer operation.

An objective of the ITSL process is to shift distillate production and hydrogen consumption to the LC-Finer where hydrogen utilization is more efficiently managed than in the thermal, higher-temperature first stage. Almost all of the hydrogen consumption of the ITSL process occurs in the LC-Finer. The hydrogen efficiency of the LC-Fining reaction is shown in Figure 5. Seventy-five percent of the chemical hydrogen consumption goes into making the C_4+ products; about ten percent goes to C_1-C_3 gases. The LC-Finer products are also of greater value because of their higher hydrogen content and lower heteroatom concentration. The improvement in product quality is illustrated in Table 9 which shows an increase of about one percent hydrogen in each fraction and 49-89 percent decrease in nitrogen and oxygen.

Antisolvent Deashing

Separation of ash from coal liquid has been performed on both the SCT product and the LC-Finer product. Typical feed compositions from these two streams are given in Table 11.

TABLE 7
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
LC-FINING FEED PROPERTIES

	Run 7-73 Indiana V Wt. %	Run 8-40 Illinois No. 6 Wt. %
Distillation Cuts		
IBP-650°F	3.8	4.0
650-850°F	40.9	39.4
Solids Free 850°F+	54.3	54.7
Solids (Q.I.)	1.0	1.9
	100.0	100.0
Percent Toluene Soluble in S.F. 850°F+	69.6	66.3

TABLE 8
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
LC-FINING

	Run 7-73 Indiana V Wt. %	Run 8-40 Illinois No. 6 Wt. %
Yields on Feed		
H_2S, NH_3, H_2O, CO_x	2.3	2.9
C_1-C_4 Gases	1.2	0.8
Naphtha	4.3	3.5
Mid-Distillate	27.4	16.1
Heavy Distillate	35.0	47.9
Solids Free 850°F+	31.3	29.8
Solids	1.0	1.9
	102.5	102.9
Wt. % S.F. 850°F Conversion	42.4	45.5

TABLE 9
INTEGRATED TWO STAGE LIQUEFACTION PROCESS

Comparison of typical SCT and LC-Fining distillate properties . . .

	% H	% N	% O
Naphtha			
SCT	12.2	0.23	3.8
LCF	13.3	0.06	0.7
500-650°F Distillate			
SCT	9.5	0.26	2.7
LCF	10.5	0.15	0.3
650-850°F Distillate			
SCT	7.7	0.40	1.4
LCF	8.3	0.21	0.5

FIGURE 5

LC-FINING HYDROGEN UTILIZATION

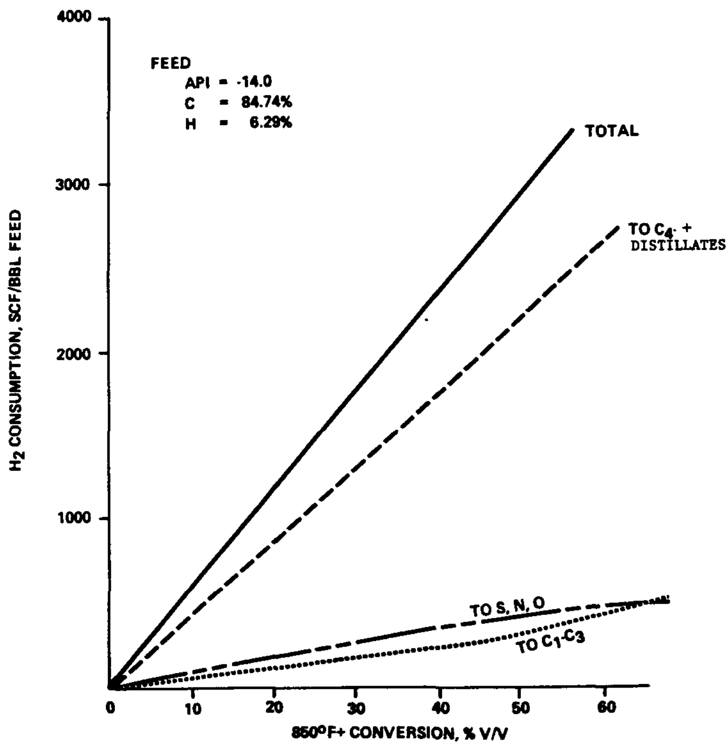


TABLE 10
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
ANTISOLVENT DEASHING FEED PROPERTIES

Run	149	159
Feed Source	SCT	LC-Finer
IBP-500°F	1.96	4.70
500-650°F	8.78	13.77
650-850°F	37.65	41.00
850°F+	51.61	40.53
Toluene Insoluble	23.28	13.30
Quinolene Insoluble	7.36	6.59
Ash	3.51	3.75

TABLE 11
INTEGRATED TWO STAGE LIQUEFACTION PROCESS
PREASPHALTENE AND QI BALANCE ON THE ASDA STAGE

BASIS: BALANCED 650°F+ AND ASH, FEED: 100 lbs.

	Toluene Insoluble		Quinolene Insoluble		QI/ASH		
Run	In	Out	In	Out	Feed	U'Flow	O'Flow
146	22.08	22.20	8.12	7.64	2.10	1.64	2.09
147	20.87	23.93	8.20	7.50	1.71	1.80, 1.69	-
148	24.90	25.00	7.20	5.70	1.60	1.66	-
149	16.0 17.6	17.20	5.07	5.25	2.10	2.09	-
153	23.17	22.87	8.52	7.52	2.22	1.89	-

No formation of quinoline insolubles or toluene insolubles in the ASDA operation.

TABLE 12
ITSL PROCESS
YIELD DISTRIBUTION

BASIS: 100 lbs MAF Indiana Coal

		NET CONTRIBUTION FROM	
	SCT	LC-FINING	TOTAL
H_2	(0.4)	(4.3)	(4.7)
C_1-C_4	2.4	2.7	5.1
C_5-390°F	0.2	7.2	7.4
390-500°F	3.5	7.0	10.5
500-650°F	0.2	28.1	28.3
650-850°F	0.0	9.0	9.0

Both these feedstocks were deashed with extract recovery of greater than 80% by the Lummus Antisolvent Deashing (ASDA) process, as shown in Table 10. The solid concentrations in the 850°F+ fraction of the underflow are in the range of 40% to 50%. The underflow is pumpable to either a gasifier or a coker.

The preasphaltene content of the extract in the deasher underflow is higher than that in the overflow stream. Analysis performed by Conoco Co. indicates that only the heaviest fraction of the preasphaltene, insoluble in the THF, but soluble in pyridine is preferentially fractionated. The ability of the deasher to reject this material may prevent its accumulation in the ITSL process.

Material balance calculations on the deasher unit shown in Table 13 indicates that the ASDA operation does not generate retrograde material, insoluble in toluene or quinoline. Thus, this deashing operation does not reduce liquid yields, or impair the upgradability of the coal liquid.

Integrated Two Stage Balance

Table 13 shows the integrated material balance for the ITSL process with four modes of operation. The yield structure in Case I is with Indiana V coal operation, while the other three cases are made with Illinois No. 6 coal. Except with Case III, where a 650°F- distillate yield is made, the other Cases are for 850°F- products. First-stage deashing (Figure 1) is employed in Cases I to III, while second-stage deashing (Figure 2) is used in Case IV.

In Table 13, no distillate product from the ash-rich 850°F+ stream in the deasher underflow is assumed. Additional distillate recovery may be obtained by coking this stream.

The solid concentration in the deasher underflow of Cases I to III is 48%, but it is 52% in Case IV due to the improved fluidity of this stream after hydrotreatment.

The yield of C_1-C_4 hydrocarbon gases is below 5% in all cases. The Indiana V coal has slightly higher gas yield due to the higher SCT temperature (865°F) operation. The C_5-850°F distillate yields are in the range of 49.3 to 53.5 wt.% of M.F. coal, or 3.0 to 3.2 bb. per ton of moisture-free (MF) coal.

The hydrogen consumption is between 4.2 to 4.7% MF coal. Higher hydrogen consumption in Case III is due to production of lower boiling distillate. The hydrogen efficiency, defined as pounds of distillate product per pound of hydrogen consumed is about 12.0. This value is reduced when producing lower boiling distillate (10.9 for Case III).

TABLE 13
ITSL NET YIELDS

Case	I	II	III	IV
Feed Coal	Indiana V	Illinois 6	Illinois 6	Illinois 6
Operational Mode	Figure 1	Figure 1	Figure 1	Figure 2
Distillate Boiling Range	C_5-850°F	C_5-850°F	C_5-650°F	C_5-850°F
Yields wt.% MF Coal				
Heteroatoms	13.26	13.56	13.64	13.54
C_1-C_4	4.54	2.62	3.56	3.73
C_5-390°F	6.65	7.35	11.28	6.21
390-500°F	9.37	9.73	13.56	10.29
500-650°F	25.26	19.04	26.41	15.50
650-850°F	8.01	15.54	-	21.43
850°F+ Solid Free	19.28	18.94	18.86	16.15
IOM	7.15	7.18	7.27	7.27
Ash	10.65	10.23	10.23	10.23
Total	104.17	104.32	104.72	104.35
Distillate Yields, BBL/ton MF Coal	2.96	3.07	3.18	3.16
H_2 Efficiency lb distillate/ lb H_2	11.8	11.96	10.90	12.28
H_2 Consumption SCF/Bbl Distil- late Product	5,058	5,052	5,329	4,942

TABLE 14
INTEGRATED TWO-STAGE LIQUEFACTION PLANT
DISTILLATE PRODUCT PROPERTIES - INDIANA V COAL FEED

Product	°API	Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur
C_5-390°F Naphtha	42.3	85.78	13.32	0.78	0.06	0.06
Light Distillate	22.4	87.20	10.82	1.66	0.13	0.19
Medium Distillate	13.4	89.04	10.46	0.31	0.15	0.03
Heavy Distillate	1.5	90.92	8.33	0.45	0.21	0.09
Total Distillate	17.1	88.56	10.57	0.65	0.14	0.08

Table 12 shows the distribution of the ITSL yields and the relative distributions from each stage. The major portion of the distillate product is produced in LC-Fining. Hence, the distillates contain low nitrogen (below 0.2%) and sulfur (below 0.1%) as shown in Table 14.

These results demonstrate that the ITSL process is capable of producing high quality distillate product with efficient hydrogen management.

Tables 15 and 16 compare the yield and product quality respectively, of the ITSL process with H-Coal and SCR-II processes. The ITSL process achieves a higher distillate yield of lower heteroatom content.

Conclusions:

Thirty months of PDU work with bituminous coals has demonstrated that ITSL is capable of achieving both greater yields of distillate product and higher product quality than any other direct coal liquefaction process. Illinois No. 6 (Burning Star Mine) and Indiana V (Old Ben Mine) exhibited only minor differences in the reactivity and overall yield structure.

By separating the hydroliquefaction and upgrading reaction stages, each reaction stage can be optimized in the ITSL operation. The recycle solvent contributes to the SCT reaction by donating hydrogen that is replenished in the LC-Fining stage. Hydroliquefaction of coal by this efficient transfer of hydrogen enables the SCT reaction to be run at relatively mild conditions, minimizing external hydrogen consumption and the yield of undesirable thermal product. By shifting virtually all of the distillate production to the lower-temperature, catalytic LC-Fining reaction, overall gas yields are minimized and distillate yields are maximized, resulting in a hydrogen utilization efficiency.

The solid materials in the coal liquid can be separated effectively using the Lummus Antisolvent Deashing process. This deashing operation can be performed either on the SCT product or on the LC-Fining product. It provides ITSL with great process flexibility in obtaining targeted product slates.

TABLE 15

INTEGRATED TWO STAGE PROCESS VS. SINGLE STAGE COAL LIQUEFACTION PROCESSES FOR ALL DISTILLATE PRODUCTS

	SRC-II*	H-Coal***	ITSL
Yields, wt. % of MAF Coal			
C_1-C_4 Gases	18.8	14.8	5.1
C_5-390°F Naphtha	11.6**	18.6	7.4
390-650°F Mid Distillate	20.3**	24.7	38.8
650-850°F Heavy Distillate	9.0**	5.3	9.0
Hydrogen Added, wt. % of MAF Coal	5.0	5.5	4.67
Distillate Yield, wt. % of MAF Coal	40.9	48.6	55.2
Hydrogen Consumption Efficiency (lb Distillate/lb Hydrogen Added)	8.2	8.8	11.8

* "The SRC II Demonstration Project," Freel, Jackson, Schmid; Synfuels Conference, San Francisco, California; October 1980.

** SRC II distillate boiling ranges are C_5-380°F, 380-600°F, 600-900°F

*** "Engineering Evaluation of Conceptual Coal Conversion Plant Using the H-Coal Liquefaction Process," EPRI AF-1297, Project 411-4; December 1979

TABLE 16

INTEGRATED TWO STAGE PROCESS VS. SINGLE STAGE COAL LIQUEFACTION PROCESSES - DISTILLATE PRODUCT QUALITY

	SRC-II*	H-Coal***	ITSL
Typical Distillate Nitrogen Concentration (wt. %)			
C_5-390°F Naphtha	0.45**	0.29	0.06
390-650°F Mid Distillate	0.80**	0.55	0.14
650-850°F Heavy Distillate	1.10**	0.73	0.21
Typical Distillate Sulfur Concentration (wt. %)			
C_5-390°F Naphtha	0.19**	0.06	0.06
390-650°F Mid Distillate	0.22**	0.08	0.07
650-850°F Heavy Distillate	0.38**	0.08	0.09

* "The SRC II Demonstration Project," Freel, Jackson, Schmid; Synfuels Conference, San Francisco, California; October 1980.

** SRC II distillate boiling ranges are C_5-380°F, 380-600°F, 600-900°F

*** "Engineering Evaluation of Conceptual Coal Conversion Plant Using the H-Coal Liquefaction Process," EPRI AF-1297, Project 411-4; December 1979

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AN OVERVIEW OF CATALYTIC CONVERSION OF COAL-DERIVED SYNTHESIS GAS

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INTRODUCTION

The United States has vast coal reserves that are, for the most part, presently being used as a heating fuel or for production of steam for generation of electricity. Coal gasification and catalytic conversion technologies provide another approach to utilizing the domestic coal reserves to produce a wide variety of useful products. This paper will examine several processes, with emphasis on United States projects, that are planned or in use for converting coal to coal liquids, chemicals, ammonia, and subsitute natural gas. All of these processes employ catalysts as the critical step in the conversion of gasifier product gas to the desired end product.

Conversion of coal to synthesis gas, mixtures of carbon monoxide (CO) and hydrogen (H_2), dates back to 1670 when John Clayton heated coal in a laboratory retort. Coal gas companies flourished in the United States during the nineteenth century and into the beginning of the twentieth century as small, local industries supplying medium-Btu town gas for heating and lighting. Inexpensive natural gas and oil and their distribution systems constructed during the 1920s and 1930s drove coal gas out of the market by the 1940s.

Synthesis gas has been produced domestically from natural gas or petroleum products. Technology to gasify coal and convert the coal-derived synthesis gas to various products has been available for decades, but utilized to only a limited degree overseas for coal liquids and ammonia production. In recent years, escalation of prices of oil and gas and advancements in conversion technologies, principally catalytic conversion, has improved the relative economics of coal-based processes. Commercial or semi-commercial demonstrations of technologies to produce ammonia, substitute natural gas, coal liquids and chemicals are underway. In contrast to early 1900 plants, current facilities are much larger to employ economies of scale to reduce the product cost.

The processing steps required to produce end products from coal via gasification are generally the same for each gasification and conversion process. As shown in Figure 1, synthesis gas is produced by reacting coal with steam and oxygen at high temperatures and pressures in a large reactor vessel, a gasifier. The precise make-up of product synthesis gas varies among the numerous gasifier designs. Synthesis gas consists primarily of H_2, CO, carbon dioxide (CO_2), methane (CH_4) and steam. The H_2 and CO concentrations will be in the relative proportions of less than one to almost three volumes of H_2 per volume of CO. Lesser constituents can include trace amounts of higher hydrocarbon compounds, ammonia and an assortment of sulfur-based compounds.

The first step downstream of the gasifier is to quench, or rapidly cool, the hot gas. The purpose of this step is not only to cool the gas, but also to remove coal-derived particulates and to lock in the most advantageous gas composition for subsequent processing steps. Following quench, a sulfur-resistant, water-gas shift catalyst (molybdenum-cobalt or nickel-molybdenum) is employed to adjust the H_2/CO ratio as required by the catalyst of the desired conversion technology. This is accomplished by reacting steam with the CO in the synthesis gas to form additional H_2 and by-product CO_2. An acid gas removal step is subsequently required to remove CO_2 and the sulfur compounds that are always present in coal-derived synthesis gas. The degree of sulfur removal is usually more dependent upon the tolerance of the conversion catalyst than on the specifications for the end product. Nickel-based methanation compounds, for example, are extremely sensitive to poisoning by sulfurous compounds and can tolerate only 0.1 part per million of sulfur - one-fortieth of the amount considered acceptable in pipeline quality gas.

The type of coal and gasifier, as well as the

Figure 1. Generalized Flowsheet for Production of Coal-Derived Products

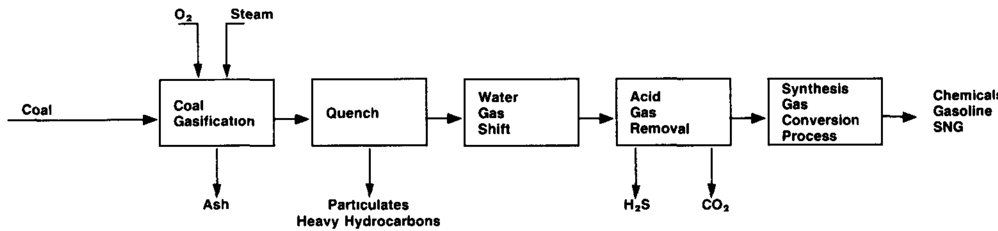
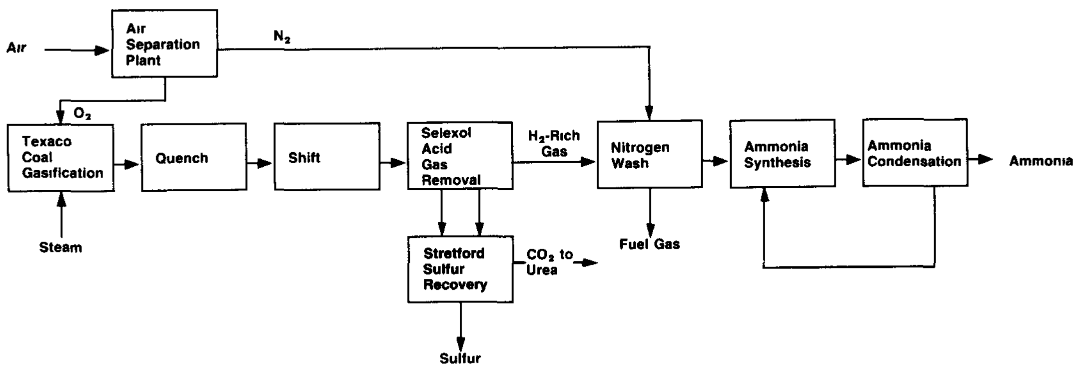


Figure 2. TVA Coal To Ammonia



$$3H_2 + N_2 \longrightarrow 2NH_3$$

required additional cleaning of the gas, are usually defined when the main end product of the process is established. The H_2/CO ratio of potential end products can range from zero (100% CO for carbonylation products) to infinity (100% H_2 for ammonia). Accordingly, the coals feedstocks and gasifiers are selected to produce gas closest in the H_2/CO ratio that is required for the eventual conversion to the end product to minimize t[illegible] processing steps required within the plant.

To review typical catalytic processes available for utilizing coal-derived synthesis gas, several commercially operating, near operational, demonstration and experimental coal conversion projects are considered. Brief descriptions of projects for the conversion of coal to chemicals, coal to liquid fuel and coal to gaseous fuels are included in the following sections. Since the catalyst are generally proprietary, detailed discussion of the compositions are not included in this paper.

COAL TO CHEMICALS

Tennessee Valley Authority Coal to Ammonia

The first modern demonstration of a coal to chemicals plant in the United States is the Tennessee Valley Authority (TVA) ammonia plant at Muscle Shoals, Alabama(1-3). This coal to ammonia plant, which began testing in 1981, consists of a coal gasification plant retrofitted to an existing ammonia plant at the National Fertilizer Development Center. In the TVA facility, the ammonia plant is rated at 225 tons/day, and the gasification plant is sized to produce 60% of the synthesis gas required, with the remaining being obtained from reformed natural gas. A primary objective of this demonstration facility is to provide information on the economics of substituting coal for natural gas as a feedstock for producing ammonia and subsequently fertilizer.

The simplified flow sheet for the TVA project is shown in Figure 2. The project uses a Texaco gasifier to convert eight tons/hour of Illinois #6 coal to synthesis gas. The entrained bed gasifier operates at about 5[illegible] psig and 2200°F. Oxygen and steam are used to gasify the coal injected into the gasifier as a coal-water slurry.

Raw gas flows through the quench scrubber to remove soot and water and then into two water-gas shift reactor vessels. These two reactors, operating in series, react CO and steam catalytically to produce H_2 and CO_2, reducing the CO concentration from 22% to 2% of the wet gas stream. To remove the sulfur compounds economically in the acid gas removal (AGR) process, the carbonyl sulfide (COS) formed in the gasifier must be converted to hydrogen sulfide (H_2S). A COS hydrolysis reactor, with an activated alumina or noble metal on alumina catalyst, is used to decrease the COS concentration from about 36 ppm to 7 ppm.

Following COS hydrolysis, the gas is treated to remove acid gases, sulfur compounds and CO_2 in a Selexol acid gas removal system. This selective, physical solvent system produces a clean, synthesis gas stream with less than 1 ppm total sulfur, a 4% H_2S/CO_2 stream, and a relatively pure CO_2 stream. Both sour gas streams are treated in separate Stretford units to recover elemental sulfur. The CO_2 stream is further purified by a zinc oxide guard prior to subsequent use for manufacturing urea.

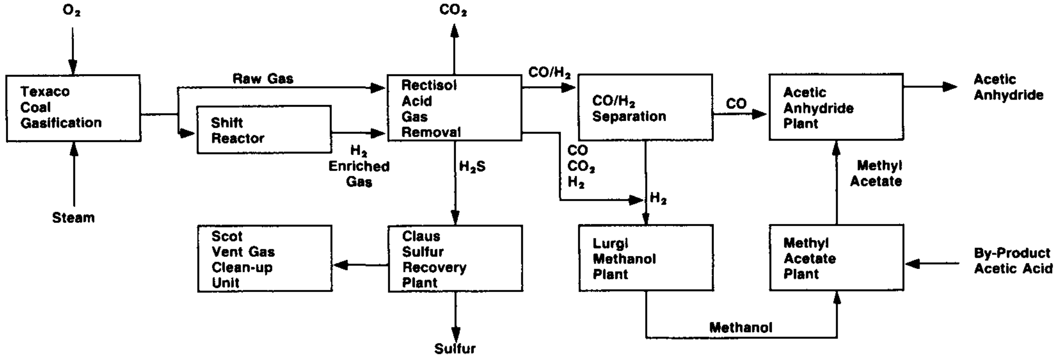
Synthesis gas from the AGR unit is mixed with nitrogen from the air separation plant to produce the required H_2/N_2 ratio of 3 and then further purified in a zinc oxide sulfur guard unit to lower the sulfur concentration to less than 0.1 ppm. The purified gas is then humidified to adjust the steam-to-dry gas ratio and heated to about 600°F. Humidified gas then enters the TVA ammonia plant upstream of the low-temperature shift converter at almost the same composition as natural gas-derived synthesis gas. The remaining ammonia synthesis steps include a liquid nitrogen wash to remove reaction inerts and ammonia catalyst poisons (such as methane, CO, CO_2 and H_2O), gas compression, catalytic conversion over an iron oxide catalyst, ammonia product condensation and recirculation.

<u>Eastman Kodak Coal to Acetic Anhydride</u>

Production of industrial chemicals from coal is the goal of the Eastman Kodak's project located at Kingsport, Tennessee (4-7); acetic anhydride and methanol will be the main products of the facility. The plant will be rated at 500 million pounds of acetic anhydride per year and is planned to be operational in 1983. The Kingsport location was selected because of Kodak's local acetic anhydride needs for producing photographic film base, cellulosic plastics, textile yarns and coating chemicals, and because of the availablity of a significant recycle stream of acetic acid from an adjacent Kodak plant.

The simplified flow diagram for the Tennessee Eastman project is shown in Figure 3. This project also uses a Texaco gasifier (described previously) to convert 900 tons/day of Appalachian coal to synthesis gas. Cooled gasifier product gas is split into two streams with one stream shifted catalytically to increase the hydrogen concentration so that the feedstream to the methanol

Figure 3. Tennessee Eastman Coal to Chemicals



Without Acetic Acid By-Product

$$4H_2 + 2CO \longrightarrow \underset{\text{Methanol}}{2CH_3OH}$$

$$\underset{\text{Methyl acetate}}{2CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}CH_3} + 2CO \longrightarrow \underset{\text{Acetic anhydride}}{2CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}\overset{O}{\overset{\|}{C}}\text{-}CH_3}$$

$$CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}\overset{O}{\overset{\|}{C}}\text{-}CH_3 + 2CH_3OH \longrightarrow 2CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}CH_3 + H_2O$$

$$4H_2 + 4CO \longrightarrow CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}\overset{O}{\overset{\|}{C}}\text{-}CH_3 + H_2O$$

Net reaction

With Acetic Acid By-Product

$$2H_2 + CO \longrightarrow \underset{\text{Methanol}}{CH_3OH}$$

$$\underset{\text{Acetic Acid}}{CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}OH} + CH_3OH \longrightarrow \underset{\text{Methyl acetate}}{CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}CH_3} + H_2O$$

$$CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}CH_3 + CO \longrightarrow \underset{\text{Acetic Anhydride}}{CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}\overset{O}{\overset{\|}{C}}\text{-}CH_3}$$

$$2H_2 + 2CO + CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}OH \longrightarrow CH_3\text{-}\overset{O}{\overset{\|}{C}}\text{-}O\text{-}\overset{O}{\overset{\|}{C}}\text{-}CH_3 + H_2O$$

Net reaction

synthesis will have a H_2/CO ratio of 2. The streams are sent to a Lotepro Rectisol unit for removal of CO_2 and H_2S and sulfur is recovered in a Claus unit in combination with a Shell Claus Off-Gas Treatment unit. Purified synthesis gas is then separated cryogenically by a Lotepro gas separation unit to produce a pure CO stream and a hydrogen-rich stream.

Following cryogenic separation, the hydrogen-rich gas from the shift unit and the hydrogen-rich stream from the gas separator are combined and fed to a low-pressure, high efficiency Lurgi methanol synthesis unit with a copper-zinc catalyst. Catalytic conversion of synthesis gas to methanol has been demonstrated overseas.(8) Methanol is reacted with acetic acid from a cellulose ester manufacturing operation to form methyl acetate. This esterification step can also be achieved by reacting methanol with recycled acetic anhydride if acetic acid is not available. Methyl acetate is then reacted with the carbon monoxide stream from the gas separator over a proprietary catalyst to form acetic anhydride.

COAL TO GASOLINE

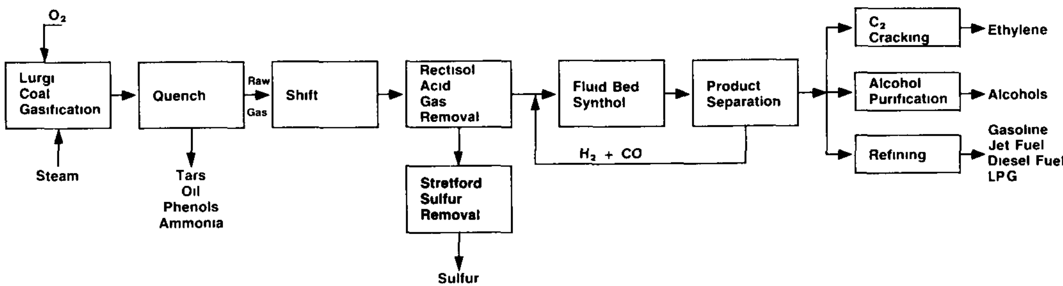
SASOL Coal to Gasoline

The world's largest coal conversion operation is the South African Coal, Oil and Gas Corporation complex in South Africa.(9-11) This complex consists of three plants: SASOL I in operation since the 1950's; SASOL II in operation since 1981; and SASOL III scheduled for completion in 1983. All of these facilities use Fischer-Tropsch chemistry to convert coal to liquid products indirectly via gasification. Direct liquefaction of coal in which the coal is converted to hydrocarbon liquids without being converted to gas first is under development, but is not currently practiced commercially. Products produced at SASOL include gasoline, diesel and jet fuel, olefins, oxygenated chemicals and waxes.

The simplified flow diagram for SASOL II is shown in Figure 4. This plant uses 30 dry bottom Lurgi gasifiers to convert 40,000 metric tons of Bosjesspruit coal per day to synthesis gas. These fixed bed gasifiers operate at about 450 psig and 1200-1500°F in the gasification zone using oxygen and steam as reactants to produce the raw synthesis gas.

Raw product gas exits the gasifier and is quenched to remove particulates and condensables, including tars, oils and ammonia. These by-products are separated, the particulates combusted for steam production, and the others sold as products. The raw gas from the quench system is shifted to adjust the H_2/CO ratio as required

Figure 4. SASOL Coal to Gasoline



$$(2n + 1)\,H_2 + n\,CO \longrightarrow C_nH_{2n+2} + n\,H_2O$$

$$2n\,H_2 + n\,CO \longrightarrow C_nH_{2n} + n\,H_2O$$

for the Fischer-Tropsch reaction and then is treated for acid gas removal in a Lurgi Rectisol unit. Sulfur recovery is performed by a Stretford unit. The purified gas exiting the AGR unit contains about 85% H_2 + CO, 13% CH_4 and 2% N_2 and CO_2 from where it flows into the Synthol system, catalytic fluidized bed reactors in which the synthesis gas is converted to gaseous and liquid products over a proprietary iron-based catalyst.

The Fischer-Tropsch catalyst can produce a wide range of hydrocarbons from methane to waxes. Reaction conditions can be varied to provide some control over the product mix so that subsequent operations can maximize production of gasoline, diesel/jet fuel, chemicals or SNG.

Synthetic oils (C_5 and heavier hydrocarbons) are initially removed from the gas stream by cooling the Synthol reactant gas. A subsequent lower temperature separation unit separates the remaining Synthol products into three fractions: the light fraction contains hydrogen-rich and methane-rich gas streams; the middle fraction contains ethylene, ethane and alcohols; and the heavy fraction contains C_3 and C_4 hydrocarbons. The hydrogen-rich phase is recycled to the Synthol system, the methane-rich phase is reformed with steam and oxygen to produce synthesis gas that is also recycled, the C_2 stream is cracked to produce ethylene, and the alcohols are purified. The heavy cuts (C_3 and heavier) are refined using conventional petroleum refining operations to produce nominally 24,000 barrels/day of gasoline, 13,000 barrels/day of jet and diesel fuel, and 4,000 barrels/day of LPG.

The production of gasoline via the Fischer-Tropsch process as used at SASOL has several disadvantages. High concentrations of methane that are formed in the gasifiers are unreactive in the Synthol reactors. This methane, and any methane formed in the Synthol reactor, must be reformed to produce synthesis gas because there currently is no market for SNG at SASOL. Because the Fischer-Tropsch catalyst is not selective for gasoline, significant quantities of hydrocarbon chemicals (900 tons/day) are formed. Finally, the gasoline formed by Fischer-Tropsch has a low octane rating requiring the addition of high levels of lead.

<u>Mobil Coal to Gasoline</u>

Disadvantages of the Fischer-Tropsch synthesis are reportedly overcome by the utilization of shape-selective zeolite catalyst, ZSM-5, developed by Mobil.(12-13) The zeolite catalyst promotes the desired reactions by restricting ingress and exiting of only the appropriate reactants and products by the catalyst structure. The

Mobil Methanol to Gasoline (MTG) process is shown in Figure 5. For a 50,000 barrel per day gasoline plant, about 25,000 tons of coal are required. The use of a gasifier that produces a high CO raw gas is preferred to satisfy methanol requirements. After quench, the raw gas is shifted to adjust the H_2/CO ratio to about 2, and then the acid gases are removed. The synthesis gas is then converted catalytically to methanol.

Gasoline production by the Mobil MTG process invol conversion of methanol to gasoline in the conversion reactors. The reaction first produces dimethyl ether and water from methanol during dehydration, followed by reaction of dimethyl ether and methanol to form light, then heavier, olefins. With proper recycle and catalyst selection, the olefins rearrange to paraffins, cycloparaffins, and aromatics without generating hydrocarbons higher than C_{10}. The product stream is cooled and separated into water, gas and light hydrocarbons. After water is removed, the separated gases are recycled to the MTG catalyst bed feed stream. Liquid hydrocarbon products require only minor treatment by conventional oil refinery steps to produce low lead, high octane gasoline with liquid petroleum gas (LPG) as a by-product.

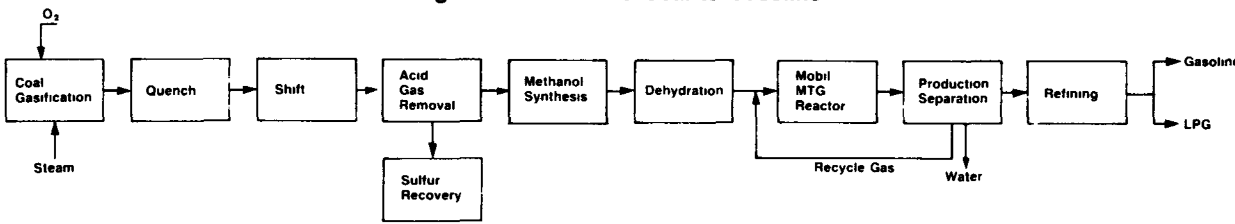
The Mobil MTG process has been chosen by New Zealand for a 14,000 barrel per day natural gas-to-gasoline project to be operational by 1985 and for the domestic W.R. Grace & Company coal-to-gasoline project.

COAL TO SUBSTITUTE NATURAL GAS

Great Plains Gasification Associates

The Great Plains Gasification Associates (GPGA) facility for the production of substitute natural gas (SNG) is under construction in Beulah, North Dakota, and is scheduled for operation in 1984.(14) A simplified flow diagram of the GPGA facility is shown in Figure 7. This facility uses 12 Lurgi gasifiers to convert 14,000 tons of North Dakota lignite per day to synthesis gas. The gas treatment system is essentially the same as that described previously for the SASOL facility, i.e., g quench, water shift to a H_2/CO ratio slightly more t 3, Rectisol acid gas removal and Stretford sulfur r covery. Here, the conversion process consists of methanating the synthesis gas using a nickel catalyst. Purified synthesis gas is mixed with recycled product gas and then flows into adiabatic-packed catalyst beds where the carbon oxides and hydrogen react to form methane and water. A final polishing methanator is required to

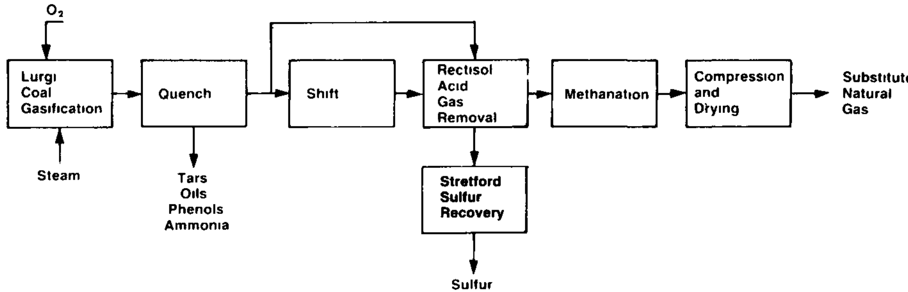
Figure 5. Mobil MTG Coal to Gasoline



$$4H_2 + 2CO \longrightarrow 2\ CH_3OH$$
Methanol

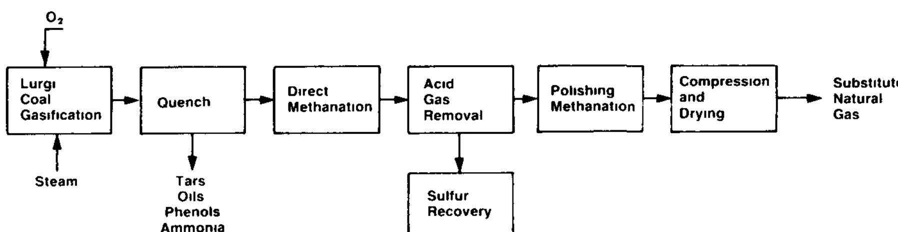
$$2\ CH_3OH \longrightarrow CH_3\text{-}O\text{-}CH_3 + H_2O$$
$\downarrow$
Light olefins, water
$\downarrow$
C_5 + Olefins
$\downarrow$
Paraffins, cycloparaffins, aromatics

Figure 6. Great Plains Coal to SNG



$$3H_2 + CO \longrightarrow CH_4 + H_2O$$

Figure 7. Direct Methanation Coal to SNG



$$2H_2 + 2CO \longrightarrow CH_4 + CO_2$$

satisfy the pipeline specification of a maximum of 0.1% CO in the final product, prior to dehydration and compressing to pipeline standards. The facility is rated at 137 million standard cubic feet of 977 Btu/ft^3 (HHV) SNG per day with a 91% plant on-stream factor.

Direct Methanation - Coal to SNG

The Gas Research Institute (GRI) is developing a new methanation process, called direct methanation to distinguish it from current technology, that differs from that described previously for SNG production. Although the process described in this paper is specific for use with dry bottom Lurgi gasifiers, the technology will be applicable to use with all coal gasifiers. The process is based on a catalyst developed by Catalysis Research Corporation under GRI contract that is sulfur resistant and able to convert equal molar concentrations of hydrogen and carbon monoxide to methane and carbon dioxide, in contrast to the production of methane and water for the current nickel-base catalyst. It also provides resistance to carbon formation at low steam concentrations and low H_2/CO ratios in the gas.

The simplified flow diagram for direct methanation in a Lurgi-base plant is shown in Figure 7. Raw gas would be quenched as presently planned by Great Plains for Lurgi gasifier raw gas, but would then be methanated without shift or sulfur removal. Acid gas removal after bulk methanation would treat a smaller gas volume because of the methanation reaction stoichiometry. At present, a trim methanator would be required to assure the gas meets pipeline standards for carbon monoxide.

A first-pass techno-economic assessment by C F Braun & Company under GRI contract showed a potential of a 5-7% decrease in the cost of gas for direct methanation over conventional technology for a 250 million standard cubic feet per day dry bottom Lurgi plant using Western subbituminous coals. While the current catalysts have been tested only at the laboratory scale, GRI plans to continue the development through the pilot scale to ready the technology for commercial application.

Conclusions

Expanded use of coal-derived chemicals, substitute natural gas and hydrocarbon liquids is projected in the domestic energy supply of the future. All of the current processes for coal conversion employ catalytic processes as the critical steps in the process. While some of these catalytic processes are not new, improved processes and catalysts are being developed. Recent developments in catalyst technology provide the promise of improved yields and lower production costs. These advancements arise from greater understanding of the mechanism of catalysis resulting, for example, in development of shaped catalysts in which the structure, as well as chemical composition, is a controlling parameter. Further research in catalysts and catalytic processes is needed to continue these advancements to maintain and improve the economic competitiveness of coal-derived products.

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OVERVIEW OF COAL GAS PURIFICATION TECHNOLOGY

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Raw gases from coal gasifiers in general are hot and dusty, present a surprisingly broad mixture of components, and may be at pressures ranging from nearly atmospheric to 1,000 psi or more. The capital cost for cleaning and purifying this gas frequently exceeds the corresponding cost of any other section of a coal gasification plant, amounting to 15-20+% of total plant cost. Preliminary conditioning usually amounts to cooling (quenching) and removal of condensables and particulates, so that the residual mixture of gases can be treated for removal of CO_2 and H_2S (the acid gases) by one of a number of possible established processes. All of the known processes are aimed at the selective removal of H_2S and CO_2 in the presence of a mixture of other "permanent" gases with minimal loss of the permanent constituents.

Most gas purification plants consist (see Figure 1) of an absorption tower (absorber) and regenerator (stripper). In the absorber the solvent flows counter currently to the ascending gas, absorbing the removable components physically or chemically. Suitable internals in the form of packing or trays promote mass and heat transfer. The rich (or "fat") solvent is withdrawn from the bottom of the absorber and sent to the regenerator where absorbed components are removed by thermal or chemical treatment. The lean solvent is returned to the top of the absorber for further duty.

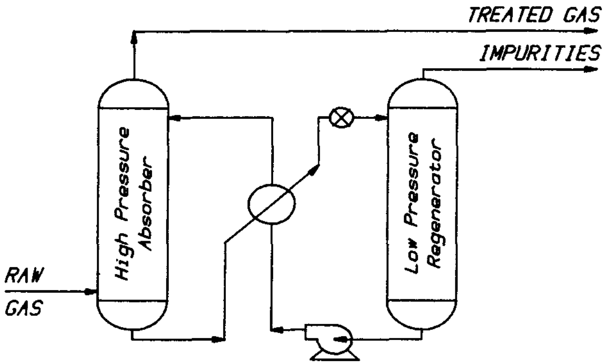


Figure 1

SIMPLE GAS PURIFICATION

Absorption generally occurs at low temperature and under elevated pressure while regeneration is accomplished at high temperature and low pressure. The temperature gradient is utilized by heat exchange between the cool fat solution and the hot regenerated solution, and the pressure gradient energy is recovered with expansion turbines. All absorption-regeneration processes operate continuously.

The majority of the known processes were developed to meet the needs for natural gas sweetening, for petroleum refining and for manufacture of hydrogen and ammonia. These gas streams typically are relatively "pure" when compared with the quenched raw gas from a coal gasifier, as they lack some of the numerous so-called "trace" components found in raw coal gas. Adaptation of these processes to purification of coal derived gas leads to economic penalties to overcome the disparity of feed gas composition. Such penalties are encountered in increased capital cost and increased operating expense. The gas compositions shown in Table 1 illustrate the large differences in coal gas composition between two different coal gasification processes and the large difference between both of these coal gases and one typical refinery sour gas stream. Clearly, purification of coal gas streams will require a most flexible and adaptable process to meet technical and economic requirements of the various coal gasification processes.

Coal gas differs markedly from the refinery gas of Table 1. For example: (1) the level of CO_2 in the refinery gas is roughly 70% of that for K-T and about 16% of that for Lurgi; (2) the H_2S level in the refinery gas is from 40 to 57 times that for the coal gases; (3) the acid gas ratio, CO_2:H_2S, in the coal gas ranges from about 55 to about 340 times that for the refinery gas; and (4) the coal gas streams contain a

TABLE 1
TYPICAL COMPOSITIONS, DRY GAS
TO ACID GAS REMOVAL, MOL % (10)

Component	Quenched Raw Gas Lurgi	K-T	Refinery Sour Gas
Hydrogen	37.6	32.74	-
Oxygen	0.6	-	-
Carbon Monoxide	16.7	57.35	-
Methane	9.1	-	8.4
Ethane	0.7	-	5.2
Propane			4.6
Isobutane			2.5
Normal Butane			7.5
Normal Pentane			3.4
Hexane			1.0
Naphthalene	0.7	-	-
Nitrogen + Argon	0.6	1.16	-
Ammonia	0.2	-	-
Hydrogen Cyanide	2.7	-	-
Carbonyl Sulfide	-	0.114	-
Hydrogen Sulfide	1.1	1.59	62.5
Carbon Dioxide	30.0	7.05	4.9
	100.0	100.00	100.00
CO_2/H_2S	27.3	4.43	0.08
Temp. ^oF	850	2700	122
Press, psia	300	15	22

large variety of contaminants not present in the refinery gas, some of them highly toxic. Additional "trace" substances can and do appear in some coal gasifier raw gases, examples of which are benzene, toluene, xylene, phenols, thiocyanates, and mercury. These trace contaminants in coal gas have the potential to generate serious gas purification problems through recycle build-up in the liquid absorbent used for gas absorption. Toxic contaminants, such as hydrogen cyanide, carbonyl sulfide, and mercury, are not tolerable in the product gas.

The importance of the ratio CO_2:H_2S is related to the recovery of sulfur from the acid gas after its removal from the main stream, usually by means of the Claus process which requires a feed containing at least 20% H_2S. Thus the CO_2:H_2S ratio should be less than 4:1 for acceptable sulfur recovery economics. If all the acid gas of the K-T process of Table 1 were absorbed completely and produced as feed to a Claus process, the feed would contain only about 18% H_2S; for the Lurgi process it would be only 3.5% H_2S. A desirable gas purification process would split the absorbed acid gas into a stream of high purity CO_2 for venting to the atmosphere and a stream of concentrated H_2S (at least 40%) in CO_2 for feed to a Claus sulfur recovery unit. In the case of refinery sour gas (Table 1) the acid gas feed to the Claus unit would contain nearly 93% H_2S.

AGR PROCESS TYPES

Processes for removal of CO_2 and H_2S are based on (a) *chemical reaction*, (b) physical absorption, (c) *condensation* and (d) combinations of these.

(a) Chemical Reaction

In general, the chemical reaction cases involve substantial thermochemical energies of absorption at elevated pressure, and the inverse energies are encountered during desorption at substantially lowered pressure. Absorption via chemical reaction has the disadvantage of low thermodynamic process reversibility. Other difficulties arise because of absorbent degredation and because of corrosion of vessels, pumps and piping. Examples of chemical AGR processes using thermal regeneration are found in the proprietary Hot Carbonate process, the Alkazid Wash, Adip Wash, Sulfinol Wash, and in the generally non-selective, low pressure amine based processes commonly found in the petroleum and natural gas industries. Some success has been achieved with selective absorption of H_2S and CO_2 employing membrane technology with potassium carbonate solution as the absorption medium.

(b) Physical Absorption

Physical absorption processes depend solely on pressure and temperature of the gas-liquid equilibrium, which, to a limited degree, is dependent upon the choice of liquid absorbent. Absorptive capacity in general can be increased by absorption at lower temperature and at higher pressure. Energies of absorption and desorption are normally much smaller than in chemical absorption, giving rise to greatly reduced thermal effects per mole of gas absorbed. For example, absorption of a lbmole of CO_2 in the hot carbonate process releases about 13,500 Btu, but physical absorption releases about 3,500 Btu, or one quarter of the thermal effect of chemical absorption. However, the enthalpy decrease of carbon dioxide which accompanies physical absorption is not small. It causes significant rise in temperature of the liquid absorbent, with a consequent lowering of equilibrium concentration caused by the rise of temperature. This effect frequently is so great that cooling of the absorbent liquid is required, normally by withdrawing the hot liquid to an external heat exchanger and returning the cooled liquid to the absorption tower on the next lower tray or packed section. An alternative of limited value is to increase the flow rate of liquid absorbent to provide a larger heat sink and thus a smaller temperature rise. Economics of increased tower size and internals versus external interstage cooling determines the choice between these alternatives.

Theoretically any liquid can be used for physical absorption of gaseous components. Practical commercial considerations limit severely the choices available on the basis of (a) availability, (b) cost, (c) solvent loss via vapor pressure, (d) solvent degredation with time, (e) corrosion of equipment, (f) specificity for absorption of a particular component, (g) molecular weight, (h) density, (i) viscosity and, to a lesser degree, (j) specific heat. Items g, h and i are principal determinants of absorption efficiency, usually referred to as tray efficiency or, for packed towers, HETP, height equivalent to a theoretical plate. Absorption efficiency is enhanced by an absorbent liquid of low molecular weight, high density and low viscosity. Since gases are physically absorbed on a molar basis, a liquid absorbent of low molecular weight promotes high gas solubility per unit mass of absorbent. Thus liquid circulation rates are reduced with consequent reduction of tower size and pumping requirements. These lead to reduced capital and operating costs.

Water has been employed for absorption of CO_2 and H_2S from pressured coal gasification gases, natural gas and refinery gas, but with limited success. Organic sulfur compounds, gum-formers and hydrogen cyanide are not removed completely. Relatively low gas solubility requires large water circulation rates, thereby entailing large power consumption costs. Much more successful physical absorption processes are the well known proprietary processes shown in Table 2. Rectisol is used commercially to purify coal derived gases. Selexol has been specified for two coal gasification pilot plants but has not yet operated in a commercial coal gasification process. Both processes have seen duty in petroleum refineries. Purisol and Fluor processes have not been applied to pilot plant or commercial coal gas purification.

Physical absorption processes have potential for selective absorption of one component over the one or more others to be removed. However, ability to remove a component completely (say to less than 1 ppm) depends heavily upon complete absence of the component in the regenerated solvent. Thorough regeneration of solvent is essential, since unremoved components exert their equilibrium effects in the absorber and tend to inhibit complete absorption. The myriad "trace" components found in raw coal gas virtually assures the presence of components difficult to remove in regeneration. Such components accumulate in the recycling solvent until reaching a concentration such that removal by regeneration is exactly in balance with accumulation by absorption. If the rate of removal by regeneration is less than the rate of feed to the absorber, absorption will be incomplete and the treated gas will be impure. Unsatisfactory gas purification can result from difficulty in absorption (poor solubility) or from difficulty in adequate

TABLE 2
FEATURES OF PHYSICAL ABSORPTION
ACID GAS REMOVAL PROCESSES

Process	Solvent	T/P	Selectivity H_2S/CO_2	Selectivity CO_2/HC	Solvent Loss	Util.
Rectisol	Methanol	Low/Hi	Good	Poor	Hi	Mod/Low
Selexol	DMEPG*	Mod/Hi	Good	Mod	Low	Low
Purisol	NMP**	Mod/Hi	Good	Mod	Low	Low
Fluor	Propylene Carbonate	Mod/Hi	Mod	Mod	Low	Low

*dimethyl ether of polyethylene glycol
**N-methyl-2-pyrrolidone

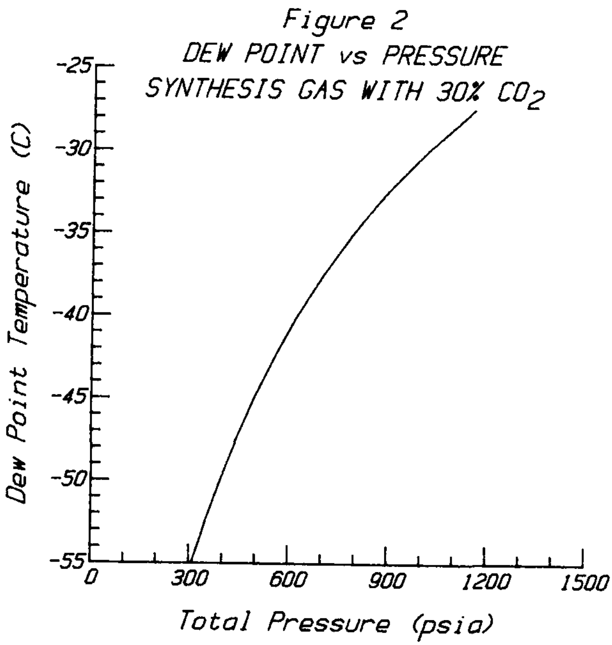
regeneration with respect to the offending component. If the offending component is toxic, corrosive, or tends to promote formation of gums, deposits and the like, achievement of complete removal is essential.

Physical absorption processes generally operate with substantial pressure differences between absorber and regenerator, accompanied by a thermal difference to aid in the stripping function of the regenerator. While conservation of energy is practiced via heat exchange and power recovery, it is done at the expense of capital equipment and the inevitable loss of thermodynamic efficiency.

Physical absorption processes would approach perfection with: (a) minimum pressure difference between absorber and regenerator; (b) minimum temperature difference between absorber and regenerator; (c) complete regeneration to produce solvent containing none of the feed gas components, and (d) a solvent with good specificity for desired components, low molecular weight, low viscosity, and very low vapor pressure.

(c) Condensation

When the component to be removed is present at adequate partial pressure, cooling of the gas to its dew point temperature causes condensation to begin. Figure 2 shows the dew point of a pressurized synthesis gas containing 30% CO_2. Continued gradual cooling causes condensation to occur in a close approach to thermodynamic reversibility, a process of maximum thermodynamic efficiency. Co-condensation of other components, according to their individual solubilities, occurs simultaneously. Further cooling yields further condensation, but extended cooling provides diminishing condensate per unit temperature drop, and is limited by the condensate freezing temperature. The temperature at which cooling is halted is an economic choice, related to specification for residual CO_2 in the treated gas and



technology available for further treatment, if necessary, to achieve treated gas specification. Condensation can remove bulk CO_2 (at adequate partial pressure) from a syngas at adequate total pressure, and in so doing contribute significantly to good process efficiency and improved process economics.

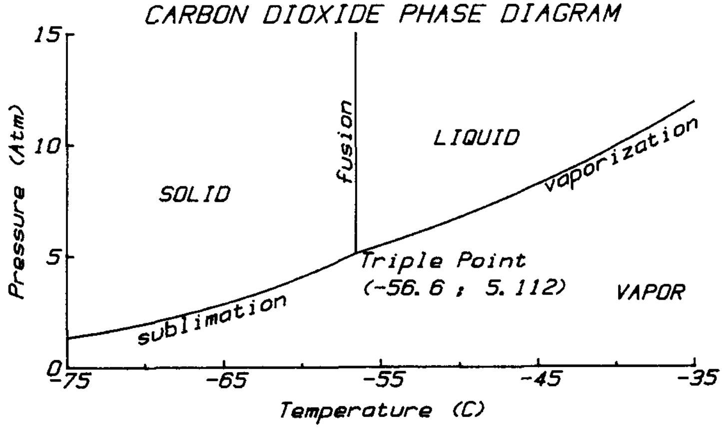
Bulk condensation of CO_2 leads to a departure from standard absorption-regeneration technology in that separation of the condensate components may be performed by distillation, with or without preliminary flash separations. Distillation to produce pure CO_2, however, is made difficult by the approach to equal volatility for CO_2 and H_2S at high CO_2 concentration and by the formation of a CO_2 ethane azeotrope (67% CO_2, 33% C_2H_6). Separation of methane from CO_2 by distillation, which appears easy, encounters severe solid CO_2 deposition at pressures below 715 psia. All schemes to avoid this problem have led to unacceptably high capital and energy cost when compared with available alternatives. An exception is found in the Ryan-Holmes process, in which addition of butane or natural gas liquids at the condenser prevents solid CO_2 formation in the demethanizer, prevents ethane-CO_2 azeotrope formation in the de-ethanizer, and enhances the separation of H_2S from CO_2 by distillation (13).

In the CNG Acid Gas Removal Process currently under development, distillation has been abandoned in favor of triple-point crystallization to produce virtually 100% pure CO_2 from a condensate containing H_2S and all other trace components thus far identified. Triple-point crystallization is an efficient, effective means to: (1) produce a pure liquid CO_2 for complete absorption of all trace components; (2) produce pure CO_2 as a product or for venting to the atmosphere; (3) completely remove all contaminants from the treated gas; (4) eliminate all trace contaminants from the recycle CO_2 used for absorption; (5) provide for rejection of contaminants with the small acid gas stream sent to sulfur recovery, and (6) produce an acid gas stream rich in H_2S for substantial improvement of sulfur recovery economics. High thermodynamic efficiency results from the nearly reversible process of triple-point crystallization, as only slight pressure changes cause melting or freezing without heat exchange surfaces.

(d) Combinations

Process types can be combined in ways that are advantageous for specific applications. When the concentration of acid gas is low, chemical removal or physical absorption alone is likely to be adequate. As the carbon dioxide concentration and total pressure of the raw gas are increased, the potential for simple condensation becomes attractive, as is evident in Figure 2. Cooling for condensation of CO_2 is limited to about -56.6°C at partial pressures of at least 5.112 atmospheres (75 psia) as indicated by the triple-point in the CO_2 phase diagram of Figure 3. Carbon dioxide remaining in the vapor phase at the above condition depends upon total pressure. Thus at 1,000 psia

Figure 3
CARBON DIOXIDE PHASE DIAGRAM



the gas contains (75/1,000)(100) = 7.5 per cent CO_2; at 300 psia the concentration is 25 per cent CO_2. These residual levels can be further reduced to 1.0 or even 0.1 percent CO_2 by absorption-regeneration processes such as Selexol, Rectisol, Hot Carbonate, etc. For gases of high CO_2 partial pressure, condensation offers improved economics and avoids forcing the absorption-regeneration system to function beyond its intended range of economic usefulness. Carbon dioxide condensation should be considered for CO_2 partial pressures exceeding 75 psia, and the process configuration decided on the basis of economics. Examples of combined process types are found in Ryan-Holmes (13) and in the Cryofac (9) processes for natural gas treating.

Summary

The foregoing discussion of acid gas removal technology has identified the principal characteristics that are desired, if not actually needed, in an AGR process applied to coal gasification. The process should:

(1) Produce high purity CO_2, preferably with sulfur content well below 1 ppm, as an item of commerce or for environmentally acceptable venting to the atmosphere.

(2) Produce an acid gas stream for sulfur recovery that is as rich as possible in hydrogen sulfide (40% to 75+%) for maximum favorable combined AGR-sulfur recovery economics.

(3) Remove completely all "trace" contaminants from the treated gas.

(4) Reject completely all removed "trace" contaminants into the small acid gas stream for sulfur recovery to minimize or eliminate recycle absorbent build-up. If special treatment is required for any specific one or more of these contaminants, treatment cost is minimized because the gas stream is small and contaminant concentrations are maximized.

(5) Regenerate the absorbent to a purity approaching 100% to favor complete removal of all contaminants from the main gas stream.

(6) Employ an absorbent of near-optimal properties at process conditions for maximum absorption efficiency and desirable economics: low molecular weight, low vapor pressure, high liquid density, low liquid viscosity, high specific heat, good chemical stability, non corrosive to equipment, readily available at reasonable cost.

(7) Achieve goals (1) through (6) within the constraints of acceptable capital and operating costs.

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ONSITE FUEL CELL PROGRAM - A STATUS REPORT

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Introduction

The gas industry, faced with increasing natural gas prices and declining markets, has an opportunity to explore a new business opportunity that can both benefit the gas utility and the gas ratepayer. The onsite fuel cell system, powered from natural gas, provides the industry with the type of hardware needed to offer its customers a full energy service. The onsite fuel cell power plant is an electrochemical device designed to continuously transform the chemical energy of a hydrogen-rich fuel, such as natural gas, into electricity and usable heat. This cogenerator seems to be most economically and technically attractive in commercial, multifamily residential, and light industrial buildings where the thermal requirements exist year-round and fuel cell modules in the 40kW to 400kW electrical output range can be utilized.

The gas industry Onsite Fuel Cell Program is aimed at producing the technical, economic, and institutional data necessary for the pioneering utilities and the leading fuel cell manufacturer to establish an initial business venture in the mid 1980s. GRI, together with the U. S. Department of Energy and over 25 participating gas and combination utilities are conducting a field test of the onsite fuel cell hardware, and developing the technology to the point of commercial readiness, so that the specific data needed by both the manufacturer and the utilities to define an acceptable business venture can be generated. It is intended that this present R&D program will culminate with the manufacturer and utilities continuing in a mutually agreed upon buy/sell relationship. It is the purpose of this paper to present the results to date of the efforts outlined above.

Background

An onsite fuel cell power plant is an electrochemical device designed to continuously transform the chemical energy of a hydrogen-rich fuel, such as natural gas, into electricity and usable heat. Onsite fuel cell power plants contain three major subsystems, or sections. In the fuel-processing section, natural gas is converted to a hydrogen-rich fuel. The fuel is then fed to the power section where the hydrogen is electrochemically reacted with oxygen from the air to produce direct current (DC) electricity and by-product heat in the form of hot water or steam. The DC electricity is converted in the power-conditioning section to alternating current (AC) at the frequency and voltage levels commonly distributed throughout the United States. See Figure 1.

Although the basic concept underlying the Onsite Fuel Cell Energy System dates back to the mid 1800s, an English scientist by the name of Francis T. Bacon pursued the development of the technology in the 1930s through 1950s. In the early 1960s, the U. S. National Aeronautics and Space Administration (NASA) adopted the fuel cell as the power source for the manned space missions. The gas industry has long been aware of the potential benefits in developing onsite fuel cell energy systems. In the late 1960s, an organization of gas utilities called the Team to Advance Research on Gas Energy Transformation (TARGET) initiated a program to develop a fuel cell power plant for residential and commercial use. This group of gas utilities, in cooperation with United Technologies Corporation (UTC), developed a 12.5kW power plant which demonstrated an electrical efficiency of [illegible]. In the early 1970s, a test of 65 of these power plants was conducted in the United States, Japan, and Canada. The test provided valuable information on commercial prospects and identified areas where additional technology and component developents were needed. During the following 12 years, the technology has progressed significantly. Under the joint sponsorship of the Gas Research Institute (GRI) and the U. S. Department of

FUEL CELL POWER PLANT FUNCTIONAL DIAGRAM

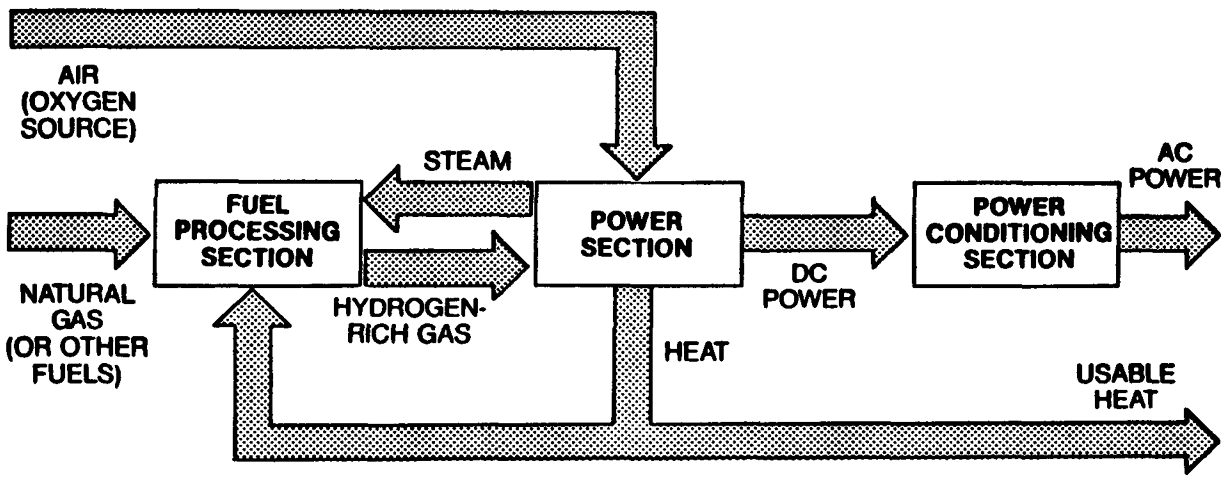

FIGURE 1

Energy (DOE), a scale-up in size to a larger 40kW power plant with the addition of heat recovery capability was designed and built, and the technical feasibility verified in over 7,000 hours of laboratory testing. That leads us to the present day, where GRI, DOE, and a group of over 25 gas and combination utilities have launched into a program aimed at both field testing the onsite fuel cell power system and completing the technology efforts required to bring onsite fuel cell components and designs to the point of commercial readiness. See Figure 2.

Energy Service Concept

The key to the gas industry's interest in the fuel cell over the years has been the concept of its use in an "Energy Service." Energy Service, in the sense used here, includes the onsite delivery and sale to a consumer of the form of energy which meets his particular facility needs. The onsite fuel cell is a cogeneration device which can provide both the electrical and thermal requirements of many multi-family residential, commercial, and light industrial buildings. Because of the unique characteristics of fuel cells over other more conventional small cogeneration systems, the fuel cell shows promise of being the technology which will make a broadly applied Energy Service practical. The onsite fuel cell offers high electrical conversion efficiency, high total fuel utilization when the reject heat is utilized, modular design, unattended operation, good reliability, low noise and pollution levels, grid quality power, and energy cost savings. The concept of an onsite fuel cell Energy Service business offered by the local gas utility could result in both lower total energy bills for the commercial gas ratepayer, while providing the gas industry a new business and market option.

Field Test Effort

The purpose of the field test effort is to obtain critical operational data and to technically evaluate fuel cell technology as a viable onsite Energy Service. During 1982, the first two GRI/DOE initial preliminary fuel cell field test power plants were installed, dedication ceremonies held, and over 2,800 hours of operation completed. These units are 40kW in size, are grid connected, and have heat recovery capability. One unit is located at a commercial laundry in Portland, Oregon in the service territory of Northwest Natural Gas Company. The unit provides the majority of electricity needed to operate the facility as well as the supplemental heat for two 1,200 gallon tanks of laundry water. During

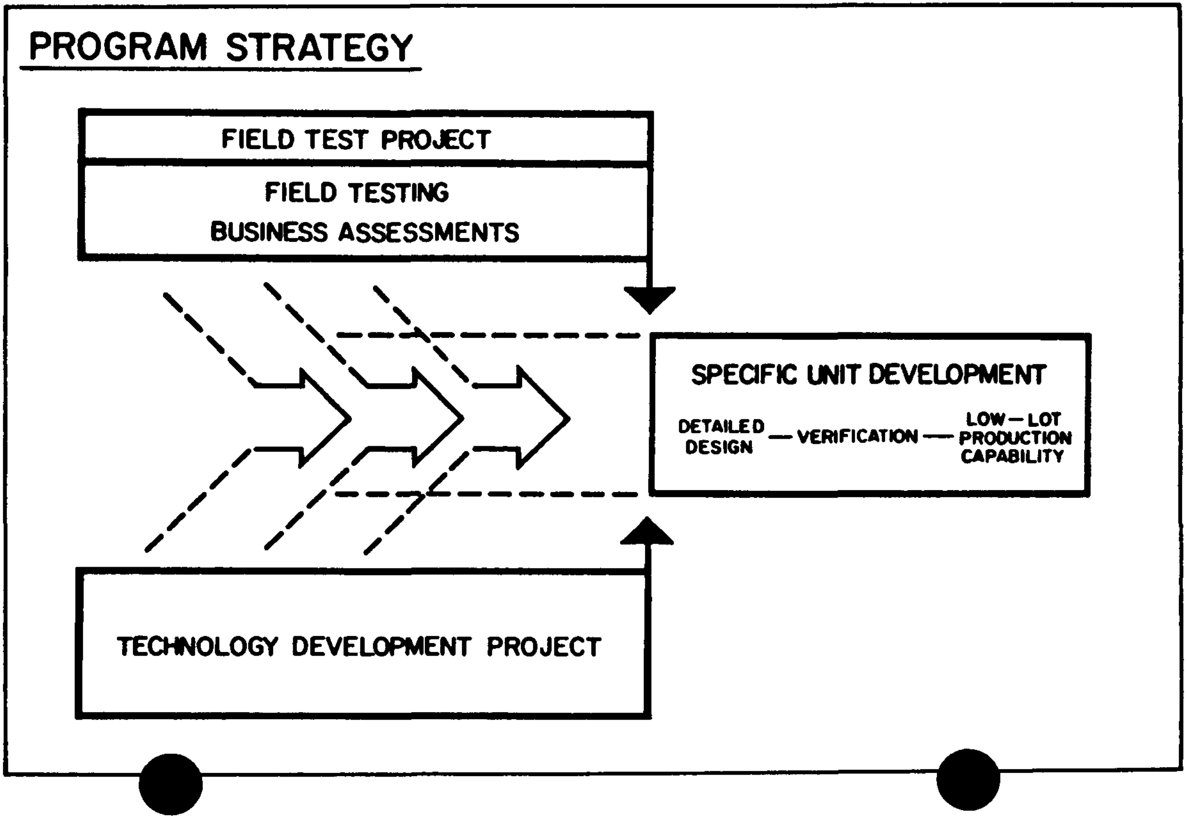
PROGRAM STRATEGY
FIELD TEST PROJECT
FIELD TESTING
BUSINESS ASSESSMENTS
SPECIFIC UNIT DEVELOPMENT
DETAILED DESIGN — VERIFICATION — LOW-LOT PRODUCTION CAPABILITY
TECHNOLOGY DEVELOPMENT PROJECT

FIGURE 2

normal working hours, the water tanks use all the heat supplied by the onsite fuel cell power plant, reducing the load on the main boilers by 14%. The fuel cell provides the laundry with essentially all of the electricity it requires. At night and on weekends, the heat energy from the fuel cell keeps the water tanks at 150°F. Electricity produced during these periods is sold back to the local electric utility at a price of 4.2¢kWh. The second unit is located at a Southern New England Telephone Company switching building in the Rockville, Connecticut service territory of Northeast Utilities. The onsite fuel cell is capable of providing all the space heating when the outside temperature is above 12°F. Below that point, some supplemental heat is needed. In addition, the electrical power produced by the fuel cell system will be used 24 hours a day to supply more than 50% of the electricity needed to provide telephone service to 20,000 customers. This installation became operational in October 1982.

In a parallel activity, three additional 40kW size fuel cells with heat recovery, built by UTC under private contracts, were installed and operated in 1982 - two in Japan and one in Mexico. The combined hours of operation for all five early units totalled over 4,800 hours, providing valuable power plant operating experience in preparation for the extensive GRI/DOE 45 unit field test scheduled to begin in the latter part of 1983 and continue through mid 1985. The 45 unit field test will verify onsite fuel cell operation in a variety of applications (including nursing homes, hospitals, apartment buildings, restaurants, and recreation facilities) in a variety of climatic conditions. See Figure 3. During the first 4,800 hours of operation the three major subsections of the fuel cell have performed well. No failures due to fundamental problems with the reformer, stack, or inverter have occured. Ease of power plant installation and start-up has been demonstrated with the Northwest Natural Gas Company unit taking less than 2 weeks to commence operation from the time the power plant arrived in Portland, Oregon. The two units installed in the United States have operated in a grid connect mode, testing the protective and interface capabilities of connecting the fuel cell to the electric utility grid. The two Japanese units have been operating in the grid isolated mode, testing the power plants ability to instantaneously respond to electric load variations.

However, as with any test, the initial experimental power plant installations have not been without problems. In June of 1982, a contamination problem of the

40-kW fuel cell field test
PARTICIPATING UTILITIES

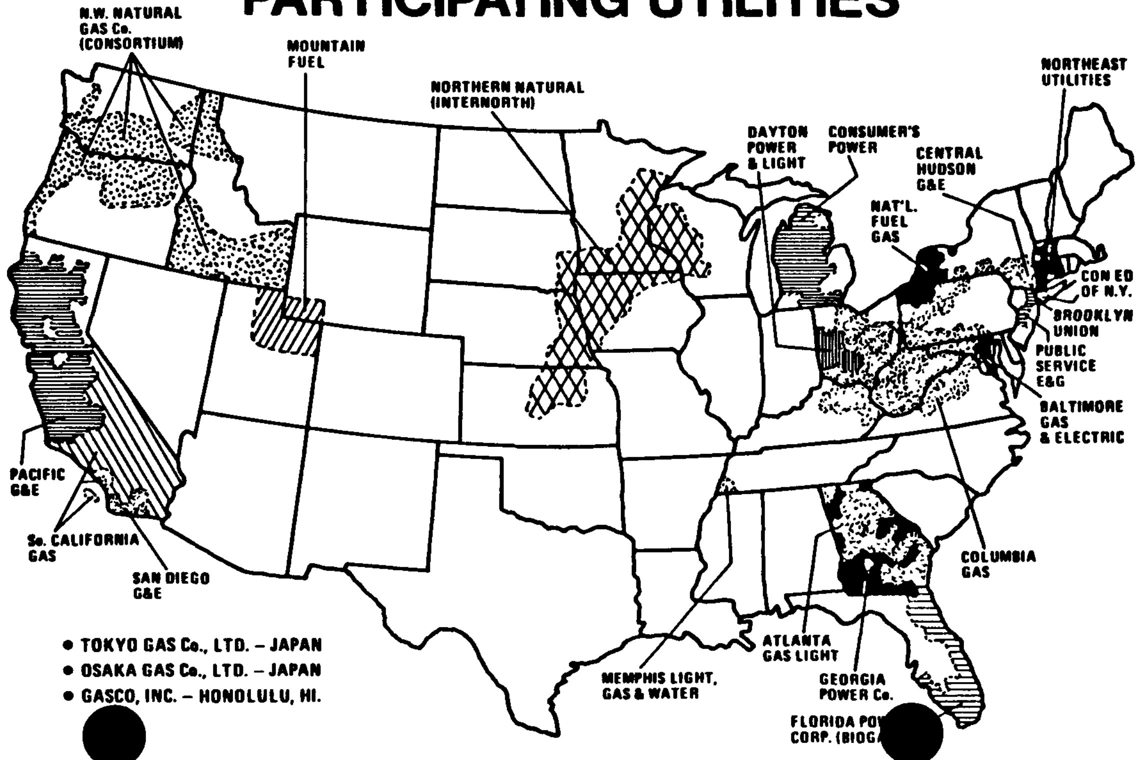

FIGURE 3

coolant loop was experienced in the Northwest utility unit. The problem was traced by UTC to inadequate coolant treatment, and testing resumed in early September to verify the corrective actions taken. In late November, the Northeast Utilities' unit shutdown automatically due to a thermal malfunction. An onsite investigation by UTC showed that a coolant system leak had developed. A more detailed analysis identified the cause of the failure as a substantial reduction in coolant flow because of cavitation of a recently installed retrofit coolant pump. This coolant flow reduction should have caused no problem other than a nuisance shutdown, since the coolant system includes a flow switch designed to shut the power plant down should the coolant flow drop below a preset value. However, it is believed that the cavitation of the coolant pump resulted in failure of this switch to operate. These two concurrent and related failures resulted in the power section operating over temperature and subsequent fracture of a coolant hose. At this point, other protective controls took over and the power plant shutdown without further incident. These coolant loop problems have been the most serious problems experienced to date. In addition to these, several nuisance problems have arisen such as defective printed circuit boards, several sticking solenoids and control switches, and restricted airflow in a particular heat exchanger (to mention a few). However, it must be remembered that the intent of the first two preliminary power plant installations is to identify those changes that must be made to assure a more trouble-free field test beginning in late 1983. Also, the 45 unit field test is aimed at identifying those problem areas that must be addressed prior to a manufacturer's commercial offering.

The manufacturing of the 45 units for field testing in late 1983 is on cost and on schedule. NASA is administering that contract for GRI and DOE. Delivery of the first units is scheduled for September 1983 with deliveries continuing through August of 1984. In preparation for the delivery and installation of these 40kW power plants, the 25 participating utilities are presently instrumenting and collecting electrical and thermal energy usage data in over 80 potential sites around the country. From these sites, 25 to 30 sites will be selected for the actual fuel cell installations. The selected sites will be a good cross section of building types and climatic conditions. The energy data collected at the 80 sites is being analyzed as to how a fuel cell might operate in the building with various fuel cell system installations, various modes of operation, and various energy costs. An hour by hour simulation of the fuel cell operation is conducted and compared to the presently existing or updated conventional system. The outputs of the program are such characteristics as the fuel cell thermal capacity factor, electric capacity factor, and percent of total fuel utilized. In addition, a breakeven or allowable installed cost for the fuel cell can be calculated. Figure 4 represents three specific sites where data was collected for one year. You can see the variation in the breakeven cost as a direct function of the fuel cell heat utilization or capacity factor.

In addition to the hardware tests and the site specific data collection, each participating utility, as part of the Field Test Project, is required to conduct a market and business assessment of onsite fuel cells. The key to the gas industry's interest in the fuel cell has been the concept of its use in an "Energy Service." The concept of providing and billing end-use energy forms such as hot and chilled water, steam, electricity, and refrigeration has been explored successfully chiefly in large central plants. The fuel cell could potentially open up a much broader market in commercial and light industrial applications and could ultimately evolve to residential service as well. Existing engine and turbine equipment has not broadly penetrated these markets, in great part due to their complexity, lower efficiency, noise and emissions concerns. There may be some cases where a utility may not wish to pursue the Energy Service. The fuel cell offers the opportunity to be examined as an Energy Service mechanism, a cogeneration system or an appliance. It is anticipated that as a result of the Field Test Project, which will be completed in mid 1985, the technical basis and experience will be gained for each of the participating utilities to make a sound decision on whether to commit to an onsite fuel cell Energy Service business in their service territory.

Technology Development Efforts

Both GRI and DOE are funding a coordinated multi-year project which will lead to the definition of a fuel cell power plant that can meet the cost requirements of an early entry market and still maintain the technical specifications required by the utilities. The activities can be divided into two major areas; system definition/costs and component/system development. Under the first area, extensive work is ongoing defining specifications for the initial commercial power plant. Input from the field test, market studies, and utility fuel cell groups are valuable in defining a piece of hardware that meets the user requirements. Cost trade-off studies are being conducted on system modifications and value engineering efforts are ongoing to better define manufacturing cost

REPRESENTATIVE ANALYSIS SUMMARY - FIELD TEST SITE DATA

Site Type	Site Date	Operating Mode	System Configuration	$/kWh Elec.Cost	$/MCF Gas Cost	$/kW Breakeven	% Fuel	Elec. Capacity	Thermal Capacity	Comments
Restaurant/Motel	1 yr.	Fixed Power	DHW/Storge	.078	5.24	2,465	80	100%	94%	200 gal. storage
Motor Inn	1 yr.	Fixed Power	DHW/Storage	.078	5.30	1,142	53	100%	33%	Resized conventional plus supplemental boilers
Nursing Home	1 yr.	Fixed Power	DHW	.08	5.28	1,893	58	100%	43%	Resized conventional plus supplemental boilers

FIGURE 4

estimates. Results to date of these efforts are encouraging. The cost goals which are estimates of the allowable installed costs required for both early entry and mature markets seem to be obtainable. However, it must be pointed out that the real cost goals will be set as a result of the ongoing market and business assessments by more than 25 utilities. It is their input that will determine the cost viability of onsite fuel cells in the gas industry.

The second phase of the technology development effort, which is presently ongoing, is performing the development necessary to advance the technology of specific components and subsystems. Particular attention is given to performance, reliabilty, maintainability, and cost. Increases in stack performance; higher efficiency inverters; standardized heat exchangers, pumps, and blowers; single-board microcomputer system logic; more reliable cooler arrays; and better performance and more tolerant reformer catalysts are some of the ongoing efforts. It must be kept in mind that a full 40kW fuel cell with heat recovery has been successfully run in the laboratory for over 7,000 hours, units are now being run successfully under real world conditions, individual short stacks have been run in excess of 25,000 hours and several single cells have been run between 50,000 and 100,000 hours. The basic technology is sound, the objective of this effort is to reduce fuel cell costs. Therefore, all these efforts are measured in cost savings potential to the fuel cell.

Onsite Fuel Cell Users Group

In 1980, it was decided that the gas industry must organize a group of utilities interested in promoting and pursuing the onsite fuel cell Energy Service concept. Thus, a gas industry fuel cell users group was formed to provide an overall policy guidance for participating utilities and to allow a forum for assessment of specific business issues common to many utilities. The purpose of organizing this users group was to ensure that the industry is addressing adequately the business, marketing, regulatory, legal, and technical issues that will be key to any long term decisions regarding fuel cells. Today there are over 35 member gas and combination utilities. It is through the Onsite Fuel Cell Users Group that the manufacturers of fuel cells can better understand the market potential and industry needs regarding an onsite fuel cell Energy Service. The data generated from the field test project activities and the technology development efforts are essential input to each user group member utility.

When all of the business planning, market projections, and venture analysis factors have been properly considered, a fuel cell users group utility can feel confident that its data base for decision making is as sufficient to make a prudent business decision relative to fuel cells as the combined knowledge of the industry could muster. The sum of this knowledge and the utility decisions could shape a changing future for the gas industry and the nation's Energy Service structure.

FUEL CELL POWER PLANTS FOR ELECTRIC UTILITIES

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Background

During the decade of the 70s, the phosphoric acid fuel cell (PAFC) matured from an engineering curiosity to a multimegawatt utility demonstration plant.

This was made possible by a number of important technological advances specific to the PAFC. Among them:

- power densities (at constant voltage) were increased threefold- from 70 milliwatts/cm^2 to over 200 milliwatts/cm^2 (Figure 1),
- catalyst loadings were reduced by nearly an order of magnitude- to < 1 mg/cm^2 of cell, and
- lifetimes were increased by more than an order of magnitude from thousands to tens of thousands of hours (Figure 2).

Figure 1. Progress in Phosphoric Acid Fuel Cell Technology

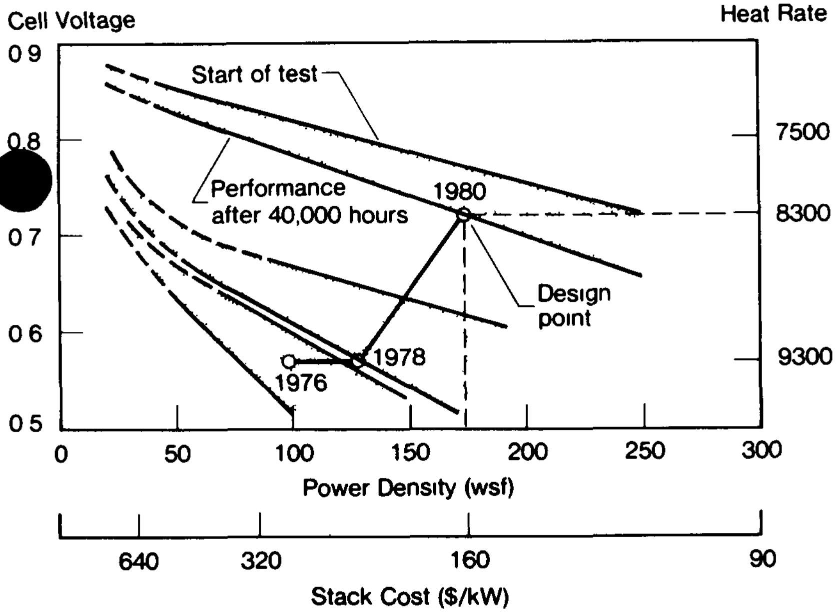
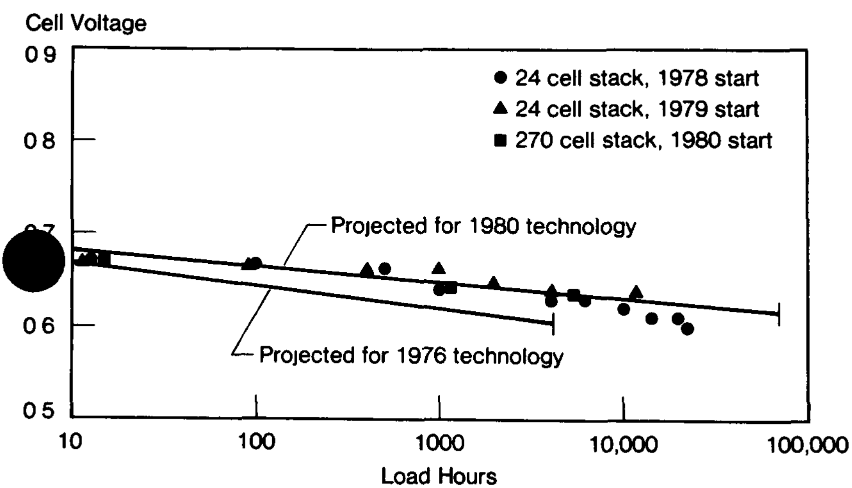
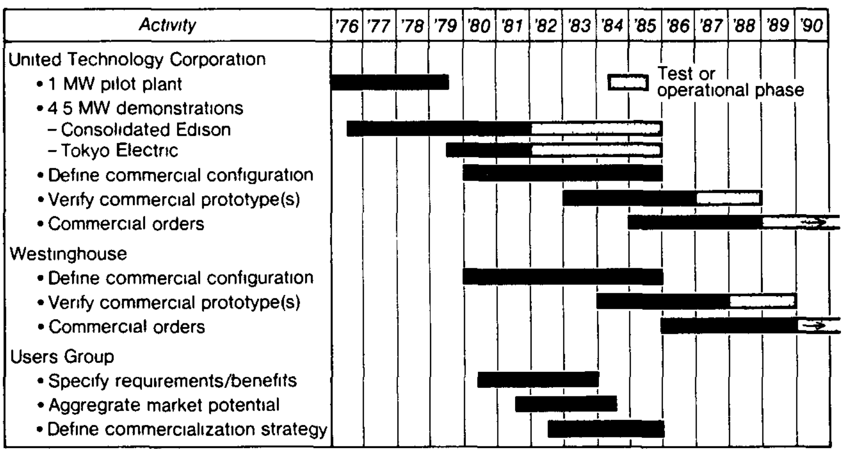


Figure 2. Cell Stack Performance vs. Operating Time



These advances in performance resulted in significant improvements in power plant cost and in lifetime, and led the utility industry to consider PAFC power plants as viable electric generators that could operate on utility systems for 10-20 years. Consequently, a series of coordinated activities (Figure 3) were put in place to expedite the commercial availability of electric utility PAFC power plants that are modular, efficient, environmentally acceptable and can be dispersed on utility systems (sited close to the load) to reduce the need for large expenditures on new central station power plants and/or transmission facilities. It is expected that commercial units will be available by the latter 1980's.

Figure 3. **DISPERSED PHOSPHORIC ACID FUEL CELL PROGRAM**



The 4.5 MW demonstrator, produced by United Technologies (UTC), is intended to verify the sitability and operability of fuel cell power plants. Installation on the Con Edison system in New York City is completed, the process and control test is underway and power is expected to be generated into the grid in 1983. A second 4.5 MW unit has been purchased by Tokyo Electric Power Company. It is proceedin to approximately the same schedule as the Con Edison unit.

The 4.5 MW demonstrators are based upon the technology that was available when the projects were commissioned in 1976 and 1979 respectively. Thus, there is a need to upgrade the demonstrator design to include the latest performance and life improvements as well as to accomodate recent engineering innovations, the learning obtained from the 4.5 MW demonstrators, and specific advice from utility advisors assigned to assist in defining the industry's needs through the Fuel Cell Users Group (FCUG).

Consequently, commercial configuration design and development efforts are underway at both UTC and Westinghouse (W) supported by the Electric Power Research Institute (EPRI), Department of Energy (DOE), and Tennessee Valley Authority (TVA). Table 1 compares the projected characteristics of the commercial configuration with those of 4.5 MW demonstrators.

Table 1
Projected PAFC Power Plant Characteristics

	4.5-MW Demonstrator	*Commercial Units*
Module Size (MW)	4.5	7.5 (W), 11 (UTC)
Fuel	Naphtha, natural gas, SNG	Naphtha, natural gas, clean coal-derived liquids and gases
Efficiency (%) (based on higher heating value)	≃ 37	≃ 41
Capital cost (1981 $/kW) (including IDC and installation, based on 1500 MW/yr prod.)	≃ 950	≃ 600
Projected life (yr)	≃ 1	20

The thrust of the efforts to develop and design commercial-quality power plants include:

- simplification to increase both maintainability and reliability while reducing cost,
- use of commercial components to reduce cost and repair time,
- performance improvements in the fuel cell stack to improve efficiency and lower costs, and
- fuel flexibility.

The results to date have been impressive. For instance, UTC's commercial design has 35% fewer parts than the 4.5 MW demonstrator; it uses commercial heat exchangers and turbocompressors; and it will use larger cells ($10 ft^2$ versus $3.7 ft^2$) capable of operating at higher pressure/temperature and consequently able to produce the performance commensurate with an 8300 Btu/kWh heat rate.

The question of fuel flexibility was addressed in a TVA sponsored project (conducted by UTC) that determined the equipment modifications required to operate the commercial power plant on a wide range of coal-derived fuels and to estimate the impact of these modifications on power plant performance and capital cost.

Table 2 summarizes the impacts.

Table 2.
Impacts of Retrofitting a Fuel Cell
Power Plant for Use With Alternative Fuels

Fuel	*Heat Rate (Btu/kWh)*	*Capital Cost (%)*
Methane (baseline)	8350	0
Medium Btu gas		
With methane	8360	+0.4
Without methane	8350	+4.3
Methanol	8210	+1.0
Hydrogen	8100	+1.1

Source: TVA

This study concluded that the power plant could be fuel flexible. Modifications to convert to alternative fuels are not extensive and are retrofittable. The use of coal-derived fuels will have no impact on power rating and only a slight impact on either heat rate or capital cost.

A significant element of the coordinated program is the involvement of the Fuel Cell Users Group (FCUG). The FCUG is comprised of about 50 utility organizations. Its activities include:

- establishing the applications and benefits of PAFC power plants
- serving as a surrogate user in interactions with the developers to establish requirements and specifications
- providing information to other utilities, funding organizations, etc.

Since its formation in April 1981, the FCUG has identified important fuel cell benefits and their value ($/kW); identified more than 300 potential early users of the PAFC power plant; completed a market assessment; developed a fuel strategy; and provided critical information to the manufacturers regarding fuel cell performance/specification requirements.

Table 3 summarizes the benefits that a utility might accrue from the fuel cell's unique characteristics and the FCUG's perception of the value of those benefits.

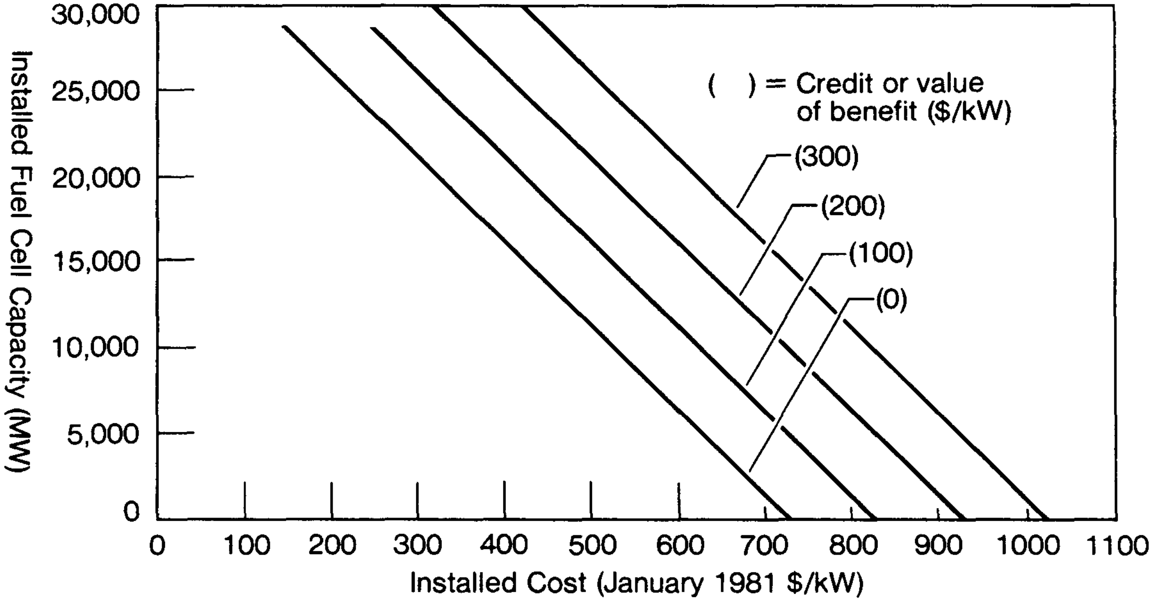


Figure 4. Aggregate market estimate of twenty-five utilities over 20-year period.

Table 3.
Value of Benefits to Be Derived
From Fuel Cell Power Plants

	Value ($/kW)		
Benefit	*Low*	*High*	*Average**
Air emission offset	0	217	11
Spinning reserve	0	33	8
Load following	0	52	7
VAR control	11	22	12
T&D capacity	0	247	59
T&D energy losses	8	35	15
Cogeneration	0	442	56

*Average of values selected by 25 utility planners

A novel approach to assessing the electric utility market for fuel cells was recently completed under FCUG direction. This effort utilized a utility generation expansion model and methodology to determine the penetration of fuel cells in 25 electric utilities. These 25 utilities represent about 15% of the electric energy produced in the U.S. Figure 4 portrays the results of this effort. This figure suggests that with a credit of $100-200/kW and an installed cost of $600/kW, there would be a penetration (over the next twenty years) of between 11,000 and 16,000 megawatts for the 25 utilities that participated in the study, or between 70,000 and 100,000 megawatts for the U.S. (assuming that the 25 utilities are typical). Even at $800/kW and credits of $100-200/kW, there could be a significant market. These results are preliminary and will vary considerably as external assumptions such as fuel price, load growth, cost of alternative generation, etc., are varied. Nevertheless, they do represent the best estimates of the involved utilities at this time and do provide the first truly credible fuel cell market estimates.

These results suggest that if the coordinated efforts to develop a commercial fuel cell power plant are successful in approaching the cost goals, then fuel cell power plants could be deployed by utilities in significant numbers.

THE 4.8 MW FUEL CELL POWER PLANT - VALUE OF A TECHNOLOGY DEMONSTRATOR

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The concept of producing electricity directly by an electrochemical process in a fuel cell has been known for over a century. It was first demonstrated in England by Sir William Grove in 1839; however, it remained little more than a laboratory curiosity until the space program. The inherent efficiency and simplicity of the fuel cell led to the development of the reliable fuel cell electric power systems which were used in the Gemini and Apollo space vehicles.

Many of the fuel cell characteristics such as efficiency, modular construction and almost no polluting emissions that made this type plant appealing for space aplications were also attractive to some electric utilities. The fuel and output power requirements for elecric utility applications are, however, different from those for space vehicle use. Therefore, considerable research and development was required to adapt the fuel cell concept to utility use. In the early 1970's a group of electric utilities initiated a research and development program to determine the potential of fuel cell technology for commercial electric power generation. That program led to the design and manufacture of the 4.8 MW dc (4.5 MW ac) fuel cell demonstrator which is now installed in New York City on Con Edison's system (Figure 1).

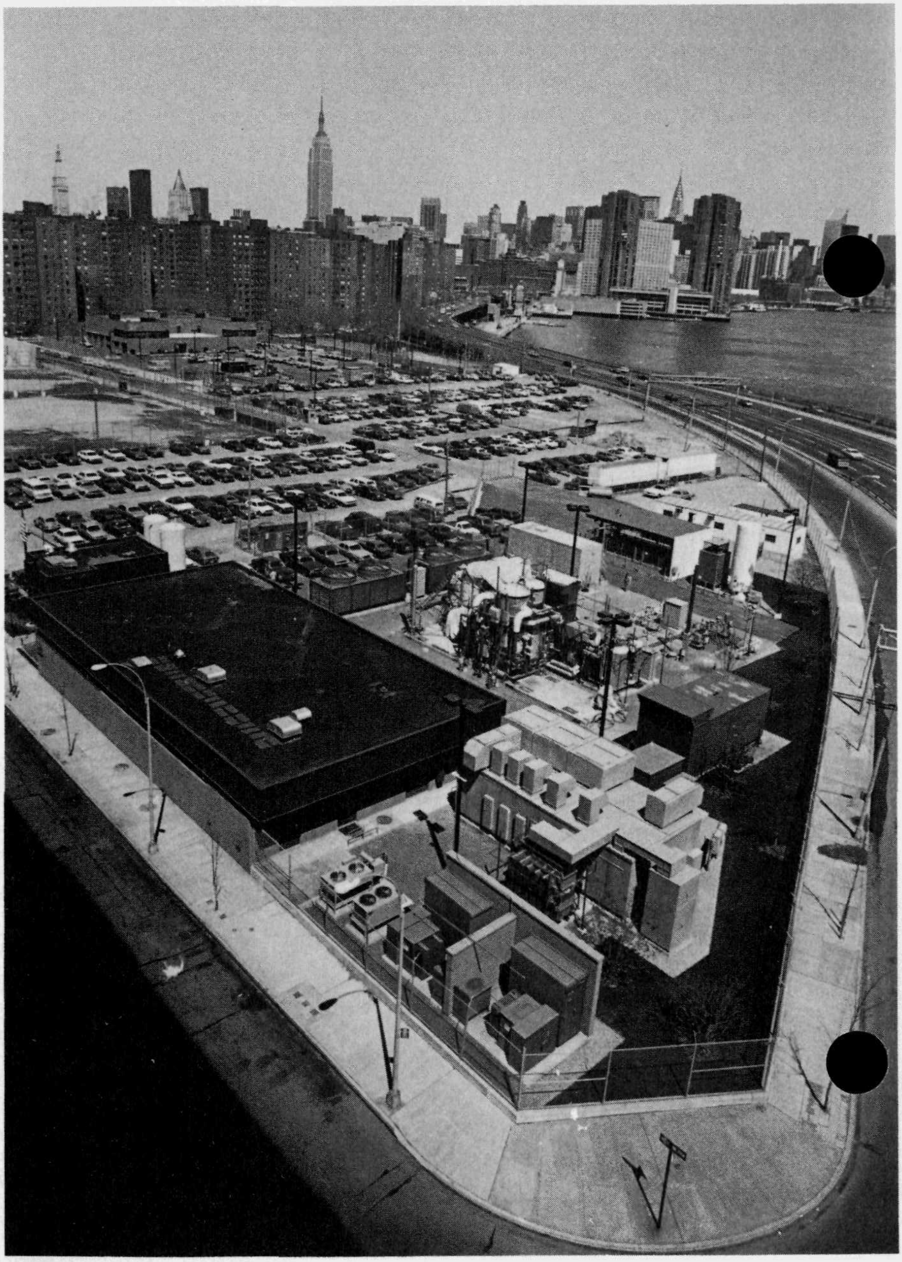

Figure 1. 4.8 MW Fuel Cell Demonstrator.

Experience gained during the manufacture, installation and initial testing of the 4.8 MW unit has validated the need for demonstration plants when developing new technologies. That experience is now being applied in the design of commercial configuration units.

HOW A FUEL CELL WORKS

A fuel cell consists of two electrodes separated by electrolyte which transmits ions but not electrons. The Fuel cells in the 4.8 MW Demonstrator use a phosphoric acid electrolyte. The fuel, a hydrogen-rich gas, is supplied to the anode, where hydrogen is dissociated into hydrogen ions releasing electrons to the anode. The hydrogen ions migrate through the electrolyte to the cathode, where they react with oxygen (from the air) and electrons to form water, in the form of steam. The electrons produced on the anode flow through the external electric cirucit providing direct current electric power.

The first electric utility fuel cell power plant consists of three major subsystems (Figure 2): fuel processor, fuel cell power section, and power conditioner (inverter). The fuel processor converts a conventional hydrocarbon fuel such as a light distillate or natural gas, to the hydrogen rich gas that can be used by the power section. The power section contains the fuel cells which produce direct current electricity as previously described. The water formed by the electrochemical reaction in the fuel cells is recycled and used for processing the fuel. The inverter converts the direct current electricity to alternating current compatible with the electric utility bus.

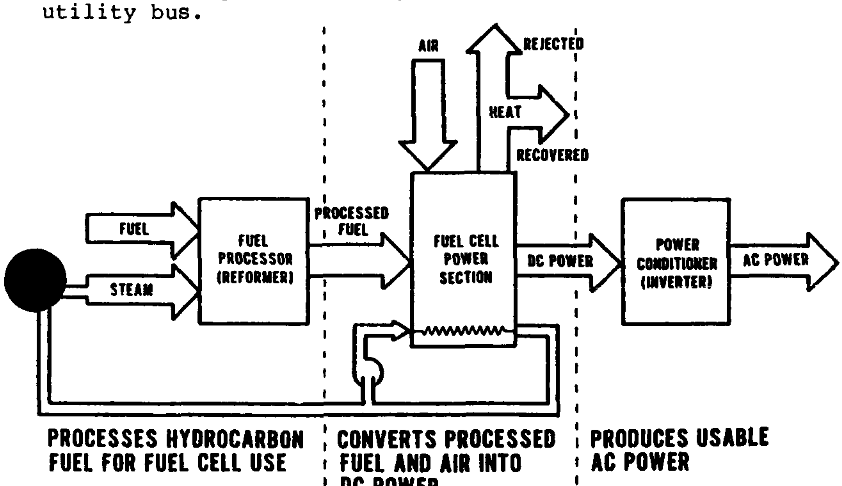

Figure 2. Fuel Cell Power Plant Schematic.

UTILITY INTEREST AND PROGRAM

Fuel cell power plant characteristics which could be attractive to electric utilities include: high fuel efficiency, modular design and environmentally clean emissions.

In a fuel cell the oxidation reaction of the fuel is forced to occur through an electrochemical path which causes most of the energy to be released directly in the form of electrical energy. This direct conversion of the fuel's energy into electrical energy results in a higher conversion efficiency than can be obtained in conventional thermal power plants.

Further, by the nature of the electrochemical process involved, the efficiency of the fuel cell power plant is determined chiefly by the voltage of the individual cell. This means the efficiency of a fuel cell power plant is (to a degree) independent of the size of the plant. Consequently, fuel cell plant size can be conveniently chosen for economic mass production without incurring a performance penalty

The essentially size independent efficiency feature of fuel cells permits factory manufacture and assembly of power plants into truck transportable modules which will minimize final field assembly time and costs. In addition the small size of these modular plants, should afford greater ease of siting and the ability to increase utility system capacity by small increments, thus minimizing the capital outlay necessary to respond to load growth.

The principle emissions from the fuel cell power plant are carbon dioxide, water and heat; the nitrogen and sulfur oxides and particulate emissions being considerably lower than current Environmental Protection Administration requirements. Fuel cell power plants are also expected to be quiet because they do not have many of the rotating machinery components which are major noise sources of conventional power plants. In addition, a minimal water supply is required because the water formed in the fuel cell's electrochemical process is continously recovered and used for the fuel processin

Fuel cell power plants also have a number of beneficial operating characteristics. They have a high fuel efficiency over the full operating load range, rapid response to load changes, the possiblity for independent control of real and reactive power using the plant's inverter, and minimum fault-current contribution.

Recognizing the benefits of fuel cell power plants, ten electric utilities joined with United Technologies Corporation (UTC) (then the Pratt and Whitney Aircraft Corporation) in 1971 to analyze the potential of fuel cell technology for commercial electric power generation. This evaluation led to the FCG-1 program which started in 1973 and was sponsored by UTC and nine utilities (Boston Edison, Con Edison, Consumers Power, New England Electric System, Niagra Mohawk Power, Northeast Utilities, Philadelphia Electric, Public Service Electric and Gas, and Southern California Edison). The program included the manufacture and test of a 1 MW pilot unit at UTC's facility in South Windsor, Connecticut. This unit was electrically paralled with the Northeast Utilities' electric system. When the operational testing phase of this program was completed in 1977, the unit had successfull operated for more than 1,000 hours and generated about 700,000 kilowatt hours.

ELECTRIC UTILITY FUEL CELL DEMONSTRATOR

In June 1976 the United States Department of Energy's predecessor, the Energy Research and Development Administration (ERDA), the Electric Power Research Institute (EPRI) and UTC agreed to jointly fund the development and manufacture by UTC of a 4.8 MW demonstrator unit for test on a utility system.

The Empire State Electric Energy Research Corporation, the New York State Electric Energy Research and Development Authority and two other electric utilities, Niagara Mohawk Power Corporation and Northeast Utilites, joined Con Edison in a joint venture to support hosting the fuel cell demonstration project in New York City. Several potential site locations were evaluated. The present site in lower Manhattan at 15th Street and F.D.R Drive adjacent to the Company's East River power station, was selected to demonstrate ability to site the fuel cell in a densely populated urban location.

Con Edison and its partners submitted their proposal for siting the fuel cell demonstrator in New York City to ERDA in May 1977, and Con Edison was selected as the host utility in July 1977. In accordance with the joint proposal of Con Edison and its partners, Con Edison was to:

- develop a plant site including foundations, roads and control building (Figure 3);
- provide and install auxiliary equipment;
- install the fuel cell power plant including mechanical and electrical interconnections;
- perform subsystem checkouts;

o conduct the acceptance, validation and supplemental test programs.

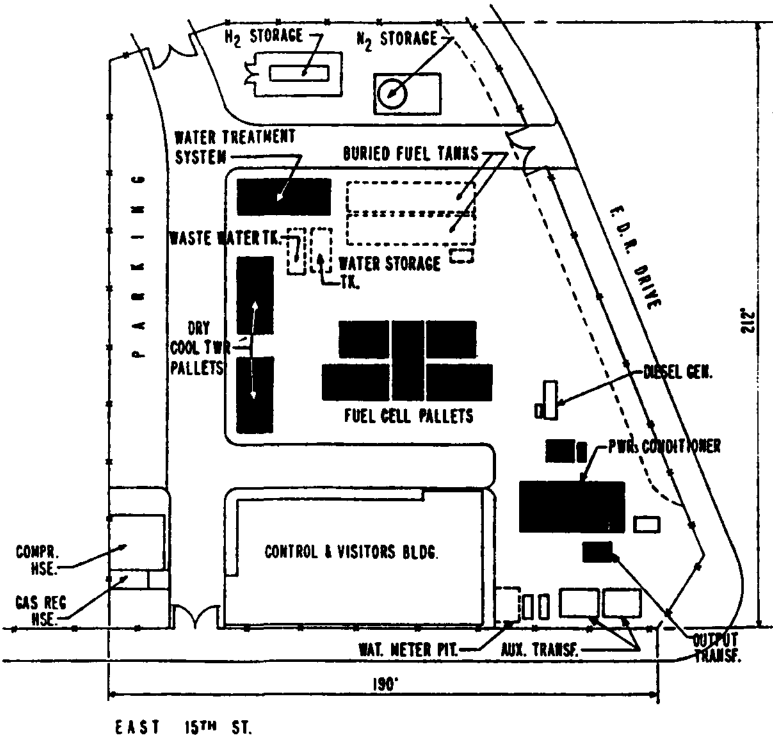

Figure 3. 4.8 MW Fuel Cell Demonstrator Site Plan.

Site construction for the project began during November 1978 and in May 1979 the first modular elements of the power plant, the dc/ac inverter and output transformer, were delivered and installed. When construction started completion of the construction phase was scheduled for January 1980. However, fabrication problems associated with the new design, compact, formed plate heat exchangers resulted in a major delay in deliveries of the fuel processing and air handling modules to the site. Consequently it was not until the end of 1980 that all equipment, except the fuel cell modules was installed and site construction essentially completed.

During January 1981 following very cold weather, excessive amounts of make-up nitrogen were suddenly required to maintain the continous nitrogen purge which protected catalytic beds in the fuel processing equipment. An extensive investigation found that five of the plant's thirteen formed plate heat exchangers had developed leaks. Locating the leaks involved pressure testing all major components at the site and was extremely difficult and time consuming due to poor accessability and lack of isolation valves for the palletized equipment. Identifying and correcting this problem resulted in a seven month delay in the program schedule.

The heat exhangers, originally designed for pneumatic testing prior to Con Edison being selected as the host utility, were hydrostatically tested as a licensing requirement of the New York City Fire Department. It was determined that the leaks were caused by freezing of residual water remaining in the heat exchanger after the shop pressure testing. Computer studies had erroneously led to concluding that stresses caused by freezing of this residual water would not cause damage; therefore, the equipment had been shipped to the site knowing that some water remained in the heat exchangers.

Three of the five damaged heat exchangers had large internal leaks and they were replaced with available spares. One heat exchanger had a minor overboard leak and was repaired by welding at the site. The fifth heat exchanger had developed a small internal leak, fuel to fuel, which would not affect plant operation and, therefore, this heat exchanger was not replaced.

In November 1981, following the heat exchanger replacement and repairs, the Fuel Cell Process and Control (PAC) testing was started. PAC testing is intended to checkout the fuel processing, thermal management, water treatment and control systems using special test equipment in lieu of the fuel cell stacks. By March 1982 PAC testing had progressed to the point where the plant was ready for an attempt to produce hydrogen from naphtha. The test was started and proceeded through system pressurization, light-off of the four naphtha torches used to bring the reformer up to temperature, completion of heat-up and initation of the steam reforming process sequence. A few minutes later the plant automatically shutdown because the fuel/steam ratio did not meet the operating criteria. After the plant shutdown, the normal pressure of the nitrogen inerting blanket for the fuel processing system could not be maintained. The nitrogen leak was subsequently traced to the reformer.

Inspection revealed that the tops of four of the thirty seven reforming tubes, which contain the catalyst beds in the reformer pressure vessel assembly, were severely damaged. Holes were burned through the outer walls of three of these tubes several inches below the tube tops. Insulation inside the reformer vessel dome above two of the four torches contained carbon formations and some insulation had become detached. The two associated torches were severely burned and the outer barrel of one was cracked and partially melted. The nozzles of these two torches were completely plugged with carbon and the nozzle of one of the other two torches was partially blocked. Chemical analysis of the dome insulation material found it acceptable for the 2300°F material specified. However, the observed shrinkage of the insulation material indicated that it was subjected to approximately 2500°F. Eddy current testing of all tubes indicated that tube damage was limited to the areas of visual damage.

The buildup of heavy carbon deposits on the dome insulation and the formation of carbon clinkers directly above the two torches was due to a combination of poor vaporization of the high flashpoint naphtha (used to obtain approval of naphtha) and maldistribution of air to the reformer vessel quadrants where the torches are located. The carbon clinkers, in turn, directed the poorly vaporized fuel downwards towards the nearby tubes. The fuel burned near the tube walls causing high temperatures and subsequent tube burn through.

The necessary repairs and modifications to the reformer included:

- Replacing the naphtha burning, reformer heat-up torches with new, natural gas fueled torches to eliminate possibility of poor vaporization;
- Adding a 6 inch spacer ring between the reformer dome and the reformer vessel to provide more distance between the torches and the reformer tube tops and more space for combustion of the fuel;
- Reinsulating the reformer dome, adding outer layers of 2600°F insulation, and applying a hard insulation coating in the areas around the torches;
- Recharging the four damaged tubes with new catalyst and welding on new tube top castings;
- Modifying the reformer main air distributor assembly and individually metering the fuel and air going to each of the four new gas torches to provide improved air flow distribution and better control.

After completion of the repairs and modifications, the reformer vessel, tubes, and reassembled piping systems were pressure tested to insure their integrity. PAC testing was restarted in November 1982. The reformer problems had resulted in a program delay of about eight months.

INTERIM CONCLUSIONS

Although the Demonstrator will not produce power until mid 1983, several interim conclusions have been made and improvements incorporated into an 11 MW commercial design.

The 4.8 MW Fuel Cell Demonstrator is located in very densely populated Manhattan. This site has been found acceptable by the local community board and by the New York City Fire Department which acted as the City's technical licensing agency. Therefore, we conclude that this type of power plant can be sited in densely populated urban areas.

Short lead time and over the road delivery of the modular sections of the fuel cell power plant have been confirmed. Ease of field construction associated with this modular power plant has also been demonstrated.

As a result of the required replacement and repairs of heat exchangers, the needs for better equipment accessability and subsystem isolation have been identified. Design improvements to accommodate these needs are being factored into the commercial plant design. (Figure 4).

CHARACTERISTIC	DEMONSTRATOR	COMMERCIAL
Capacity, MW	4.5	11.0
Heat Rate, BTU/KWH	9300	8300
PAC Module Pallets per MW	1.1	1.5
Cell Stacks per MW	4.4	1.6
Piping Bellows	Yes	No
Heat Exchangers	Formed Plate	Shell and Tube

Figure 4. Comparison of Demonstrator and Commercial Design.

In comparison with the 4.8 MW Demonstrator a large percentage of the components will be eliminated from the dc module. In part this will be due to using larger fuel cells. Each cell is anticipated to have an area of 10 square feet as compared with the 4.8 MW Demonstrator's individual fuel cell area of 3.7 square feet. There will be about 18 fuel cell stacks for the 11 MW plant compared to 20 fuel cell stacks for the 4.8 MW Demonstrator. The 11 MW plant will consist of a larger number of equipment module pallets with considerably reduced complexity. Increased pallet spacing will eliminate the need for piping bellows and provide room for maintenance. Commercially available components such as turbo-compressor, contact coolers, and shell and tube heat exchangers will be utilized. All of these features will result in improved maintenance and repair capability, and should maximize plant availability. The efficiency of the 11MW plant will also be improved. Its design heat rate is 8300 Btu/Kwh.

FUTURE ACTIVITIES

PAC Testing should be completed by the spring of 1983 and the fuel cell modules will then be installed. After fuel cell stack installation and final unit check-out a 200 hours acceptance test will be conducted to verify the plant's stable operation, emissions and operating modes and parameters. This will be followed by a 2000 hour validation test. The validation test is designed to verify performance characteristics and obtain operating data under daily load cycles. This test will require approximately six months.

The validation test is scheduled to be followed by the supplemental test phase of about 4,500 operating hours. This test phase, is intended to investigate use of the unit's inverter for power factor correction without the power plant in operation, evaluate unit warm-up time and energy requirements for a variety of operating modes and provide further information on the plant's endurance. The supplemental test phase is scheduled to run about seventeen months.

Completion of the 4.8 MW Fuel Cell Demonstration project, as presently planned, would occur by the end of 1985. The Con Edison consortium proposal to ERDA/EPRI however, identified a number of possible follow-on efforts and work is now beginning to better define these and other possible projects to expand the data obtainable from the 4.8 MW unit. These efforts include demonstration of the power plant's ability to utilize coal derived liquid fuels, to recover and use reject energy, and upgrade the unit's capabilities by retrofit of advanced components such as improved, longer-life cell stacks.

Preliminary studies have been conducted to identify the modifications and costs required to operate the 4.8 MW unit on methanol and to utilize the reject energy to heat the feedwater to the East River Station boilers of the Con Edison district steam system.

CONCLUSION

Considerable knowledge has been learned from the construction and early testing of the 4.8 MW unit. Clearly this unit has verified the need for a demonstration plant during the development of this new technology. Additional experience gained during operational testing will not only demonstrate the benefits of fuel cell power plants but will undoubtedly lead to further improvements in commercial plant design. We conclude that the 4.8 MW unit is providing a necessary and significant step toward commercialization of fuel cell technology for electric utility use during this decade.

AN NSSS SUPPLIER'S VIEW OF INDUSTRY REVITALIZATION

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INTRODUCTION

Although nuclear power has proven to be a reliable, economical, and safe source of energy, it is clear that the domestic nuclear option is in serious trouble; even to the extent that it is dying a slow death. While it is true that our industry has a generous share of problems, we at Westinghouse believe that nuclear power is and will remain a viable and necessary part of the national energy program. However, if this belief is to be realized and the nuclear industry revitalized, it is imperative that some changes are made.

There are many contributors to the absence of orders for new nuclear power plants and the cancellation of proposed plants. These contributors actually run the gamut from low electrical demand to anti-nuclear activities to uncertainty in licensing to problems within the industry itself. However, the major problem areas of concern that must be addressed to achieve industry revitalization involve:

- Plant design,
- Plant construction, and
- Plant licensing

Each of these areas can and will be discussed in their own right, but it must be realized that each area interfaces significantly with the other two areas. Problems that arise in one area typically manifest in the other areas.

PLANT DESIGN

The problems and concerns dealing with plant design for industry revitalization are obviously geared to the next generation of nuclear power plants. The technology for the plant designs being licensed and built today is actually a decade old. New generation nuclear power plant designs should be based upon major improvements in economics, operability, and availability.

The cost of nuclear power is already lower than that for coal, but there are opportunities to substantially increase the nuclear advantage. The most important economic issue is capital cost; it can best be improved by simplifying and expediting the construction phase of the project. Major improvements in capital costs can also be realizable from: (1) reduction of the potential for changes due to licensing requirements; (2) better definition of design at the beginning of a project; and (3) application of new computer technology in design and project management.

New opportunities also exist to improve another large economic factor, fuel costs, through use of advanced fuel and core designs which generally cannot be incorporated into existing plants and, consequently, have not yet been applied. The use of a larger reactor core will also improve neutron economy and at the same time increase the margin to licensing limits and provide operating flexibility.

The economics and convenience of operation are improved when plant availability is increased and there is generally a further benefit in reduced radiation exposure. Considering the high level of attention given to quality assurance in the design and manufacture of nuclear equipment, the generally higher technology applied to design, and the strong economic incentive to keep the low fuel cost unit on the line, we should expect a substantially higher availability than coal but advanced designs should widen the gap as field data are brought to bear on equipment reliability and operating experience is factored into plant designs.

With regard to safety and economic risk new opportunities are provided by the rapid advances in microprocessor technology, better understanding of human factors, and the burgeoning use of probabilistic risk assessment. These will result in improved control room designs to reduce the probability of man/machine interface problems similar to those experienced at Three Mile Island and new bases for the plant designer to improve safety. Plant designs which are more tolerant to malfunction and which facilitate recovery following equipment damage can reduce economic risk to utilities and their customers.

In 1977, Westinghouse embarked on a major development effort directed toward the establishment of a new generation nuclear power plant design based upon our assessment that major improvements in economics, operability, and reliability were achievable compared to present state-of-the-art designs. This development effort to date has reinforced this assessment and has also indicated that financial risk reduction and safety improvement are strongly related through the mutual objective of accident avoidance and design "forgiveness".

Westinghouse has entered into a major cooperative design development effort with a Japanese vendor directed toward the establishment of final design detail for this Advanced Pressurized Water Reactor (APWR) design and completion of an extensive test program by 1985. Westinghouse has also initiated a domestic licensing program with the NRC for the APWR design. This program ties together the concepts of an advanced design with nuclear power block standardization and one-step licensing.

PLANT CONSTRUCTION

Lead time for nuclear power plants in the United States has grown to an undesirable 12 to 13 years. This is largely due to unwarranted delays being experienced in plant completion. Overseas, in France and Japan, for example, licensees of U.S. companies build plants using our designs in about six years, a figure that was also normal for plants in the U.S. in earlier years.

A track record of delays in plant completion obviously provides no assurance to a utility that a plant can be constructed within a reasonable time. However, these delays also significantly increase the cost of the plant because of the interest accrued during construction. In addition, the quality of the product can deteriorate due to the large turnover of personnel over such a long period, and equipment can deteriorate during a lengthy construction process.

Design standardization has tremendous potential in shortening plant construction times. The standardization concept is not new, but it has enjoyed very limited success since its introduction in 1973. One of the key reasons for this limited success has been the industry's approach to standardization (i.e., many standard NSSS designs that mate with many standard BOP designs).

A nuclear power plant should not be viewed as merely a collection of equipment that can be piecemealed together. It is a vast amalgamation of components, systems, operations, and people. The current domestic implementation of nuclear power standardization involves a myriad of interfaces having major safety implications. The management of the design and construction of a nuclear power plant is spread among several organizations including the utility, the architect-engineer, and the NSSS vendor. Problems which are identified in one organization do not necessarily filter quickly into the other affected organizations. In a similar sense, requirements or interfaces placed on one organization by another organization are not necessarily understood or completely documented as being implemented. The end result is a time consuming process that requires a tremendous and often repetitively wasteful use of our human resources to provide the appropriate safety assurance when implementing a design.

In short, while the industry has long recognized that standardization is a major input to reducing construction times, we have not been implementing the concept properly. It is time that the industry recognize the Nuclear Power Block (NPB) concept to implement standardization. The NPB is, in a hardware sense, that block of equipment and buildings which distinguishes a nuclear power plant from a fossil power plant, as illustrated in Figure 1. However, the NPB is also, in a software sense, total responsibility for plant construction, quality assurance, plant licensing, and plant startup.

A benefit of the NPB concept is that one single organization is responsible for all safety aspects of the plant design and construction. The myriad of interfaces having major safety implications are eliminated.

As a method of implementing the quality assurance aspects of the NPB concept, the process of utilizing a Designated Inspector Program (similar to that utilized in the aviation industry by the FAA) involving detailed system and component checklists should be pursued.

Recognizing the problems associated with a redefinition of current scope boundaries, Westinghouse believes the NPB concept is the method to achieve design standardization and reduced construction lead times, as well as design assurance from a safety standpoint. Properly defined, the design, licensing, and supply of the NPB should meet the needs of each of the principals involved without detracting from the unique design and procurement needs of the individual utility.

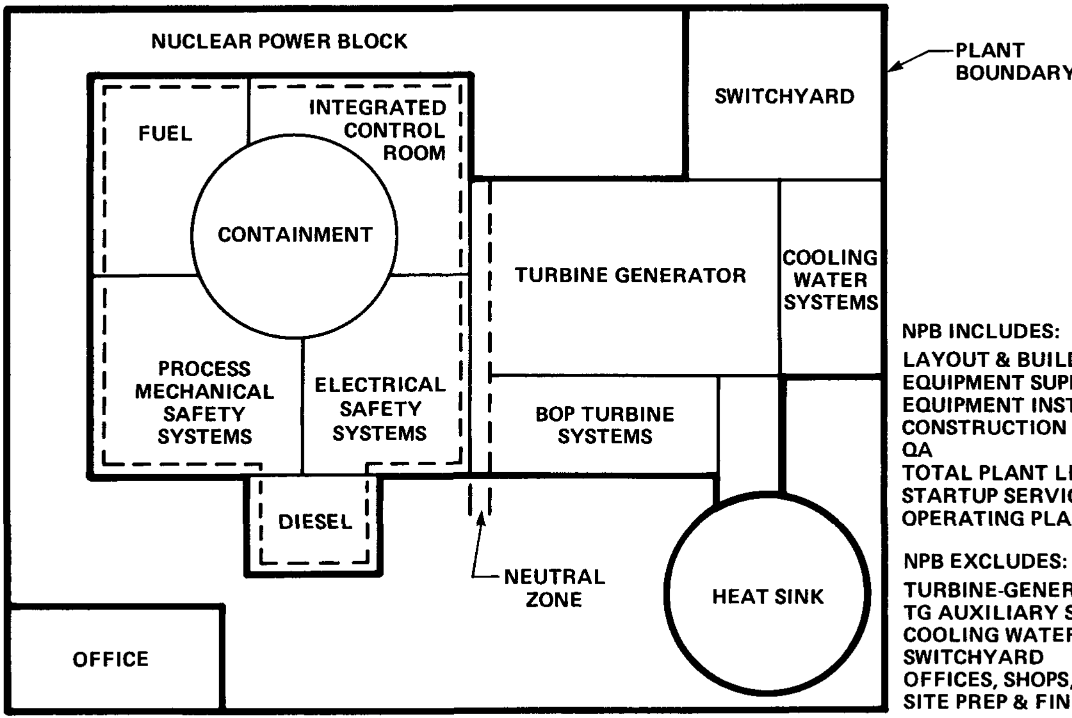
Westinghouse is pursuing the NPB standardization concept in relation to our APWR design and licensing program. All in all, we see this program as a major testing ground for many new design and licensing concepts geared to revitalizing the industry.

PLANT LICENSING

Currently the Atomic Energy Act provides for a two-stage facility licensing process. First, a utility must obtain a Construction Permit from the NRC, authorizing construction of the proposed facility at a specific site. This stage is focused on the preliminary plant design and the suitability of the site. A public hearing must be held by the NRC prior to the issuance of the Construction Permit.

The second stage of the process involves the issuance of an Operating License. A facility cannot be operated without first obtaining an Operating License from the NRC. This stage is focused on the final plant design and a public hearing must be held by the NRC prior to the issuance of an Operating License if one is requested by an "affected" person.

The two-stage licensing process was probably the prudent course to follow in the past when there were many unproven design concepts and many first-time nuclear plant applicants. However, in today's environment the two-stage process (in conjunction with plant design and construction) has lengthened the lead time for nuclear power plants to an undesirable 12 to 13 years. The licensing process contributes to



NPB INCLUDES:

LAYOUT & BUILDING DESIGN
EQUIPMENT SUPPLY
EQUIPMENT INSTALLATION
CONSTRUCTION
QA
TOTAL PLANT LICENSING
STARTUP SERVICES
OPERATING PLANT SERVICE

NPB EXCLUDES:

TURBINE-GENERATOR
TG AUXILIARY SYSTEMS
COOLING WATER SYSTEMS
SWITCHYARD
OFFICES, SHOPS, LABS
SITE PREP & FINISH WORK

FIGURE 1

the 12 to 13 year lead time in that:

- The Construction Permit review process must be completed prior to actually starting construction.

- The mandatory Construction Permit hearings and probable further hearings related to the Operating License can add a number of months or a number of years to the process.

- The preliminary and final design reviews performed by the NRC are duplicative and not only add unnecessary time to the process, but promote the wasteful use of human resources.

Streamlining the licensing process is, therefore a necessary part of our industry's revitalization. The one-step licensing process embodied in the DOE's proposed legislation is a necessary step toward regulatory reform. Briefly, one-step licensing is a process whereby a qualified utility would apply for a combined Construction Permit and Operating License based upon a preapproved site and plant design. Plant operation would be contingent only upon completion of certain prescribed tests and inspections. As shown in Figure 2, the potential time savings of a one-step versus a two-step licensing process are attractive (i.e., ∿ 7 versus ∿ 13 years).

In order for one-step licensing to be effective in streamlining the licensing process:

- A preapproved design must be a standardized total plant design (i.e., Nuclear Power Block concept) that is essentially final and has been certified by the NRC through rulemaking.

- A preapproved site (either through an existing site approval or an early site approval) must be within the envelope of sites utilized and certified for the preapproved design.

- A utility must demonstrate compliance with facility standards for training, emergency response plans, organization structures, physical security plans, etc.

A one-step licensing process would still provide the opportunity r public hearings related to a plant's design, siting, construction, d operation. However, the public hearing process must be controlled such that only legitimate contentions that have not be previously adjudicated are admitted by the hearing boards and panels. As stated most appropriately by James Tourtellotte (1) when referring to the current hearing process . . . "The practical result is that both the

(1) James R. Tourtelotte, "Nuclear Licensing Litigation: Come On In, the Quagmire is Fine", Administrative Law Review, Fall 1981, Volume 33, Number 4.

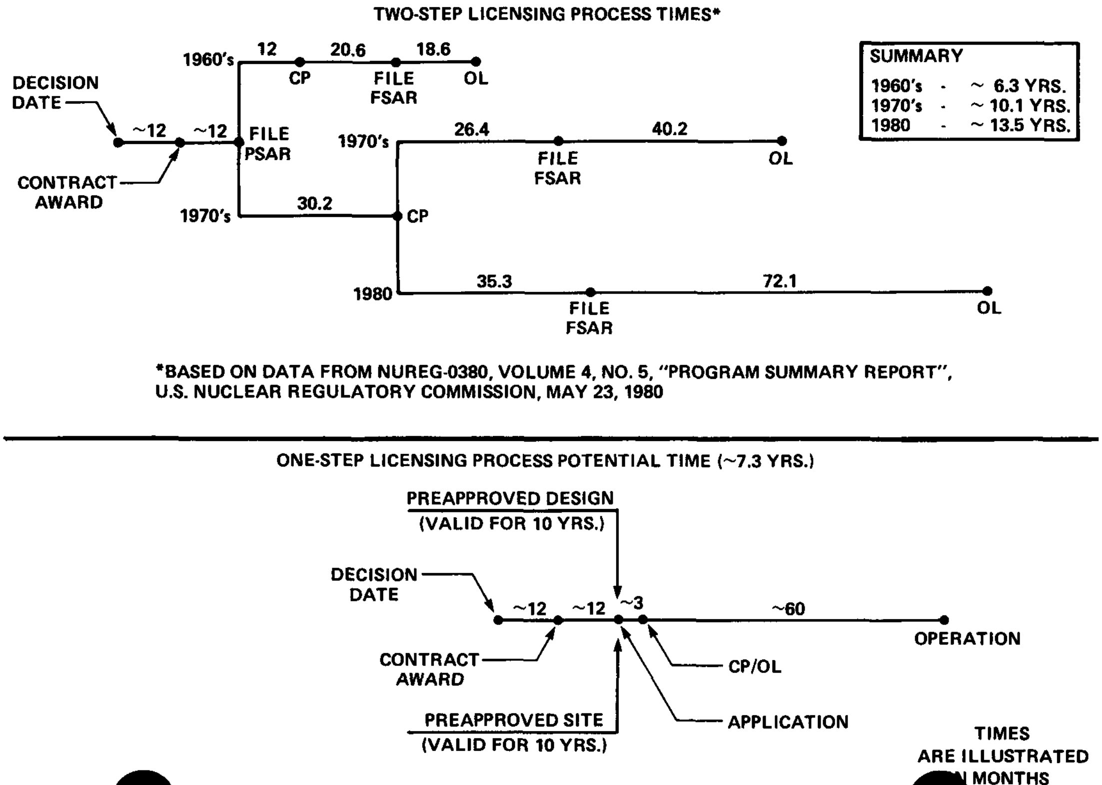

TWO-STEP LICENSING PROCESS TIMES*
SUMMARY
1960's - ~ 6.3 YRS.
1970's - ~ 10.1 YRS.
1980 - ~ 13.5 YRS.
DECISION DATE
CONTRACT AWARD
~12
~12
FILE PSAR
1960's
12
CP
20.6
FILE FSAR
18.6
OL
1970's
30.2
CP
1970's
26.4
FILE FSAR
40.2
OL
1980
35.3
FILE FSAR
72.1
OL
*BASED ON DATA FROM NUREG-0380, VOLUME 4, NO. 5, "PROGRAM SUMMARY REPORT", U.S. NUCLEAR REGULATORY COMMISSION, MAY 23, 1980
ONE-STEP LICENSING PROCESS POTENTIAL TIME (~7.3 YRS.)
PREAPPROVED DESIGN
(VALID FOR 10 YRS.)
DECISION DATE
~12
~12
~3
~60
OPERATION
CONTRACT AWARD
CP/OL
APPLICATION
PREAPPROVED SITE
(VALID FOR 10 YRS.)
TIMES
ARE ILLUSTRATED
MONTHS

FIGURE 2

NRC staff and the applicant must expend considerable time and resources to prove the intervenor wrong while the intervenor rests on pro forma contentions".

The DOE proposed one-step licensing process still leaves many questions unanswered (e.g., what level of design detail is both necessary and practical for standard design approval; and what portion of a nuclear plant should be standardized by a vendor and certified through rulemaking by the NRC?). Westinghouse however, is convinced that one-step licensing is one of the important keys to our industry's revitalization. In fact, the Westinghouse licensing program for our APWR design is intended for the application of a one-step licensing process. This program is currently scheduled to achieve design certification through rulemaking by 1987. Along the way this program will also provide the practical forum for completely defining one-step licensing requirements.

Future regulatory stability for both existing and new plant designs is another important aspect of plant licensing. An everyday part of life for an operating nuclear plant involves the constant fear of NRC mandated backfit. This fear is not caused by an unwillingness to make or at least evaluate change. The fear is that the backfit will be prescriptive both in its development and its implementation. A prime example of this situation was born in the aftermath of Three Mile Island when many utilities found themselves on the horns of a dilemma. Equipment suppliers were unable to deliver some hardware in time to support the NRC mandated implementation schedules, while the NRC was reluctant to entertain arguments to revise their implementation schedules. This situation was compounded by the NRC's initial unwillingness to hear any justifications for deviating from their technical requirements. The result was that the nuclear industry did not appear responsive on all fronts. The absolute necessity of having systematic evaluations of concerns and detailed planning before implementing resolutions was an important lesson learned from the post-TMI environment.

The more basic questions of "how safe is safe enough?" and "when should a particular plant be required to make a change?" must be answered if the industry is to achieve regulatory stability. The answer appears to be the development of a national safety goal for all nuclear plants or classes of plants. The safety goal concept is that every plant should be at some minimum numerical level of safety. Appropriate actions or "backfit" would have to be taken by all plants shown to be below that minimum level. Once a plant is at or above the minimum numerical safety level, future changes would only be required if the changes passed a specified cost-benefit test.

The national safety goal concept has brought to the licensing process a technological tool known as probabilistic risk assessment. This tool (which, as it's name suggests utilizes probabilities of occurrences for particular events or combinations of events that are supported by operating data) would be used to establish the numerical safety level for plants.

Regulatory stability for the next generation of new plant designs is expected to follow a somewhat different course. While the safety goal concept and the probabilistic risk assessment tool will still be utilized, a proposed NRC policy paper (SECY-82-1B) suggests that the safety goal will be set at a higher level for new plant designs. In addition, a new plant design must incorporate upfront those features determined to be cost-effective in resolving the numerous industry "unresolved safety issues" or "generic safety issues". The benefit or stability to be achieved by this upfront resolution process is assurance that the fundamental new design will remain relatively unchanged for a 10 year period, following a plant design rulemaking.

Westinghouse supports the NRC's proposed policy paper for new plant designs and we are currently implementing this policy in relation to our APWR design and licensing program.

SUMMARY

Nuclear industry revitalization obviously includes those steps necessary for nuclear power to regain its rightful share of the energy market in the United States. However, it must also include those steps necessary to ensure continued operation of existing plants. Westinghouse sees its role expanding and continuing through design, licensing, construction and initial startup and, equally important, throughout the operating life of the plant. In performing this role, Westinghouse is committed to be constantly learning from operating experience and incorporating feedback into the design, analysis, procedures, and training areas.

The problems that face the nuclear industry are not insurmountable and the industry can be revitalized.

EPRI's VIEW OF INDUSTRY REVITALIZATION

John J. Taylor
Director, Nuclear Power Division
Electric Power Research Institute

Although I did agree to present a paper on industry revitalization in a session entitled "Revitalizing the Nuclear Option," I object rather strongly to the term "re-vitalization." An electric generating system which is producing about twelve percent of the power in the United States and 25 percent of the power in Switzerland, Sweden, Belgium, and France, and making major contributions to electric power throughout the world doesn't need to be revitalized. Is not a system vital that still has almost as many plants under construction as are presently operating both in the United States and around the world? Is not a system vital that represents well over $100 billion dollars worth of utility investment in the United States alone and accounts for approximately half of all U.S. utility capital investment for 1982, or $14 billion dollars? Is not a system vital that has the most outstanding safety record in any major industrial activity? Is not a system vital that has the least environmental impact per unit of power produced than any comparable electric generating system built to date? Is not a system vital that has produced its electricity at a cost less than available alternates?

I would suggest that we in the industry are concerned about nuclear power's vitality for three reasons. First, we don't see a continued expansion of nuclear power in the near future after the expansion which was started in the '70s has been completed. Secondly, we are concerned that the full promise of nuclear power is not being realized: that it is intrinsically capable of higher reliability than we are experiencing, and of lower costs than we are experiencing. Finally, we are concerned at the high level of opposition to nuclear power which has grown over the last decade.

I would suggest that the second concern - lack of achievement of the full promise of nuclear power's capabilities - is the central concern and the one we in the industry should primarily address. If we address it successfully, the utility industry will opt for nuclear power expansion when base load electricity generation growth is warranted. Then, the economic basis for opposition to nuclear power will be removed and the emotional basis will, with time, wither away.

What we in the industry must do to allay this central concern can be described by two simply stated, although not easily attainable, objectives. First, the availability of the 75 plants in operation in the United States and their O&M costs must be improved. Secondly, the construction times and construction costs of the other 59 plants still under construction must be reduced. These are at this time the only two important objectives in nuclear power from the viewpoint of the utilities. All other issues, including future expansion of nuclear power capacity and the development of advanced nuclear power generation, are secondary.

Can nuclear plant availability be improved? The existing record demonstrates that improvement is achievable with the existing light water reactor systems. The bar graph in Figure 1 shows the average capacity factors of LWR nuclear power plants by country in 1981. We see that the United States is among the laggards in the light water reactor family, falling more than 20 points behind Switzerland, Belgium, Spain, the Netherlands, and Taiwan. If the average capacity factor of the U.S. was as high as Switzerland, the question of the economic advantage of nuclear power over all alternate base load electric generation would not even be asked. Other countries, such as Japan, have shown consistent improvement in plant availability. The capacity factor of Japanese nuclear plants has increased over the past five years by about 40 percent. By comparison, the United States capacity factors have slightly decreased.

Although I didn't have the 1982 data at the time these figures were made up, I now have the 1982 LWR worldwide capacity factors. The U.S. average has improved by 2.3% and has moved up to third from the last in standing. Japan has improved by a strong 13.2% and now averages 68.8%. France dropped 5.5% and moved behind the U.S. Switzerland is still first in the standings.

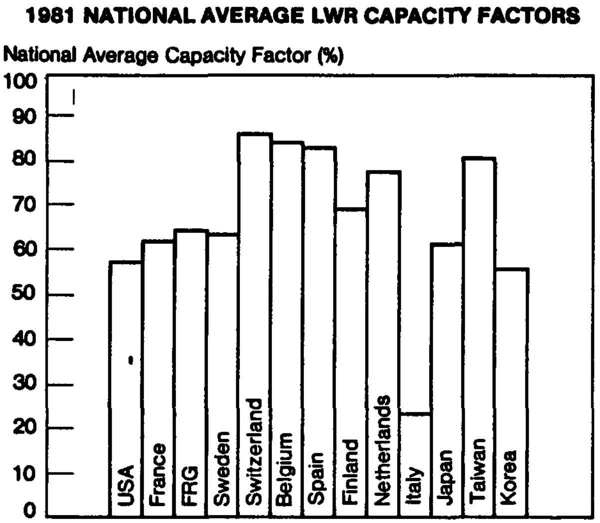


Figure 1

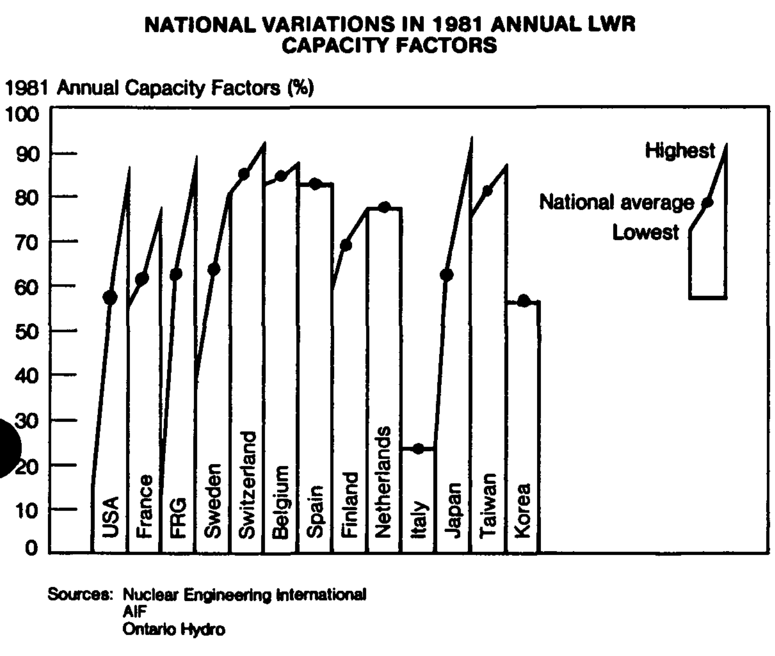


Figure 2

There are of course, conditions that are unique to each country. Thus, we might look at variations within individual countries to see if the record indicates potential for improvement. Figure 2 shows the range in capacity factors among individual nuclear plants in the same countries. In the United States you see a spread from under 20 percent to almost 90 percent, yet these systems are all being operated under similar conditions and utilize similar equipment. If those plants with availability records below the median were all to achieve the present median, the economic benefit would be great. Perhaps more importantly, such achievement would provide an economic premium to the utilities, namely, the increased capacity factor would delay the time they would need to raise the enormous investment for capacity expansion whether for coal, hydro or nuclear plant expansion. For those of us in the nuclear industry, such a delay would be painful in the short term, but the pain would be with us anyway under the present circumstances since the first option for expansion by the utilities would probably not be nuclear. On the other hand, in the long term, the benefit would be real, since the demonstration of superior reliability would be key to reopening the nuclear option.

At EPRI over 95 percent of our nuclear power program is devoted to achieving this objective with programs that are either directly addressing reliability and availability issues, or with programs that are addressing safety and licensing issues which continue to threaten availability. In fact, a significant cause of the lack of improvement in availability over the past three years has been the regulatory impact of Three Mile Island. I do not have the time to go over the specifics of these programs, but each member of the industry knows how to apply its skills to contribute to improved availability. Just as there are many research opportunities for EPRI to so contribute, there are many technical and business opportunities for the industry to do so as well as contractors to EPRI, as contractors directly with the utilities, and through their own internally financed R&D.

I would like to cite just one example, from among many, of a technical development which will clearly improve availability - and which can be applied to plants in operation or under construction. The example is from the BWR Pipe Crack Program, which, with the PWR Steam Generator Program, represents the two most important reliability improvement programs underway at EPRI. The development is an induction heating stress improvement, the equipment for which is shown in Figure 3, which is now being used in a significant number of BWR nuclear plants. It puts into compression the stresses on the

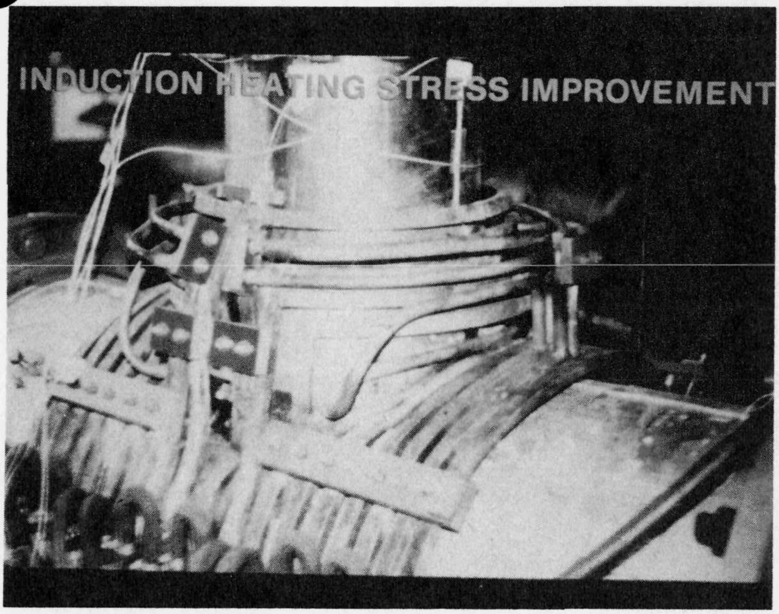


Figure 3

inner surface of the piping, reducing the potential of stress corrosion cracks to propagate. The development was adopted from pioneering work done by the Japanese.

Reducing construction costs and schedules for those plants under construction is a substantially more difficult task than improving operating availability. The reason for this is simple. Change is bad for construction, whether it be a change required by regulation or by the design engineer or by the construction manager. Change disrupts planning, scheduling of materials, and the utilization of personnel. In fact, if nuclear plants today were being constructed without any change, we probably would not list construction costs and schedule as an issue of concern.

The potential opportunity for improvement available to us for the 59 plants under construction is to address the change issue itself. First and foremost, by stopping in so far as is possible, all changes once construction has started, and secondly, for those changes which are still mandatory, that measures be taken to affect change rapidly and efficiently. This means that the ramifications of each change should be identified and clearly specified by the engineer to the construction management. The changes which occur in the field as the result of field interferences unidentified in drawings or models or caused by inadequate engineering layout should be reviewed and disposed of rapidly as soon as the need for such change is identified by the field. Responsiveness in this area cannot be overdone. If it takes highly computerized systems, satellite communications, locating significant engineering forces at the construction site, or all of these things, they should be utilized. The costs of those techniques are trivial compared to the costs of the payroll of the construction work force and the interest collected by the bankers.

Such efforts are underway in the field today and they are achieving results. Figures 4 and 5, taken from EPRI report 1785, "An Analysis of Power Plant Construction Leadtimes," show that the trend of steady increase in average construction lead time of nuclear plants with pre-1972 construction permit issue dates has been supplanted by a declining trend in lead time for the plants with post-1972 construction permit issue dates. The improving trend may be surprising to you, but it seems to be a result of the <u>relative</u> stabilization of regulation after 1972, following the chaos in regulation that occurred after the Calvert Cliffs decision on NEPA. Some plants appear to have succumbed to the TMI-2 regulatory de-stabilization, but on the average the TMI crisis has been weathered better than Calvert Cliffs.

AVERAGE NUCLEAR POWER PLANT CONSTRUCTION LEAD TIMES
Pre-1972 Population

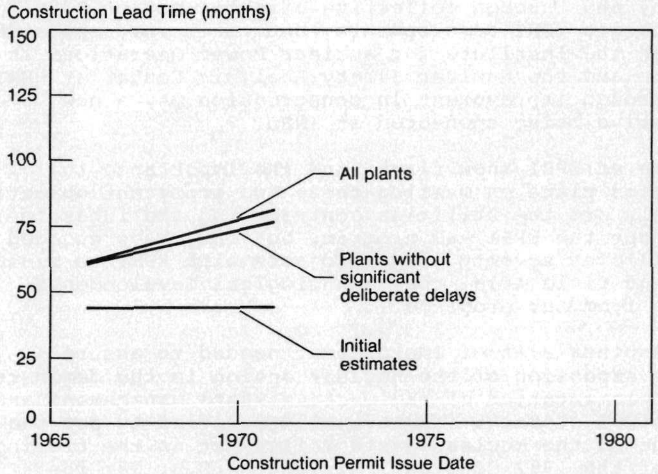
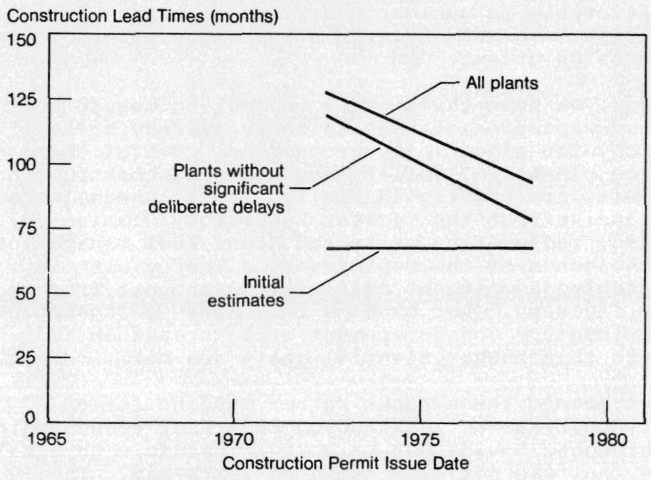


Figure 4

ESTIMATES OF AVERAGE NUCLEAR POWER PLANT CONSTRUCTION LEAD TIMES
Post-1972 Population



Source: U.S. Nuclear Regulatory Commission

Figure 5

I have concentrated on what we in the industry, including those of us at EPRI, can do to assist the utilities in improving the nuclear option. It is of course clear that the utilities can help themselves in both of these areas. They are so doing in each individual company and through collective efforts, not only to incorporate EPRI developments, but to improve operations through the Institute for Nuclear Power Operations in Atlanta and the Nuclear Safety Analysis Center at EPRI, and through improvement in construction QA, a new initiative being sponsored at INPO.

We at EPRI know first hand the importance the utilities place on meeting these two important objectives. Not only are the utilities contributing the funds to carry out the EPRI R&D program, but they have engaged in well over seventy joint projects with EPRI to field test and field trial the technological developments coming from our programs.

Another area of improvement needed to assure future expansion of the nuclear option is the demonstration and implementation of radioactive waste management and spent fuel storage. We were all gratified to see the passage of the Nuclear Waste Policy Act in the closing days of the 1982 Congress, giving the U.S. for the first time a longterm national program for the permanent disposal of commercial nuclear wastes. Implementation of high level radioactive waste storage is now far better assured. Without substantial progress in this area, there is little hope that public opinion will trend favorably to nuclear power and that the utilities will decide to expand nuclear power capacity when need for expansion arises.

Thus, we have three goals to meet to assure the continued expansion of what is today already a vital technology for electricity production. Two of them, improving plant availability and reducing construction time costs, are heavily in the industry's hands, with a needed assist from the Nuclear Regulatory Commission. The third, radioactive waste and spent fuel management, is in the hands of the Department of Energy with an unprecedented commitment of financial support from the utility industry. Let us hope that these partnerships between industry and government will strengthen and mature so that those essential goals are met.

But aren't these tasks rather mundane for an industry that has an outstanding record of technological breakthroughs, having put to world-wide use a physical process that was not even known 50 years ago? The outstanding technical capability that is in the nuclear industry today was attracted by the technical challenge and opportunity for technical achievement. I would suggest that these three tasks are still as technically demanding as the earlier, more glamorous, nuclear power development program. The goals will not, in fact, be achieved without a high level of technical sophistication in their pursuit and the application of the most modern available technological developments in materials, chemistry, and electronics.

As only one example, at EPRI we put great store in the development of non-destructive evaluation techniques, both on and off-line, as a major aid to availability improvement. Miniature linear accelerators, multi-frequency eddy-current sensors, robotic technology for ultra-sonic flaw detection and pipe welding repairs, computer-based adaptive learning techniques for automated prediction of crack propagation characteristics--these are just a few of the titles of the developments that are now in their last stages of field hardening and testing at EPRI's Non-Destructive Evaluation (NDE) Center in Charlotte, North Carolina.

I'd like to summarize briefly just one of these, the first mentioned, the miniature linear accelerator, or MINAC. Figure 6 shows this device being tested at the NDE Center, using a spare main coolant pump casing. You can see the simulation of power plant conditions by the placement of wooden mock-ups to represent the geometric constraints in containment and the clothing of the inspection personnel in anti-C clothing. The personnel shown in the picture are utility and service contractor inspectors who are being trained in the use of the equipment during the field testing. The MINAC has been used to meet the 10 year in-service inspection requirements on the thick-walled stainless steel pump casings in four nuclear plants, a task that was impractical before this device was developed. Rochester Gas and Electric made a major contribution to the development in a joint project with EPRI, developing all the handling gear and perfecting the process in field trials on the GINNA plant. The device has practically paid for itself in just one by-product application. Con Ed asked us to use it to inspect a main steam isolation valve. In 24 hours, with the plant still at power, the inspection showed that the valve was leaking and identified the corrective measure to stop the leak and regain 8MWe of power that was being lost.

But should advanced nuclear power development be dropped to concentrate on these three primary tasks? The tremendous potential of advanced systems - the breeder to open up a many-centuries supply of fuel, the high temperature gas-cooled reactor to apply nuclear power to process heat - and the lengthy time it takes

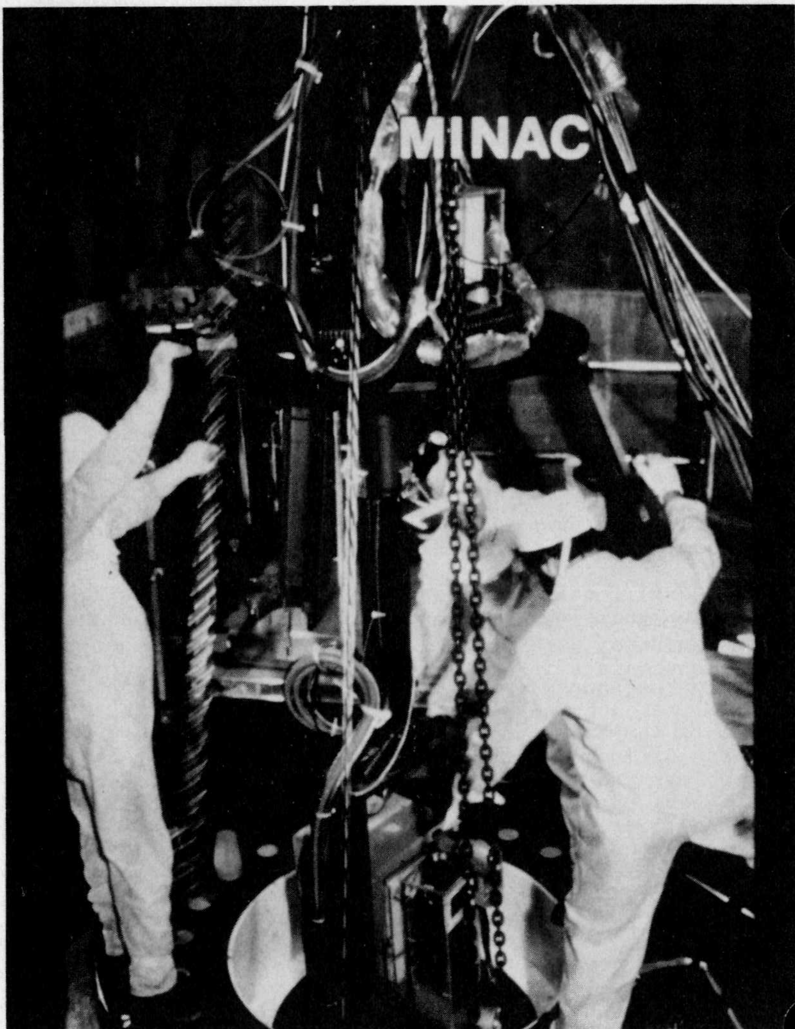


Figure 6

to perfect these developments makes it mandatory that development effort continue on them now. Because of the long term nature of these developments, government must play a leading role at this time in advanced fission nuclear power development, just as it is in fusion power development. Here again the roles of government and industry can be complimentary, not duplicating.

There is another, little-noticed, vital role that advanced nuclear power development is playing. It's technical results are feeding in both directions in the nuclear power technological continuum. For example, more than a decade of technological development, which had been directed to the LMFBR core disruptive accident, has recently been adapted and applied to the LWR degraded core cooling issues arising from Three Mile Island. Tremendous insight has been provided in LWR safeguards equipment evaluation, accident mitigation measures, and containment integrity issues from the LMFBR development. Similarly, LMFBR work in radiation damage of structural materials and in liquid metal heat transfer technology is now being applied in the early steps to master the engineering challenges of fusion power systems.

Why did I agree to talk about re-vitalizing a technology and industry which I see to be so vital in its present accomplishment and future challenge? Perhaps we are adopting words from the lips of the opponents of nuclear power much as they have adopted words from our lips - scram, maximum credible accident - to de-nigrate our efforts. However, we seem to be losers both ways because of our naivete in such word games - and this has not helped us in the idea-battles surrounding nuclear power. Let's go back to our offices and laboratories and renew our efforts to increase the lead in industrial and environmental performance this vital industry already has over the competing electric generating technologies.

THE STATUS OF THE FEDERAL MAGNETIC FUSION PROGRAM or FUSION IN TRANSITION: FROM SCIENCE TO TECHNOLOGY

James S. Kane, Deputy Director
Office of Energy Research
Department of Energy

Despite the fact that I have already listed two titles for my presentation, I'd like to offer a third: "An Outsider Speculates on the Future of Magnetic Fusion." I have never been scientifically involved with the fusion program, but I have been an interested observer since about 1955, when I first joined the Lawrence Livermore National Laboratory, then the Livermore branch of the University of California Radiation Laboratory. At that time project "Sherwood" was one of the Laboratory's most exciting projects, and it is easy to see why -- it involved such notables as Edward Teller, Chet Van Atta, Nick Christofilos, Dick Post, Harold Furth and Stirling Colgate. It was extraordinarily challenging, scientifically.

Twenty-five years later, the very difficult scientific program that they and others started has made remarkable progress. In my talk today I'm not going to spend much time on the details of that progress, but let me summarize, in my words, the current status:

- o Large, sophisticated facilities are built or are under construction for the two principal confinement concepts - tokamaks and mirror machines.

- Scientific feasibility is expected for both these approaches in the 1986-8 time frame.

- There is high confidence that the behavior of the plasma is tractable, and sufficiently understood to permit reactor level operation.

- There is lively interest in confinement configurations other than the "mainlines."

- For about the next five years, the goals of the program are clear and commonly agreed on: to understand the creation and confinement of the plasma and to assure the suitability of the associated technology in the near-reactor regime.

The present status of the program is therefore extremely gratifying for the participants. It has been a very difficult scientific undertaking, and progress has been, to repeat, remarkable.

That is all the time I intend to spend today on past accomplishments, and on the current status of the Federal program. Instead, I'll take the approach of asking the question, what's next? What are the steps that must be taken, assuming that the scientific problems can be solved?

One can make an interesting comparison of fusion, at scientific breakeven, with the first fission reactor at ~ zero power at Stagg Field in 1943. The science of the matter is no longer in question; what's next is application. But in contrast to fission in 1943, there are no defense-related applications for which fusion is uniquely suited. The further development of fusion hinges solely on its ability to provide reliable, economic and environmentally acceptable energy in useful form. The next step is therefore a program designed specifically to increase our confidence that this can indeed be done. During the rest of my talk I will discuss a few of the features that I think such a program must have. To help me organize my thoughts, I have listed several of the more important questions we should ask ourselves in defining the program. I have ordered my list according to increasing difficulty, at least in my opinion.

Who should underwrite the program?

Who should plan and manage it?

Who must be convinced that the risks are properly understood?

What should be the content of the R&D program?

What is the urgency of the program?

Let me discuss -- not answer -- them in turn.

Who should underwrite the program?

For this question, as well as those that follow, I recognize that the content and nature of the risk-reducing program will change with time. If all goes well, and by that I mean if the program succeeds in reaching its objectives, the risks of fusion energy will in time become comparable to those normally assumed by industry, and at that time the private sector will take over.

At present, however, the technical and economic risks are too great, and the time scales are too long to expect much support from the private sector. This fact, coupled with the fundamental importance of energy to our national welfare, implies an initially large government role, but one that with success (or without, for that matter) will decrease with time.

There is no disagreement with the need for government involvement. The fusion program has received strong support from every administration.

Who should manage the program?

Initially, when government funding dominates, the government will insist on a strong management position. Nevertheless, it is clear that the goal of the program is energy production, by the private sector. It is therefore essential that the private sector be deeply involved from the start, with the expectation that its role will increase with time. Those who speak of commercialization of any technology by the government, without the deep involvement of industry, aren't facing reality.

Who must be convinced that the risks are properly understood?

I have made a short list of the participants who I believe must be convinced, in the order that it must be done.

Government officials and managers

Congress and key staff

As long as Federal funding is involved, the above parties will have to be convinced that the program is in the interest of the taxpayers and that it continues to be technically promising, so that government involvement is warranted. At the present time, such conviction exists. Next:

Individual private sector decision makers

Boards of directors and stockholders

Decision makers in financial markets

Those of you who deal with people in these last three categories will appreciate the effort needed before fusion is "commercial" in the sense of normal industrial ventures.

<u>What are the questions to be asked?</u>

By this I mean what is the information that must be obtained to achieve the level of confidence that will be needed -- what is the nature of the R&D program? Of course no one knows the answer; the questions and their priorities will change as knowledge is gained. But I believe that the following four categories of inquiry will be of greatest importance:

Questions related to reliability and availability

Questions related to first cost and overall economics

Questions related to safety and environment

Questions related to the sociology of the construction and operation of complex facilities

Just exactly what the components of the development program should be is an extremely controversial issue, but it has the virtue of being mostly technological. I have no doubt that consensus can be reached on an appropriate list of questions that must be asked and answered if the goal of the fusion energy program is to be attained.

The questions cannot be just those related to commercializing the present approaches, although many of the underlying technologies are generic, and will apply broadly. But we should not ignore the possibility that a revolutionary idea or discovery will change the program dramatically. It will be decades before fusion is commercial, and we can expect science and technology to change as much -- and likely more -- than they have since fusion research was first started. I'm sure the fusion scheme that is ultimately commercialized won't bear much resemblance to today's concepts.

What is the urgency?

You can see why I saved this one until last. It is surely the most contentious question I've posed, mostly because it is difficult to get an answer based on objective reasoning.

The way one would like to answer this question is first to ask how much energy the country will need in the future. Those of us who have seen exponentials extrapolated over many doublings know what a chancy business this is.

But assuming you can estimate demand -- along with cost, because demand independent of cost has no real meaning -- you must now determine the cost of fusion energy and all alternatives as a function of future date. Fusion will start penetrating the market when its cost is attractive, compared with whatever else there is. And of course, if you really believe you can achieve this wonderful level of prediction, you can arrange to have fusion ready for commercialization at precisely the right time.

The obvious problem with this analytical approach is that no one has the slightest faith that the answer it gives will be better than an educated guess. Nevertheless, such an approach keeps us mindful of an important fact: that fusion will be commercialized only when it is economic to do so.

But if we were to try to obtain a plot of fusion energy cost versus time, here are just a few of the factors we'd have to include:

Funding level of the development program.

Pure or hybrid device?

Early or late choice of confinement scheme?

Level of government involvement.

Electricity or fuel producer?

Extent of technical success.

I'm sure all of you could add your own favorites to the list.

The situation with the alternatives is even more difficult. I took only a minute to make up the following list of considerations that must somehow be factored into predictions of future energy costs from alternative sources:

National and international acceptance of fission breeders.

Successful resolution of the nuclear waste issue.

Effect of CO_2 on climate, and effect of local climate changes on economy.

Will the Colorado western slope become Houstonized?

How much SO_2 is acceptable?

How much petroleum is in the continental slope and rise?

Are our petroleum sources safely diversified?

What's solar energy's future cost, including storage?

What's your list?

The diversity of the questions on my list is intended to show you the impossibility of energy futurology, at least with the long extrapolations needed for fusion. The analytical approach just doesn't work. So the fusion program will continue to be funded at a level determined by a process of collective judgment, where each participant assigns his or her own intuitive weighting of the variables such as the state of the economy, fusion's technical promise, progress of competing sources, the quality of the proposed program and perceived urgency. And of course there also must be a recognition that there is a threshold of health for fusion -- below a certain level a meaningful fusion program is impossible.

Well, as you've probably noticed, I've asked a lot of questions, but answered none, which is the way I planned it. I know that my talk has been about 180^{o} from what you expected. Most such talks start with the virtues of fusion, recount the progress of the past year, and predict the technical accomplishments of the next.

In contrast, I've accepted without comment the excellent progress that has been made, I have assumed that scientific breakeven will occur as expected, and have spent most of my time speculating about the very challenging future beyond that time. A large amount of work remains to be done. Yet there is no question that we must continue, and for exactly the same reasons I first heard back in 1955:

Fusion energy is essentially inexhaustible.

Fusion energy appears environmentally acceptable.

Fusion energy is one of a very short list of alternatives.

Although the world has changed in ways beyond prediction since that time, those reasons are as true today as they were then.

INESCO AND COMMERCIAL FUSION POWER IN THE NEXT DECADE

Dr. Robert W. Bussard
International Nuclear Energy Systems Company, Inc.
La Jolla, California

I. COMPANY BACKGROUND AND DEVELOPMENT PROGRAM

In 1976 Dr. Robert W. Bussard, and Professor Bruno Coppi (MIT) conceived the RIGGATRON fusion power core as a means of achieving fusion ignition and controlled fusion power in a practical, compact fusion reactor, and patent applications were filed accordingly. The patents were assigned to INESCO, Inc. (International Nuclear Energy Systems Company, Incorporated, a Maryland Corporation), which was founded in late 1976 for the express purpose of carrying this idea to technical fruition and commercial application. In mid-1977 the U.S. Energy Research and Development Administration (USERDA) awarded INESCO, Inc. a contract to perform technical and economic feasibility studies of this unique approach to the development of fusion power. Results of this study (in mid-1978) showed the enigneering and physics conditions required for technical success and economic feasibility of the concept.

At the conclusion of this study, INESCO obtained private funding (to retain control of future development rights) from Litton Industries, Inc., to evaluate all possible major commercial energy plant applications of RIGGATRON fusion power devices. These studies, conducted over 18 months, showed an astonishing applicability of the RIGGATRON device to a wide variety of energy plant types and functions, with very large return-on-investment and large profit margins for most of the applications. These ranged from low-cost steam production for electric power generation, for heavy oil stimulation and recovery, for other thermal chemical plant processes (including desalination, alcohol production, etc.), to inexpensive neutrons for fusion-driven fission power generation, to fissile fuel production for nuclear reactors, and to nuclear waste "burning" by transmutation.

Upon completion of these Litton-supported studies April of 1980, FDX Associates, L.P. (a Delaware investment limited partnership) was established to provide private funding for initiation of the RIGGATRON unit development program. Under this program INESCO will design, build and test five pre-commercial prototype RIGGATRON fusion power units by the mid-1980's. These units are planned to operate at steady burn power output levels of over 200 Mw_{th} which will demonstrate the engineering and physical practicality of the concept. Success of one or more of the five planned test units will prove the engineering and physics necessary to allow construction, test and manufacturing of prototype commercial units for subsequent energy plant applications; the production of electric power, process steam, and nuclear fuel.

INESCO, Inc. currently employs a staff of 80, 55 of whom are engineers and scientists. The main office is in La Jolla, California; the Materials Development Laboratory is in Del Mar, California. A Washington, D.C. liaison office is maintained in McLean, Virginia.

The INESCO/FDX development program utilizes aerospace enigneering developmental philosophies and proven aerospace structural and thermal energy transfer technologies in its program conduct. The approach follows the manner of turbojet and rocket engine development, by designing to materials limits of the components, testing the integrated system, iterating this development process by subsequent redesign and retesting, and finally by operating below limit levels to assure predictable performance and unit lifetime.

Since 1978, approximately $12 M has been expended in work on the RIGGATRON unit. Over the next five years, it expected that costs of the development program will approximately $125 M (1982 $) for demonstration testing of the five full-scale RIGGATRON fusion power units.

Work conducted to date has led to conceptual design of the first fusion test units, and to the successful development of basic materials and fabrication techniques required to assure performance and engineering integrity of these units. Simultaneously, initial specifications for the test site, electrical power supply, water cooling supply and other auxiliary sub-systems have been defined. Finally, conceptual plant designs have been developed and analyses made of commercial market sales futures, in order to provide guidance to RIGGATRON unit design and development. Results of extensive analyses of the economic prospects, market penetration, and profit potentials from plant applications of RIGGATRON units in various major energy product markets show the potential for rapid commercial deployment, and present-discounted-value estimates in 1986 of future profits to be many tens of billions of (1982) dollars.

II. THE TECHNOLOGY OF RIGGATRON FUSION POWER GENERATION

The tokamak is a concept first invented by the Russians in 1966, which permits the stable and efficient confinement of a hot "plasma" in a toroidal or "doughnut-shaped" magnetic "bottle" The tokamak configuration is the world standard for all major national fusion research programs. The RIGGATRON is a very small high-field tokamak, which employs unique thermal and mechanical designs for appropriate energy extraction.

The hot and densely confined "plasma" gas is composed of ions of the heavy hydrogen isotopes, deuterium (D) and tritium (T) which are "fusing together" to form helium and neutrons. The toroidal magnetic bottle confines and contains the heavy hydrogen fuel and the helium by-product, while it permits the energetic neutrons to escape. The tokamak is a special type of magnetic bottle, and the RIGGATRON is a special type of tokamak. Figure 1 shows a schematic cutaway of the RIGGATRON tokamak device.

This magnetic bottle and the escaping fusion neutrons can be thought of as analogous to an incandescent light bulb emitting light. To make use of the neutrons and extract energy in a usable form from such a device it is necessary to put a neutron-absorbing blanket around the RIGGATRON tokamak, much as an opaque lamp shade placed around a light bulb would absorb the incident light and convert it to heat. In a similar fashion, the blanket absorbs the neutrons which, in turn, heat the blanket material or, in the case of fusion/fission hybrids, may also create fission power from natural uranium or breed fissile nuclear fuels. The blanket is then cooled in a conventional manner to remove the neutron-deposited heat energy. The blanket coolant can then be used to generate steam which can be supplied to process plants or used to drive conventional steam turbine generators.

Figure 2 shows the RIGGATRON Fusion Power Core (FPC unit, sealed in its vacuum "light-bulb" envelope, mounted at the center of a power bay in which the blanket region lines

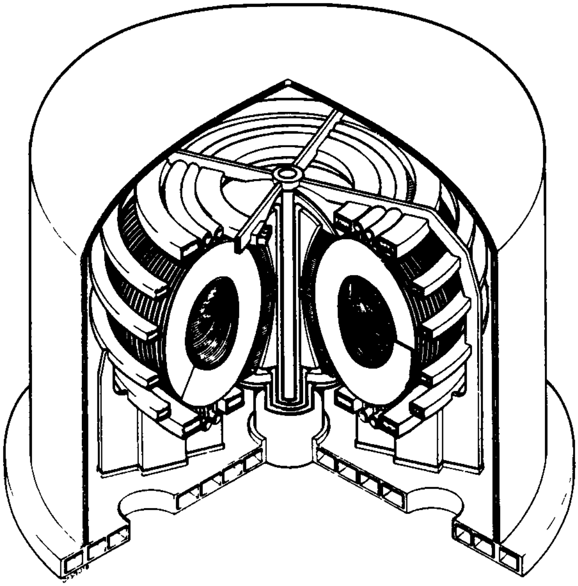


FIGURE 1: RIGGATRON^{TM} FUSION POWER CORE

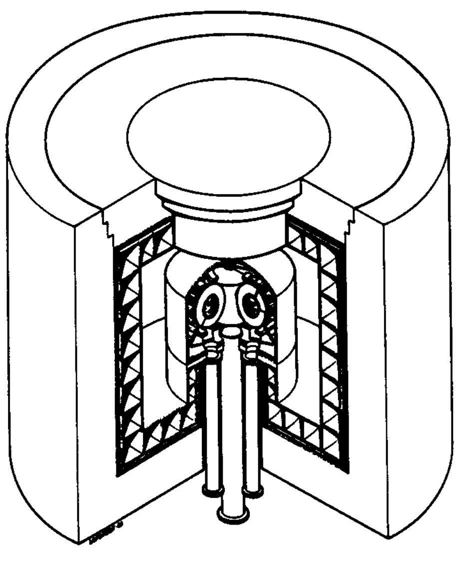


FIGURE 2: FUSION POWER CORE CELL

the walls of the room, away from the FPC. The FPC is at the center of the figure. The central cutaway shows the small quasi-circular magnetic-field-generating coils which act as the magnetic bottle. The "fusion plasma" is contained in the toroidal ring within this "bottle." The neutrons which are generated in this plasma are not contained, but emerge in all directions and are ultimately absorbed in the surrounding blanket. Useable energy is extracted from the blanket by a cooling system. The blanket also contains lithium (Li) which under neutron bombardment produces tritium (T) which, in turn, is subsequently used as fusion fuel to maintain the fusion process with deuterium (D). The shielded power bay room is closed at its top by a removable shield plug or "lid." This can be lifted off and the centrally-located RIGGATRON fusion power core (the "light bulb") can be disconnected, removed and replaced without disturbing the neutron-absorbing blanket and the balance-of-plant hot-water steam-extraction system.

The tokamak is the only known and proven scheme for successful fusion plasma confinement, and is the basis for all current major large-scale government sponsored research on fusion physics. The fundamental engineering innovations which INESCO introduced into fusion reactor design is nothing more or less than the use of water-cooled copper alloy conductors for the coils which produce the toroidal magnetic field, and their use at very high fields to produce a tokamak of very small size. It is this small size of the RIGGATRON machine which permits its low-cost, its short development time, and its potential near-term profitable and practical plant applications over a wide spectrum of power plants and energy products.

In order to produce useful power levels, a small machine must operate at high power density. This results naturally in a short working life, due to a finite limitation of its materials to withstand accumulated neutron radiation damage. Thus, such units must be replaced periodically, in the same fashion as electric light bulbs. Because of this replacement feature, no in-place maintenance is required for the unit; when it reaches end of life or fails, it is simply removed and replaced. Design and cost analysis shows that over its expected lifetime each unit is anticipated to produce useful thermal energy at a very low cost (e.g. cost equivalent to oil at $1-2/bbl). In a plant, its cost is therefore regarded as a direct ("fuel") cost element rather than a capital investment cost. The only economic penalty associated with use of such inexpensive "fuel" is that some fraction of the gross electric output of a RIGGATRON-unit-driven plant will be consumed internally to maintain the confining magnetic fields. This results in a fractional increase in capital plant specific costs; however, the net cost of power (or steam, etc.) is found to be lower than for other competing energy sources.

Arbitrarily large amounts of gross plant power can be obtained from a modular array of single RIGGATRON unit systems. Figure 3 shows a conceptual version of such a multi-unit plant. In any RIGGATRON-driven plant, a high utilization factor can be obtained by providing one or more "extra" blanket/RIGGATRON units in the plant (but no extra thermal/conversion equipment). When one unit is shut down for fusion power core replacement, the "spare" unit is turned on so that there is no plant down-time due to unit failure or replacement. Replacement time can be of the order of one day or less, because the FPC unit is a canned assembly and is easily disconnected, removed, and replaced. This "plug-in" quick-disconnect approach was pioneered and proven in the U.S. national nuclear rocket (Rover) program over 20 years ago.

It should be noted that fusion, although it is a nuclear process, does not involve any high-level radiation hazards or waste disposal problems of the type which are generally associated with the fission process. The radiation hazards associated with the fusion process are different in kind and are approximately 100-1000 times less hazardous than those associated with the fission process. In comparison with fission reactor processes, fusion is generally considered environmentally benign.

If the RIGGATRON tokamak is used as a neutron source to generate fissile fuel in a fertile blanket (i.e., in a "hybrid" system), there is the inherent safety characteristic that no "run-away" or "melt-down" scenario is possible with the fusion core. In addition, in a RIGGATRON-driven hybrid system the hybrid breeding blanket can be designed at large volumes so that it will contain the transmuted nuclear fuel and any fission products in a low-density blanket arrangement which can be cooled by simple free convection heat transfer processes, so that no "melt-down" is possible due to blanket coolant pump failure after shutdown (i.e., there will be no need for pumps after shutdown). A RIGGATRON fusion system thus has an inherent safety aspect which is not possible with most fission reactor systems, or with most large-scale superconducting magnet fusion system concepts.

III. ECONOMIC PROSPECTS

The purpose of the INESCO/FDX fusion development program is to demonstrate the viability of the RIGGATRON fusion power core approach. These units, which are compared to a consumable fuel, can then be manufactured and sold to

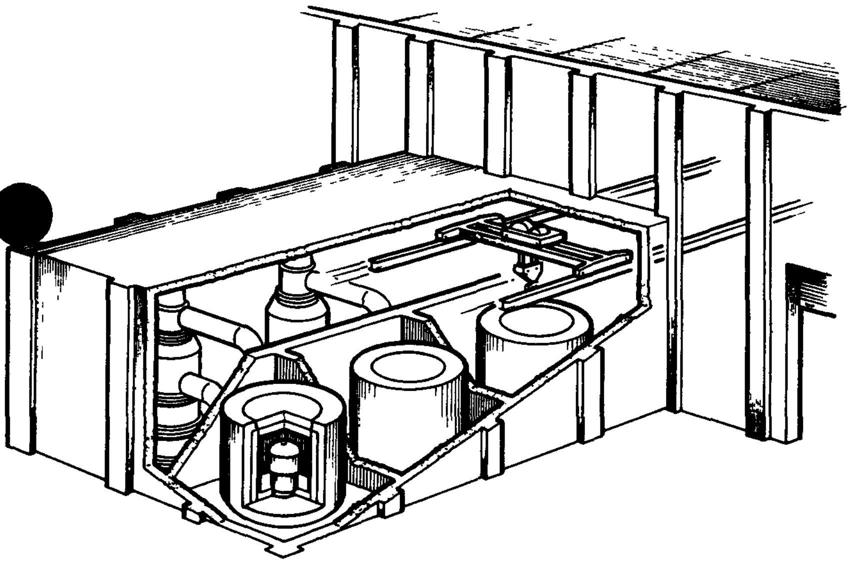


FIGURE 3: FUSION POWER CORE CELL MODULAR ARRAY

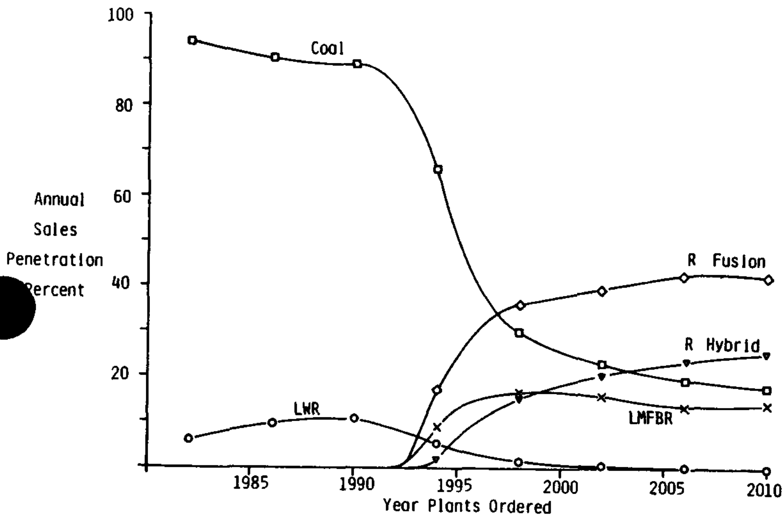


FIGURE 4: MARKET PENETRATION OF FPC PLANTS

drive most of the energy and power plant systems in the world which currently depend on oil, gas, coal, or nuclear fission power for their operation. To ensure rapid commercial deployment, design and development work will be conducted on plants and blankets in parallel with RIGGATRON unit development. At the time of operation of the demonstration RIGGATRON units, it will be possible to move directly to commercial fusion unit design and manufacture and to initial plant design and construction.

The first plants are expected to come on line in the early 1990's and be followed by an increasing number of plants in all market areas in succeeding years. Properly deployed in appropriate plants the RIGGATRON unit can be applied to a large fraction of the world's current energy markets, with the generation of very large profit margins. The quickest plants to build and bring on-line are those for fusion-driven breeding of nuclear fuels, and pure fusion steam and electric power plants by retro-fitting of existing oil-fired plants. Fusion-fission hybrid plants and stand-alone fusion-electric plants will cost more and take somewhat longer. Studies show that such applications offer overall Return On Gross Assets (ROGA) of 30% to 60% per year for all potential applications, at current energy market prices. Return on Investment (ROI) for such plants can easily exceed 100% per year in all plants.

Profit margins were analyzed using data for anticipated capital costs, consumable fuel costs and normal costs for operations and maintenance of each type of energy plant. Data sources for these costs included major U.S. industrial organizations engaged in the design and construction of all types of commercial power and energy plants, as well as plant design studies conducted for the RIGGATRON fusion system. Projections of market size and distribution in each of the markets considered were based on world standard models of future energy markets in the OECD nations, obtained from international and major U.S. industrial sources. Econometrics analyses have been made of the market penetration of RIGGATRON units into all applicable major world markets for nuclear fuels, electric power, and synthetic and other portable liquid fuels. These analyses utilized standard market penetration models developed by major U.S. energy/econometrics organizations, which have been proven reliable over the entire breadth of the energy and heavy industrial products markets.

These analyses were based on the conservative assumptions of a 30-year time period to capture half of the available electric power and liquid fuels markets, and 15 years for nuclear fuel production markets. Historical market penetration half times in new energy displacement markets (i.e. coal vs. wood, oil vs. coal, nuclear vs. oil,

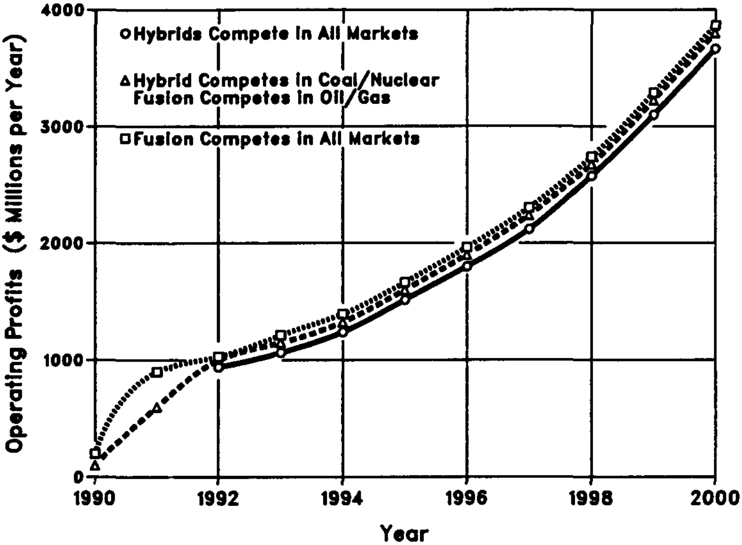


Figure 5: Profit Projections from Riggatron™ use in Plants Producing Electric Power in OECD Countries

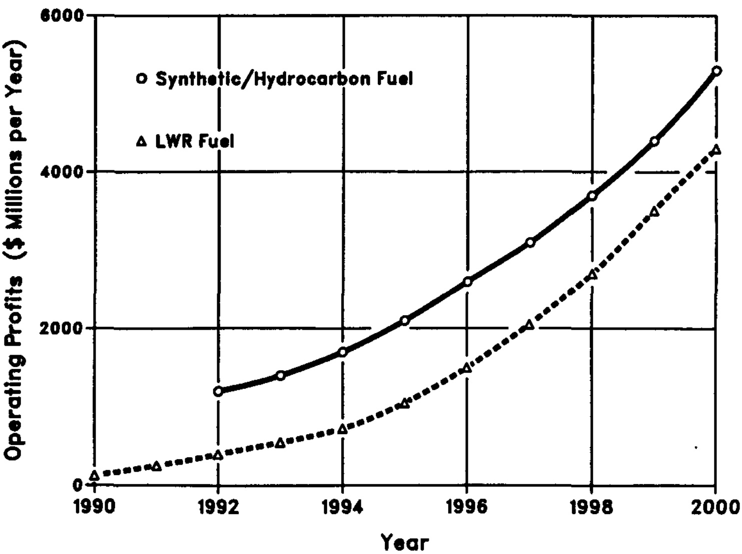


Figure 6: Profit Projections from Riggatron™ use in Plants Producing LWR Fuels and Synthetic/Hydrocarbon Fuels

etc.) are approximately 40 years. In contrast, the market penetration half-time for new product substitution markets (i.e. advanced jet engines vs. old jet engines, etc.) is historically 7-10 years. The 30 year half-time chosen for RIGGATRON unit electric plant deployment is based on the fact that some fraction of such plants will involve substitution (retro-fitting) rather than complete new plant displacement. This choice of penetration half-time for the liquid fuels substitution market allows for new plant construction for alcohol production, while noting that steam-stimulated oil production fits existing refineries. The 15 year half-time chosen for nuclear fuel production is based on simple substitution of RIGGATRON-plant bred fuel for conventional enriched fuel, noting that some new fuel-fabrication facilities must be constructed to complete the market. An example of RIGGATRON plant deployment into the U.S. electric utilities power market is given in Figure 4, which shows the rapid displacement of conventional plants as RIGGATRON units become available.

Figure 5 shows the gross operating profits available from the electric power market for three different models of RIGGATRON plant type deployment. In each case it was assumed that five plants would be operating in 1992. It was further assumed that pure fusion plants operate at a magnetic field confinement efficiency (called "beta") of 25% (this sets the internal electric power consumption requirements), and that hybrids operate with a "beta" of 6%. An interesting feature of the results of these analyses is that the profits available are found to be relatively independent of the mix of types of RIGGATRON plants used to compete in the different segments of the electric power market. The key to profitability rests simply on achieving fusion ignition and controlled burn; the objectives of the INESCO/FDX development program.

Figure 6 shows gross profits available from use of RIGGATRON tokamaks for the production of light water reactor fuel and liquid fuels. These latter include production of fuel grade alcohol and the steam stimulation of heavy oil for petroleum production. The sales profitability shown is based on the high costs of enrichment and enriched uranium product in comparison with the low cost to produce these fuels in a RIGGATRON "fuel factory". The profitability of tokamak use in plants producing liquid chemical fuels is comparable with that for fission fuels, a smaller market, because the sales rate of tokamaks is constrained in the 1990-2000 time period by the limited rate of growth projected for the synthetic fuels production industry.

It is important to note that all econometric computations were performed with constant money values, zero inflation rate, at the level of 1982 dollars.

Industrial Involvement in Fusion Engineering Development

Leonard F C Reichle
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For a technology that has not yet established scientific feasibility, Fusion Energy in the United States has achieved substantial industrial involvement.

Programs for the control of thermonuclear energy for civilian application were established as far back as the early 1950's. Until recently, industrial participation was limited largely to the design and construction of buildings and conventional facilities and to the supply of equipment specified or designed by the fusion laboratories and universities.

Gradually, fusion projects became larger and more complicated. The transition from emphasis on science to emphasis on engineering and industrial know-how began to take place. Companies began to look ahead to the day when fusion devices would become part of commercial electric power generating systems.

The survey described below attempts to quantify the extent to which industrial involvement has been achieved in magnetic confinement fusion. It shows, to the extent that data are made available by nine organizations (industry companies, universities and national laboratories), how many staff and supporting personnel of industry companies have become involved in fusion as a result of such organizations sub-contracting to industrial companies during the last six years, 1977-82.

<u>Ebasco</u>

The Princeton Plasma Physics Laboratory (PPPL), with its own staff of scientists, engineers and laboratory technicians, designed and built many small fusion devices and the relatively sizable Princeton Large Torus (PLT) and the Poloidal Diverter Experiment (PDX). However, in view of the size and complexity of the Tokamak Fusion Test Reactor (TFTR), PPPL decided to engage an Industrial Subcontractor to perform engineering and design, procurement, installation and assembly of the TFTR. Ebasco with Grumman Aerospace as an integral member of its team, was engaged as Industrial Subcontractor.

On the TFTR Project during 1977-82, Ebasco costed approximately $125,600,000 dollars for engineering services, procurement of materials and equipment and installation and assembly. This included design and fabrication of TFTR Toroidal Coils and Poloidal Coils, High Vacuum Valves, Turbomolecular Pumps, Transformers, Rectifiers, Shear Compression Panels and Superstructure, Coil Case Ring Forgings, Coil Case Nitronic 33 Plates, Coil Conductor, Vacuum Vessel, Capacitor Charge and Discharge System, Tritium and Non-Tritium Gas Delivery Systems, Heating and Cooling Piping Systems, Coil Cases, etc. These engineering services employed an average of 131 Ebasco/Grumman people working together in a team relationship. Peak Ebasco/Grumman employment on the project was 525, exclusive of craft labor which peaked at about 420. Even these numbers do not express the full involvement of Ebasco/Grumman. Many scientific, engineering and other technical specialty staff were sent to the project for short-term assignments as their specialty knowledge was needed, and then were sent back to their home departments as their assignments were completed. The statistical average of 131 represents many more than 131 people who have worked on the project. Even at the statistical peak of 525, more than 525 people were involved because, while the peak lasted for several weeks, a number of specialty staff worked on the project on a rotational basis.

Ebasco entered into about 400 subcontracts for materials and for shop design and fabrication of equipment and components. On this subcontracted work, approximately 12,500 scientific, engineering, design, fabrication and other supporting personnel were employed. (See Table 1) This figure of 12,500 does not include the large number of employees of the companies that bid unsuccessfully for the 400 subcontracts.

Princeton Plasma Physics Laboratory

PPPL directly (separate and apart from the major Ebasco Industrial subcontract) entered into 10 subcontracts to supply certain equipment and components for the TFTR. These items included the MG Sets, Computers, NB Power Supplies, Transformers, NB Ion Sources, Limiters, N. V. Switch Tubes, Cryo Piping, NB Vacuum Enclosure, and Breakdown Oscillators. The approximate value of these subcontracts was $54,650,000. About 75 PPPL staff members were engaged in supervising these subcontracts, on which about 465 subcontract personnel were engaged. Again, this number of 465 does not include personnel engaged in the

Table 1
Ebasco
(1977-82)

Identity of Study or Project	Number of Subcontracts	Value ($USA)	Staff	
			E/G	Sub.
Tokamak Fusion Test Reactor (TFTR) Coils, High Vacuum Valves, Turbomolecular Pumps, Transformers, Rectifiers, Shear Compression Panels and Superstructure, Coil Case Ring Forgings, Coil Case Netronic 33 Plates, Coil Conductor, Vacuum Vessel, Capacitor Charge and Discharge System, Tritium and Non-tritium Gas Delivery Systems, Heating and Cooling Water Piping Systems, Coil Cases, etc.	400	$125,600,000[a/]	131 (Average) 525 (peak)	12,500

a/ Ebasco scientific, engineering, procurement, installation, assembly, management and related services bidding process by companies whose proposals were not selected. (See Table 2)

Lawrence Livermore National Laboratory

LLNL is developing the major alternate to the Tokamak system for magnetic confinement of fusion energy, i. e. the magnetic mirror approach. LLNL's major project is the Magnetic Fusion Test Facility (MFTF). Other activities during 1977-82 included the Mirror Test Experiment (TMX), Reactor Studies, Hybrid Studies, and Magnetics. For this work, 27 subcontracts were entered into by LLNL. Their value was about $153,800,000 and they were administered by 150 LLNL staff. These subcontractors employed about 8,262 scientists, engineers, designers, fabricators and other supporting personnel. Seven industry staff members were assigned to LLNL by industrial companies at no cost to LLNL. (See Table 3)

Hitachi

Hitachi Ltd. is the principal industrial organization in Japan involved in the development of fusion energy.

In 1977, Hitachi performed engineering and manufacturing services on the JFT-2 Upgrade, the Heliotron-E, Triam 1, Asperator NP-3, and others which had an approximate value of $17,415,000 and engaged about 200 Hitachi staff.

In 1978, Hitachi performed engineering and manufacturing services on the Tokamaku Body, the Cluster Test Facility (CTF), Heliotron-E, and others which had an approximate value of $174,150,000 and engaged about 220 Hitachi staff.

In 1979, Hitachi performed engineering and manufacturing services on the Control System for JT-60, the NBI Prototype for JT-60, the Large Coil Task (LCT), the Test Module Coil (TMC), Heliotron-E and others which had an approximate value of $17,450,000 and engaged about 240 Hitachi staff.

In 1980, Hitachi performed engineering and manufacturing services on the Poloidal Field and Power Supply of JT-60, and other tasks which had an approximate value of $43,530,000 and engaged about 240 Hitachi staff.

In 1981, Hitachi performed engineering and manufacturing services on the Heating Device and the Generator System of JT-60, the Diagnostic System of JT-60, and other tasks which had an approximate value of $43,625,000 and engaged about 240 Hitachi staff.

In 1982, Hitachi performed engineering and manufacturing services on the Heliotron-E and other assignments which had an approximate value of $3,053,750 and engaged about 220 Hitachi staff.

Table 2
Princeton Plasma Physics Laboratory [1/]
(1977 - 82)

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff	
			PPPL	Subs
MG Sets	1	19,000,000	5	80
Computers	1	3,000,000	10	40
NB Power Supplies	1	23,500,000	15	75
Transformers	1	2,000,000	7	60
NB Ion Source	1	750,000	10	35
Limiters	1	3,700,000	7	35
H.V. Switch Tubes	1	1,000,000	4	25
Cryo Piping	1	300,000	3	40
NB VAcuum Enclosure	1	1,000,000	12	40
Breakdown Oscillators	1	400,000	3	35
	10	$54,650,000	76	465

1/ John R. Clarke, PPPL

TABLE 3

LAWRENCE LIVERMORE NATIONAL LABORATORY [1]

(Fusion Industrial Contracts 1977-82)

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff	
			LLNL Emp.	Sub. C. Emp.
MFTF	20	$150,000,000	89	8,000
TMX	2	1,000,000	44[2]	200
Reactor Studies	1	1,200,000	11[3]	50
Hybrids	3	1,500,000	2	10
Magnetics	1	100,000	4	2
	27	$153,800,000	150	8,262

1] Carl Henning, Head, Mirror Program Office, LLNL.
2] Plus 2 Industry staff members assigned at no cost to LLNL.
3] Plus 5 Industry staff members assigned at no cost to LLNL.

The combined value of the above work performed by Hitachi during 1977-82 is $286,196,250 and was performed by Hitachi staff ranging from 200-240 people. The value of work subcontracted by Hitachi and the number of subcontract employees engaged in such work are not available. (See Table 4)

General Atomic

General Atomic has been engaged in the Doublet III, OHTE and their Large Superconducting Coil Program. More than 75% of the $31,000,000 associated with the engineering and construction of the original Doublet III was subcontracted to others. About 252 subcontracts were entered into, totaling $19,502,000, ranging from multi-million dollar contracts to Convair for coils and to Fansteel for the vacuum vessel to a few hundred dollars for miscellaneous funds. The number of subcontract employees engaged in the $19,500,000 of work subcontracted is not available. About 200 General Atomic staff members were engaged in the $11,500,000 worth of services and other work performed directly by General Atomic to carry-out its function of designer, System Integrator and Assembler.

The Doublet III Upgrade, providing Neutral Beams and additional Diagnostic Equipment, etc. is expected to cost about $69,000,000 of which General Atomic expects to perform about $19,000,000 of work itself and to subcontract about $42,000,000. The number of subcontracts and subcontract employees is not available. (See Table 5)

Oak Ridge National Laboratory

ORNL is engaged in the development of a broad spectrum of fusion technology. During 1977-82, ORNL entered into 88 subcontracts for Magnetics & Superconductivity, Plasma Heating, Impurity Studies, Fusion Engineering Design, EBT-P, EBT-S, Microwave Development, Materials Program, and Engineering. The combined value of these contracts was $78,750,000. About 158 ORNL Carbide Nuclear Division employees were engaged in subcontract work, and subcontractors assigned 74 on-site personnel to work with ORNL. The total number of subcontract employees engaged in the various offices and fabricating facilities of subcontractors is not available (See Table 6)

General Dynamics

General Dynamics' participation in fusion energy has been largely in the design and fabrication of coils. In the period 1977-82, about 131 of their employees were engaged in the Large Coil Program (LCP), Elmo Bumpy Torus (EBT), Mirror Fusion Test Facility (MFTF), and the Mirror Advanced Reactor Study (MARS). General Dynamics entered into 24 subcontracts valued at about $18,685,000 on which approximately 90 subcontract employees were engaged. (See Table 7)

TABLE 4

HITACHI

(Fusion Industrial Contracts 1977-82)

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff HIT. Emp.	Staff Sub. C. Emp.
1977-JFT-2 UP Grade, HELIOTRON-E, TRIAM-1, ASPERATOR NP-3, and Others	-	$17,415,000	200	-
1978-JT-60, Tokamaku Body, C T F (Cluster Test Facility), HELIOTRON-E, and Others	-	174,150,000	220	-
1979-JT-60, Control System, JT-60, NBI Prototype, L C T (Large Coil Task), T M C (Test Module Coil), HELIOTRON-E, and Others	-	30,537,500	240	-
1980-JT-60, Poloidal Field Power Supply, and Others	-	17,415,000	240	-
1981-JT-60, Heating Device and Generator System, JT-60 Diagonostic System, and Others	-	43,625,000	240	-
1982-HELIOTRON-E, and Others	-	3,053,750	220	-
		$286,196,250		

TABLE 5

GENERAL ATOMIC

(Fusion Industrial Contracts 1977-82)

Identity of Study Or Project	Number of Subcontracts	Value ($ USA)	Staff: GA Employee	Staff: Sub.Cont. Employee
Doublet III (Original Project)	252	$ 19,500,000		
Coils, Structures, Limiters, Vacuum Vessel, Vacuum	GA	11,500,000	200[1]	--
Pumping, Water Cooling System, Buswork, Control System, Power Supply, Machine Assembly, etc.				
		$ 31,000,000		
Doublet III Upgrade				
Neutral Beams, etc.	--	42,000,000	--	--
	GA	19,000,000	200[1]	--
		$ 69,000,000		

[1] Dr. Sibley C. Burnett, GA Director, Fusion & F-M Technology Division

TABLE 6

Oak Ridge National Laboratory[1]

(Fusion Industrial Contracts 1977-82)

Identity of Study Or Project	Number of Subcontracts	Value ($ USA)	Staff UCC Employee	Staff Off-Site Subs.
Magnetics & Superconductivity	25	$ 37,500,000	17	7
Plasma Heating	4	570,000	19	4
Impurity Studies	11	770,000	28	1
Fusion Engineering Design	19	6,500,000	2	31
EBT-P	2	15,750,000	5	18
EBT-S	15	2,200,000	21	3
Microwave Development	5	14,800,000	2	--
Materials Program	2	360,000	29	--
Engineering	5	800,000	35	10
	88	$ 78,750,000	158	74

[1] V.C. Kruzic, Head, ORNL Management Services Section on assignment of Dr. Murray Rosenthal, ORNL Associate Director for Advanced Energy Systems

TABLE 7

GENERAL DYNAMICS [1]

(Fusion Industrial Contracts 1977-82)

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff GD Emp.	Staff Subcontract Emp.
Large Coil Program (LCP)	9	1,301,000	54	23
Elnio Bumpty Torus (EBT)	4	300,000	15	7
Mirror Fusion Test Facility (MFTF)	7	17,019,000	60	54
Mirror Advanced Reactor Study (MARS)	4	65,000	2	6
	24	$18,685,000	131	90

1] Dr. R.F. Beuligmann, GD Program Director - Energy Systems

McDonnell Douglas Astronautics

In the period 1977-82, McDonnell Douglas Astronautics has been engaged in various fusion studies, analyses, R&D tasks, fabrication of components, EBT-P, etc. for DOE, ORNL, PPPL, EPRI, universities and others. About 196 of their own employees have been involved. They have entered into 10 subcontracts involving about 125 employees. The total value of McDonnell Douglas work assignments in fusion energy is $99,189,500, but this includes $93,000,000 for the EBT-P contract which appears to have an uncertain future. (See Table 8)

Argonne National Laboratory

Argonne National Laboratory has been involved in reactor design studies, i. e. STARFIRE, the DEMO Tokamak Study, Blanket Comparison and Selection, and the First Wall/Blanket/Shield Engineering Technology Program. For this work, approximately 9 subcontracts were entered into, with a total value of $4,700,000.

Summary

In all, among only the nine organizations surveyed (Ebasco, PPPL, LLNL, Hitachi, GA, ORNL, GD, McDonnell Douglas, and ANL), the data regarding subcontracting of fusion energy assignments shows:

Studies and Projects	Many different types, ranging from scientific studies and analyses to systems and design engineering, manufacturing or fabrication of equipment and components, installation and assembly, and quality assurance.
Number of Subcontracts	820. One company did not supply data relating to number of subcontracts and another replied only with respect to its Original Project and not its Upgrade.
Value. ($USA)	$890,571,500. This represents only the value of work subcontracted, not the value of fusion energy work performed by the prime organization, which is much more.
Organization Staff	1,430. This represents only the average number of subcontractor employees working on fusion energy work, not the peak number which is much higher (525 rather than 131 in the case of Ebasco's work on TFTR).

TABLE 8

MC DONNELL DOUGLAS ASTRONAUTICS [1]

(Fusion Industrial Contracts 1977-82)

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff	
			MacD Emp.	Subcontract Emp.
Studies, Analyses, R&D Tasks, Fabrication of Components, EBT-P, etc. for DOE, ORNL, PPPL, EPRI, universities, and others	10	$99,189,500 [2]	196	125

1] Dr. Allen T. Mense, MacDonnell Douglass Sr. Scientist

2] Includes EBT-P contract for $93,000,000

TABLE 9

ARGONNE NATIONAL LABORATORY [1]

(Fusion Industrial Subcontracts 1977-82)

Identity of Study or Project	Approx. Number of Subcontracts	Approx. Value ($ USA)	Staff
Reactor Design Studies STARFIRE DEMO Tokamak Study Blanket Comparison and Selection	5	$1,700,000	-
First Wall/Blanket/Shield Engineering Technology Program	4	3,000,000	-
	9	$4,700,000	-

1] Dr. Charles C. Baker, ANL Director, Fusion Power Program

TABLE 10

SUMMARY

Identity of Study or Project	Number of Subcontracts	Value ($ USA)	Staff: Prime	Staff: Sub Employees
All Studies and Projects	820	$890,571,550	1430	21,516

Subcontract Employees	21,516. Two companies and one Laboratory did not supply data relating to number of subcontract employees. Moreover, the number 21,516 does not include employees of unsuccessful subcontract bidders or the short-term employees who collectively are not properly reflected in average numbers.

The conclusion from the above limited data is that a very substantial industrial involvement in fusion engineering development has been achieved. The data do not include fusion engineering development work by subcontractors of the Los Alamos National Laboratory, MIT, Westinghouse, GE, Mathematical Sciences Inc., Boeing, the Joint European Torus Consortium and others. The addition of these and other organizations not contacted for this brief survey undoubtedly indicate that industrial involvement in fusion engineering development is even more impressive.

Part V

TECHNOLOGIES FOR RENEWABLE RESOURCES

Fossil and nuclear fuels, presently our largest energy sources, are finite. Each year we can expect an increasing use of renewable resources to partially displace these finite resources. Considerable research is being undertaken for developing technologies to utilize solar derived renewable resources and, with the improvements in technologies and the increasing real cost of conventional energy, more cost effective applications are entering the marketplace each year.

Renewable energy resources are those that are derived from solar energy directly or indirectly. Primary renewable energy sources include direct passive and active solar heating and cooling, solar industrial process heat, central station electric power generation, photovoltaic conversion to electricity, hydro-power, wind, wood, other bio-mass and organic waste.

This section examines recent advances in the development and economic use of these sources.

RENEWABLE SOURCES OF ENERGY IN THE UNITED KINGDOM

J A Catterall

Department of Energy
United Kingdom

BACKGROUND

The UK is fortunate in having large resources of coal, oil, and natural gas, and active programmes in the application and development of nuclear power, and in the conservation of energy. This situation colours the UK position on renewables, but their importance in meeting special requirements or as an insurance policy is accepted.

As with many other countries, it was not until after the oil crisis of 1973 that a Research and Development Programme commenced. The basic aim of the programme was, and continues to be, to produce by the middle of the present decade, sufficient information on renewables to evaluate their costs and the size of the potential resource, and hence their potential contribution to UK energy supplies.

THE SIZE OF THE RESOURCE

Table 1 shows the estimated size of the useable resources per year in the United Kingdom. It is clear that several of the renewables could in principle make a very significant contribution. But a closer examination

Table 1

Estimated size of usable resource per year

	MTCE
Biomass	35
Geothermal	
a) Aquifer	5-7
b) Hot dry rock	320-9,000
Hydro (small-scale)	0.2-0.4
Solar	66-81
Tidal	20
Wave	50
Wind	95

(MTCE - million tons of coal equivalent)

Table 2
Assumed Energy Prices to Consumer in p/therm at 1981 money values

(The three figures are for the high, medium and low price increase projections)

	1981	2000			2025		
Domestic							
Coal	26	68	50	38	107	85	53
Gas Oil	43	113	91	58	155	130	90
Gas	25	99	82	62	147	124	90
Unrestricted Electricity	133	238	238	142	255	255	154
Restricted Electricity	66	138	138	88	155	155	108
Industry							
Coal	15	50	33	25	73	57	40
Fuel Oil	25	76	61	38	107	89	53
Gas Oil	38	102	83	50	141	118	78
Gas	25	102	83	51	141	118	79
Electricity (average)	66	138	138	88	155	155	108
Gasoline (p/gallon)	54	140	116	107	193	163	158

Table 3
Summary Categorisation of Renewable Energy Technologies

	A	B	C	D
Heat Producers		Passive Solar Space Heating Geothermal Aquifers	Solar Water Heating Geothermal (2) Hot Dry Rocks	Active Solar Space Heating
Electricity Producers	Onshore Wind Tidal	Small Scale (1) Hydro	Offshore Wind Small Scale Wind (3)	Wave
Fuel Producers		Biofuels – Combustion Anaerobic Digestion of animal wastes	Biofuels – Anaerobic Digestion of vegetable wastes – Thermal processing	

of the relative economics, and the restrictions on land use and the environment indicate that they are unlikely to provide a significant proportion by the year 2000. Their total contribution at that time is difficult to evaluate precisely, but is unlikely to exceed two per cent of our total energy requirements. The actual figure will depend critically on the cost and availability of coal, nuclear, oil, and gas, and it may well turn out to be even less than this.

Up until 1982 work proceeded on a broad front to consider all possible options. But for purposes of priority, we have recently made an assessment of the economic prospects of each renewable energy technology, resulting in a set of cost/benefit analyses as a function of various views of the future up to the year 2025.

THE ASSESSMENT

A wide range of energy sources has been investigated in the Department's R & D programme on renewables; each has different outputs and characteristics, and each aims to provide energy to a range of diverse markets. These include space and water heating and process heating, electricity for both central and dedicated supplies, and gas and liquid fuels suitable for different applications. Any technology which is to be successfully exploited must compete economically within its appropriate market. Some of the renewable energy sources can do this now, but others require further development and their prospects must be viewed against future energy prices.

Our assessment was based on this approach and sought to apply the yardstick of cost effectiveness wherever that was possible. The characteristics of each technology determined its appropriate market. Because the value of a renewable energy technology is set largely by the corresponding saving it makes in conventional fuel, it was necessary to make assumptions about future movements in fuel prices. The prices were based on three assumed cases, a high, medium or low growth in energy costs. Since we cannot know how fuel prices will develop, the ranges chosen were relatively broad, and are shown in Table 2. The higher the assumed price of conventional energy, of course, the more favourable becomes the case for renewabl energy technologies.

Although the various technologies in our programmes are at different stages of development, the assessment allowed their grouping into four broad categories, shown in Table 3. Category A includes technologies which are economically attractive now or in the near future, and for which a route to their exploitation, without too serious difficulty, can be envisaged. Category B is also economically attractive but there may be factors militating against market uptake. Category C is generally further away from the deployment stage. They might be less cost effective than competing renewable energy technologies, or they might only be cost effective at a future date. Category D may be cost effective only under the most favourable circumstances (ie with very high costs of conventional energy) and in the very long term. In some cases (1) little further R & D is required, in others much more on the technology (2) or on the market features (3) before an adequate assessment of the potential is possible. As a consequence of the assessment, our R & D programmes have been re-scheduled to concentrate on the most promising. The situation is now as follows.

1 GEOTHERMAL HOT DRY ROCK

The exploitable Hot Dry Rock (HDR) resource in the UK could be used to generate about 2,500 TWh of electricity, representing about 10% of present electricity consumption. Costs are very speculative but the likely cost of generating electricity is presently estimated as 4.0-5.2 p/kWh. At the lower end of the range this might be economically acceptable, since HDR would be a firm source of power requiring no other installed capacity as backup. Combined heat and power HDR schemes could offer substantial improvements in both the efficient use of geothermal heat and in overall economics, but as yet have not been evaluated. HDR is not strictly a renewable technology over normal timescales, since the heat extracted is only slowly replaced from surrounding rock, but it may be possible to extend spent wells at low marginal cost to exploit heat at greater depth. HDR technology is, however, still at the investigatory stage: further work is needed on:

- creating suitable rock fracture zones at depth, and establishing system lifetime;
- HDR generation plant optimisation studies;
- assessment of the possible advantages of CHP-HDR schemes;
- assessment of any general environmental constraints on exploitation of the HDR resource.

The rock fracturing experiments at Camborne are proceeding well. The present programme is centred on a major experiment at 2km depth, where temperatures are about 80°C. On successful completion of that study, the next phase of the work would require a further large experiment at considerably greater depth, say 6km, to reach rocks at higher temperatures (200°C), approaching those which might be used in a full scale application.

2 GEOTHERMAL AQUIFERS

Deep aquifers constitute a potential resource of some 1-3 mtce/year of low grade heat at 60-70°C which might be used for various space heating and industrial purposes, and which is already being used in other countries. Exploitation is dependent on a coincidence of source and suitable heat loads, as well as on cost effectiveness, and the above estimate allows for these constraints. Singlet borehole systems for supplying heat to new commercial buildings on an appropriate scale appear to be generally economically attractive now, but obviously are limited to coastal sites. The need to retrofit special heat emission systems matched to the supply temperatures into existing buildings, or the need for a second borehole to reinject the extracted water into the aquifer would increase costs. The size of the capital investment required for an aquifer heating scheme and the financial return on it, together with the risk of drilling unproductive wells, will determine the type of organisations which may consider using this resource; they are likely to be large rather than small.

The research programme has indicated the areas in the UK where suitable supply aquifers might be expected to be found and the probable depth, temperature and quality of the water or brine. The Southampton project, a development in association with the City Council, is designed to demonstrate the exploitability of the aquifer in the South of England and to test and resolve the various issues of both a technical and an institutional nature, which constrain the exploitation. The drilling of further aquifers is planned.

3 WIND ENERGY

Onshore wind power offers a useful resource, which might contribute up to 20% of our present electricity consumption, allowing for some but not all economic and environmental constraints. The cost of electricity generated from the wind is sensitive to a number of factors, but present estimates of cost, including transmission, are in the range 1.9-4.3 p/kWh, which is low enough to make the use of onshore wind power economically attractive on the assumptions about future fuel prices. Further R & D is needed on:

- optimising wind turbine (aerogenerator) designs, eg exploring advantages of vertical axis machines and incorporating compliant design (as distinct from rigid design) concepts;

- more detailed characterisation of the resources;

- integration of aerogenerators into the national grid.

Environmental acceptability of onshore machines is a serious uncertainty in moving to widespread commercial exploitation. A further difficulty, of course, is that wind is not a firm source of power.

A major part of our programme involves the construction and operation of a 3 MW horizontal axis machine suitable for high wind speeds, and it is located on the island of Orkney. If this is successful, further machines are envisaged supplying power to the national network.

Offshore wind power offers a very large resource (about 140 TWh/year) which might contribute more than half the present UK requirement for electricity from machines located in offshore shallows. Its attractiveness is enhanced by the expectation that environmental factors will prove to be less of a constraint on exploitation than for the onshore resource. Although the cost would be higher than for onshore (the current estimate is 3.1-7.0 p/kWh), at the lower end of this cost range offshore wind power is more economically attractive than some other renewable energy technologies which produce electricity. Much of the generic development of aerogenerator designs onshore will be directly applicable to offshore designs but R & D specifically related to offshore applications is required:

- to clarify the wind and sea conditions to be withstood offshore and the design parameters for machines;

- to develop machine and support structure designs for marine environments;

- to delineate the exploitable offshore resource.

Small wind turbines of 10-100 kW output in principle might find a range of applications in domestic, commercial and institutional buildings, in agriculture, industrial processes and isolated locations. The theoretical potential resource could be some 25 TWh/year (about one tenth of present electricity consumption). The resource, costs and possible cost effective contribution have yet to be adequately assessed, but machines are already available to meet this market.

We also have a programme on the next generation of machines having a vertical axis of rotation, and we are constructing a machine of 25 m diameter generating 200 kW.

4 WAVE ENERGY

Geographically the UK is well situated to take advantage of techniques which could exploit wave energy. The total potential contribution (without incurring punitive transmission costs by going far offshore) is estimated to be about 66 TWh/year, about 25% of present electricity consumption. Early work on model devices led to reference designs which could be used as a basis for cost estimates. Present estimates of the cost of electricity for a large-scale scheme ($\sim$2GW) are in the range 4-12 p/kWh. At the lower end of this range, wave power would be economically acceptable in scenarios which favour the exploitation of renewable energy, but other sources (tidal, onshore wind, hot dry rock) are consistently more attractive economically when analysed under the same circumstances.

5 SOLAR HEATING

The average annual solar energy input in the UK is many times our energy requirement but only the simpler methods of collecting and using solar heat are likely to be cost effective in the UK.

Some passive solar heating measures which can be incorporated in building design, eg the orientation of houses and the size and distribution of the windows used, can give a 10-15% reduction in the annual heat demand and are cost effective now. Most others will probably be cost effective by 2000 as fuel prices rise. However, passive solar heating features are difficult and sometimes impossible to retrofit, and the energy savings attainable will be constrained by rates of building construction. Allowing for the estimated rate of market penetration, the contribution of passive measures to national energy supply might be about 3 mtce/year by 2025.

Active solar heating systems, using collectors and distributing hot water or hot air, can be retrofitted to existing buildings, but at present their costs are comparatively high. Solar water heating systems have an established market now, but will become cost effective for widespread application only if today's costs are at least halved or performance correspondingly improved. The cost reduction required might be obtained by a combination of R & D directed to system optimisation and high volume production and installation. However, allowing for the estimated rate of market penetration, the contribution in the UK is unlikely to exceed 0.5 mtce/year by 2000 but might rise to 4 mtce/year by 2025. Active solar space heating, on current views, appears unlikely to be cost effective nationally, compared with other developments in space heating, such as heat pumps. More advanced systems, for example using stored solar heat in combination with heat pumps, may offer lower costs, and thereby improve the overall cost effectiveness.

6 BIOFUELS

The total potential of organic wastes and energy crops to provide useful fuels in the UK is estimated as about 30 mtce/year. The possible use of various components of this wide range of materials is at different stages of development.

Combustion of biofuel materials represents a significant potential energy resource: collected refuse could yield up to 12-14 mtce/year and other solid materials up to 5 mtce/year. Most forms of collected refuse fuels are cost effective now in national terms, and even at the high end of the supply cost range could, by 1990, achieve a three year payback. Most of the other solid materials which can be used as fuel are also economic now, and all promise to achieve cost effectiveness by 2000. There are however still important technical and environmental issues to be resolved in connection with the use of these materials, and full scale commercial demonstrations of the use of such wastes are now being supported.

Anaerobic digestion of animal wastes could provide up to 3 mtce/year of fuel gases suitable chiefly for use on farms where the resource arises. Use of about 1 mtce/year of this might be cost effective now, or in the near future. Further R & D is required on some technical problems, as the performance of digesters and, in some cases, their use with mixed feedstocks has to be confirmed and demonstrated, but the technology is starting to enter the deployment stage.

7 TIDAL ENERGY

A study has been made of the feasibility of harnessing tidal power in the UK, and a detailed assessment has been made on one site, the Severn Estuary in South West England, where the tidal range is very large (13m). A design of a barrage has been suggested which could generate 13 TWh of electricity per year at a cost of about 3.1 p/kWh. But the capital cost of the scheme would be very large, £5.6 billion, and a decision on further work has yet to be taken.

8 SMALL SCALE HYDRO-POWER

The use of small machines of 25-50 kW output could give access to hydro-electric sources not yet exploited in the UK with a potential to generate 1.8 TWh/year. The cost effectiveness of such machines is very site specific, but several novel machines are being developed with a view to extending the range of water sources which might be used, particularly those with a low head.

MARKET POTENTIAL

The markets for renewable energy technologies in the UK are summarised in Table 4, and the estimated rate of take-up of these technologies is discussed in the preceeding paragraphs. The important features are:

i) the rate of introduction of all renewables is critically dependent on the pace at which fossil fuel prices rise - the faster they go up in real terms the more rapid will be the adoption of renewables;

ii) the development of heat-producing renewables, some of which are already economic (eg refuse-derived fuel, geothermal aquifers and passive solar) may be less sensitive to energy prices and more dependent on institutional factors; and

iii) while dependent on fuel prices the introduction of electricity-generating renewables will also be closely controlled by the rate of increase in electricity demand and the scale of any nuclear power programme.

The fact that the pace of development of renewables depends on such a complex set of interactions means that the scale of introduction by any given date covers a wide range of possibilities. For example:

i) geothermal aquifers - the total UK exploitable resource could be over 1.5 mtce pa which could be served by over 300 wells. At the maximum rate of development this might involve 8 drilling rigs operating continually at around the turn of the century - hardly a big market;

ii) wind - here the market could be large as the highest projections call for over 10 GW of installed capacity (onshore and offshore) by 2025. The limit to development is the industrial production capacity (assumed to be $\sim$ 0.5 GW, ie installing nearly 200 large windmills a year). At the other extreme, low load growth and low fuel prices lead to projections of virtually no wind power development. Clearly the potential market is large, but so too are the risks;

Table 4

The Markets for Renewable Energy Technologies

Renewable Technology	Markets	Other Markets
Wind	Central electricity generation	Electricity generation for remote locations (islands etc)
Wave	Central electricity generation	Electricity generation for remote locations (islands etc)
Tidal	Central electricity generation	
Small Scale Hydro	Local electricity generation	
Geothermal Hot Dry Rocks	Central electricity generation	Steam raising in industry/local CHP
Geothermal Aquifers	Group heating	Low grade heat in industry, horticulture
Solar:		
– Active Space Heating	Domestic housing Group heating	Commercial and institutional buildings
– Passive Space Heating	Domestic housing	Commercial and institutional buildings
– Water Heating	Domestic housing	Commercial and institutional buildings (and specialised, eg swimming pools)
Biofuels:		
– Solid	Industry and Non-Domestic buildings; Group heating	Domestic heating
– Liquid	Transport; Chemical feedstocks	
– Gas	SNG supplement; Medium BTU gas for local industrial use	Electricity generation for remote locations

iii) biofuels - here the economic prospects are most clear cut and biofuels (notably refuse derived fuel plus industrial and agricultural waste) are expected to make the major contribution to renewable energy supplies by the year 2000 (up to 10 mtce/pa), but manufacturing industry will have to design its equipment to meet the needs of the many different industries producing exploitable wastes. This means that initially the market will be fragmented.

INNOVATIVE GAS ENERGY SYSTEMS FOR USE WITH PASSIVE SOLAR RESIDENCES

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Energy and Environment Division
Booz, Allen & Hamilton Inc.
and
Douglas Kosar
Gas Research Institute

Passive solar heating and cooling has become increasingly popular. The Department of Energy (DOE) and the National Association of Home Builders have estimated that five to ten percent of new homes built by 1985 could incorporate this option. Passive solar techniques can reduce heating loads significantly, and also offer an opportunity to lower cooling loads in some regions.

The gas industry has been concerned with this trend. Currently, gas heat is used in about 40 percent of new single-family housing. Its market share dropped during the 1970s, but has stabilized in recent years. Gas prices are expected to be deregulated in the near future, however, making electric heat more economical relative to gas heat, especially in passive solar homes with their reduced heating requirements. Electric utilities are working to take advantage of this opportunity to become the backup heating option of choice in new passive solar homes. They are interested in passive solar's ability to help level winter heating loads, and they are developing and promoting new electric heating systems which work well with passive solar.

In order to maintain or increase its market share in the face of these competitive obstacles, the gas industry must develop and promote its own economical and commercially feasible technologies which can be used in new passive solar homes. To help develop its strategy, the Gas Research Institute (GRI) asked Booz, Allen & Hamilton Inc. to analyze the issues involved in integrating passive solar with gas-fired energy systems, and to recommend specific hardware development and research activities. This paper summarizes some of the study's findings, which are of interest to a wide audience.

OVERVIEW OF PASSIVE SOLAR TECHNOLOGIES

The first task was to develop an understanding of different passive solar technologies, which in turn affect backup system design. Our study addressed ten heating and five cooling techniques. All of the heating techniques use daytime solar radiation as their heat source; they vary by location of collection and storage areas relative to the living space.

o Direct gain systems allow the sun to enter the living area through south-facing glass. Heat is stored in extra floor or wall mass.

o Trombe wall systems position thermal mass behind vertical south-facing glass. Heat re-radiates from the thermal mass wall into the living space, or enters by natural or forced convection.

o Sunspaces or greenhouses store solar heat gain in walls or floors, and transfer excess heat to adjacent living space by natural or forced convection, or sometimes radiation.

o Thermosiphon systems are similar to active solar heating systems except that the working fluid -- air --flows between the collection area and the remote thermal storage area without mechanical assistance. Heat is transferred from the storage mass to the living area using natural convection or fan assistance.

o Thermal storage roof systems use storage elements, such as black water-filled bags, that are exposed to the winter sun and covered by moveable insulation at night. Heat radiates from the uninsulated underside of the roof to the living space below.

Passive cooling techniques are distinguished by the method of reducing heat gain or of discharging excess heat away from the living space.

o Solar load control uses external window, wall, and roof shading devices or reflective window glazings to reduce solar heat gains.

o Natural or forced ventilation techniques introduce cooler outside air through open windows, thermal chimneys, fans, or economizer cycles.

o Evaporative cooling involves evaporation of water into dry air streams, which then cool the indoor air.

o Earth coupling involves the conductive transfer of heat between living space and adjacent cooler earth areas. There are numerous earth coupling techniques: berming of building walls, underground construction, circulation of cool basement air into living areas, precooling of outside ventilation air through earth tubes, and circulation of well water in cooling coils.

o Night sky radiation is the radiant transfer of heat energy from a building to the cooler night sky, using roof ponds, trickle roofs, or high-emissivity skylights.

DRAWBACKS OF CONVENTIONAL GAS BACKUP SYSTEMS

After comparing backup system requirements with the abilities of conventional gas and electric heating and cooling systems, we found that conventional equipment has a number of deficiencies. For instance, no conventional backup system successfully combines whole-house air redistribution with zone control capability. The only conventional heating systems with zone control are gas boilers, electric baseboard heaters, and individual package terminal electric air conditioners (PTAC). These systems, however, lack the ability to redistribute solar-heated air among different rooms.

We also found that conventional cooling systems cannot efficiently handle latent cooling loads resulting from passive sensible cooling. Conventional AC systems assume an average sensible to latent load ratio of 70:30. Our preliminary analysis indicated that passive sensible cooling can reduce this ratio to 50:50 or even 100 percent latent.

Current electric AC equipment does not take variable sensible/latent loads into account. As the latent portion of the cooling load rises to 50 percent or more, the electric AC unit's COP drops by 10-20 percent. Supplemental electric dehumidifiers are very inefficient (COPs of about 0.7) and reject excess heat indoors, causing a net energy loss.

Another problem with conventional equipment is its inability to use 100 percent outside air. Two of the most common passive cooling techniques, forced ventilation and direct evaporative cooling, bring a considerable amount of outside air into the house. Since conventional residential furnaces and central heat pump air handlers do not have automatic economizer dampers and controls, separate blowers or fans for these systems are required. There are no available controls that optimize between the central AC system and the economizer fan or evaporative cooler. Thus both systems could run simultaneously, wasting more energy than they save.

A key problem from the gas industry's viewpoint is the lack of efficient conventional gas-fired cooling systems. Available gas absorption AC units are too inefficient to compete with electric AC at electric-to-gas (E/G) price ratios of less than 4:1.

Similarly, there are no safe, high-efficiency gas heating systems that can compete on a first-cost basis with electric baseboard heating. Using electric backup heating, a builder can price a passive solar house to compete economically with a conventional gas-heated house.

INNOVATIVE PASSIVE/GAS COMBINATIONS

Our analysis of backup heating requirements and the performance of passive heating and cooling techniques led us to develop requirements for improved passive/gas combinations. Based on these requirements, we identified four innovative passive/gas combinations, which are described below.

Multizone Gas Furnace. In homes with a 25-50 percent solar heat contribution, it is useful to have a backup system that recirculates air to prevent overheating of solar-heated spaces and to transfer warm air to remote rooms. Zone control would also help achieve maximum benefit from the passive heating/cooling features. Our proposed multizone furnace concept uses motorized control dampers located at the furnace heat exchanger outlet to achieve zone control. Individual zone thermosats control the damper motors. To maintain a steady air flow rate for each zone, the furnace incorporates proportionate control of circulation fan and burner motors. Each is adjusted downwards when either of the fan dampers is closed. When neither zone needs heat, the burner motor and fan motor both shut off. Alternatively, the motors could operate continuously with an infinitely adjustable speed control based on outdoor temperature. In either case, a small microprocessor performs these control logic functions. Exhibit I illustrates the multizone furnace concept and its use with a direct gain passive heating configuration.

Decentralized Gas Space Heater. In the Southwest and parts of California, a passive solar system can provide more than 50 percent of the home's heating needs, and an evaporative cooler can handle the summer's moderate cooling requirements. For this type of home, the gas

EXHIBIT I
Multizone Gas Furnace
Concept And Its Installation
in a Passive Solar Heated Residence

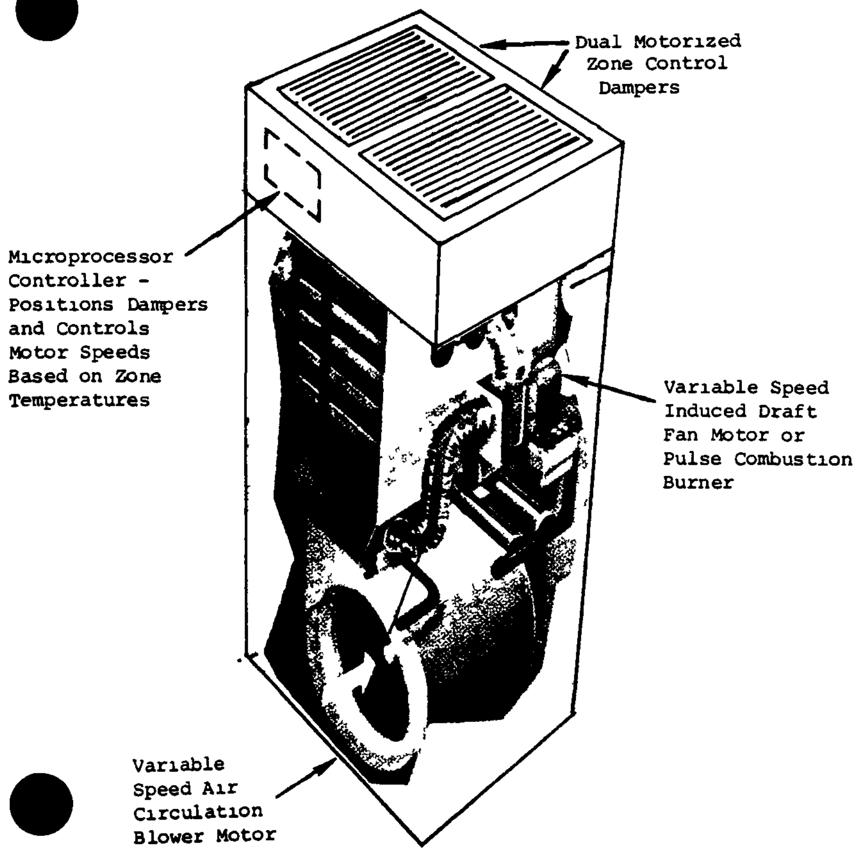
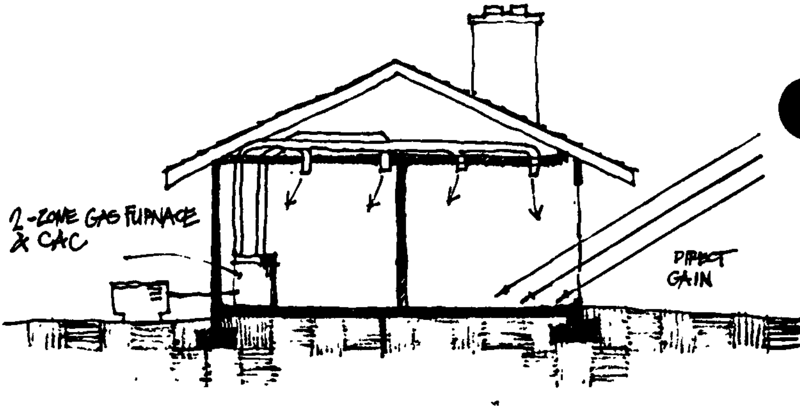
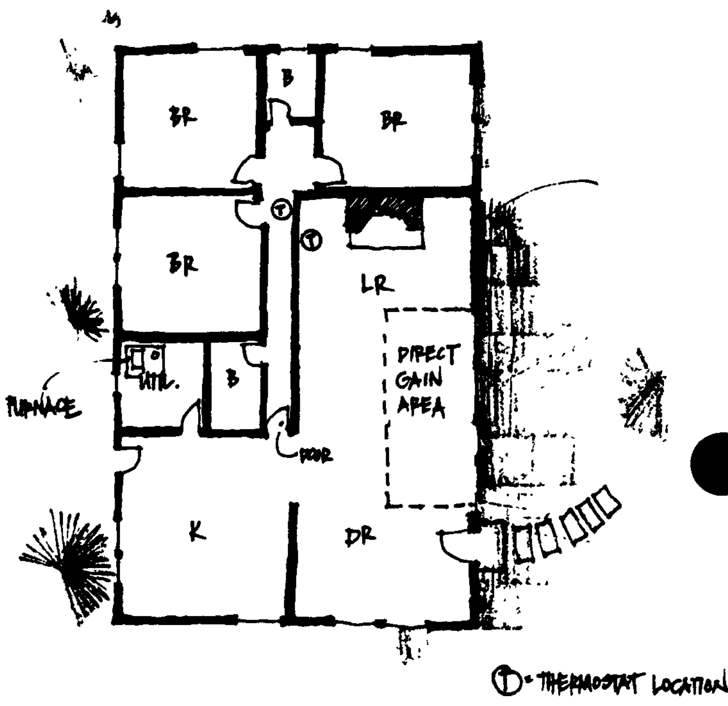


EXHIBIT I (Continued)





industry should offer an improved low-cost gas space heater with individual room temperature control. Field testing will be important in order to prove the unit's safety, performance, cost, and convenience.

High-Performance Gas Desiccant Dehumidifier. In many parts of the country, passive cooling can handle almost all of the sensible cooling load. In the north, natural and forced ventilation are sufficient. In the Southwest, evaporative cooling works effectively. In other areas, a combination of techniques -- such as ground coupling and solar load control -- can handle the sensible cooling load. After the air is cooled by these techniques, however, it is often quite humid and uncomfortable. To handle this residual latent heat problem, an auxiliary gas-fired dehumidifier could be developed. It would burn gas to regenerate a desiccant, and include heat recovery to improve its COP. It should have a COP of at least 1.5 to compete with technically feasible electric compression dehumidifiers with COPs of 2.0 at potential future E/G ratios as low as 3:1. Such a device could eliminate the need for electric AC. Exhibit II illustrates how this type of device could be installed.

High-Performance Gas Dehumidifier for Basement Drying. Gas-fired dehumidification could also be used for summer basement drying, instead of electric dehumidifiers. Although it would probably not eliminate the need for electric AC, it could reduce humidity levels considerably and thus improve the cooling system's operating economics. Cool, dry basement air could be mixed with the dehumidifier's warm return air to take advantage of the earth coupling effect. More than 10 million U.S. homes have basements and gas heat; half of these homes also have central AC, indicating a strong potential retrofit market for this type of equipment.

ECONOMIC AND COMMERCIAL VIABILITY

The above-mentioned systems are technically feasible, but are they economically and commercially viable? In order to provide GRI with practical recommendations, we had to analyze on a first-cut basis, their economics and commercial feasibility. We compared their economics with those of passive/electric systems, conventional gas systems, and conventional electric systems on a life-cycle basis in four locations which represent regions where innovative passive/gas systems are technically feasible: Albuquerque, Dallas, Minneapolis, and Philadelphia. The economic analysis methodology is explained in detail in our report to GRI. Exhibit III provides a sample of the computer model output. The results are summarized below.

EXHIBIT II
Configuration of a Gas Desiccant
Dehumidifier and Its Installation
in a Passively Cooled Residence

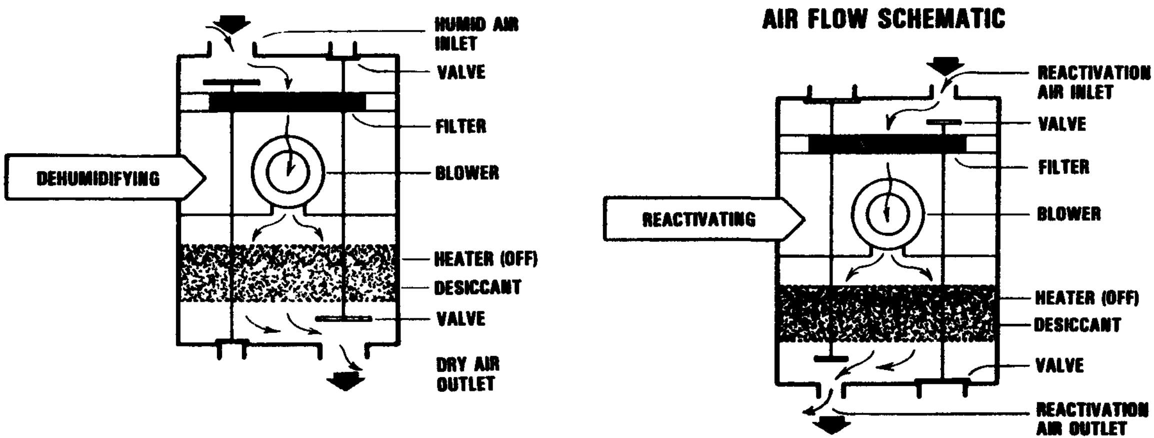
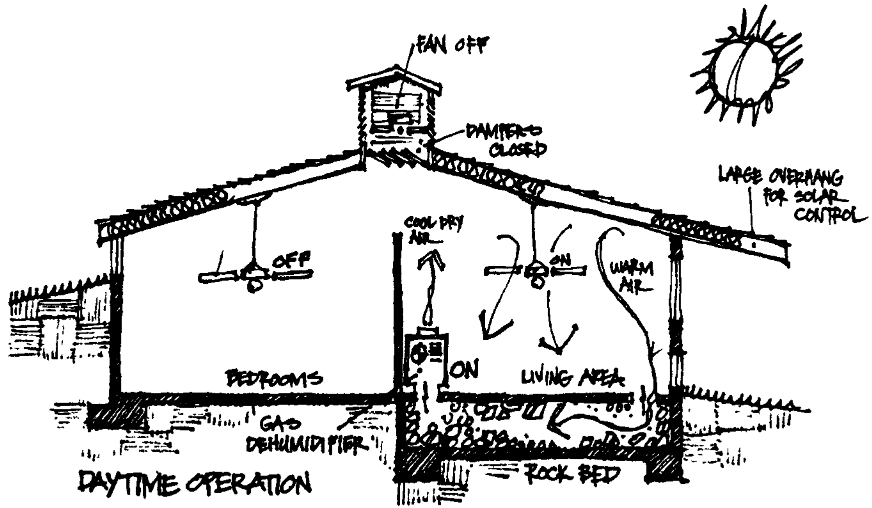


EXHIBIT II (Continued)



o The multizone gas furnace coupled with passive heating definitely appears to be economically feasible. This combination has a life-cycle cost 10-20 percent lower than any of the electric heat pump systems considered, either with or without passive solar. Furthermore, the multizone furnace alone offers a life-cycle cost saving of $1,000-1,500. It has an initial installed cost of only $300-400 more than a single-zone furnace, and offers 20-25 percent energy savings, resulting in a simple payback of three years or less.

o Gas space heaters offer low life-cycle cost when coupled with passive solar heating in milder climates. Because of its low initial cost, high efficiency, and zoning capability, this concept offers the lowest life-cycle cost option in Albuquerque and Dallas. It costs about $500 more than electric baseboard heat to install in a new home, but pays for itself in energy savings in less than three years.

o The high-performance gas dehumidifier coupled with passive sensible cooling appears to be economically viable where electric AC can be eliminated. In moderate cooling climates (e.g., Philadelphia), the gas desiccant dehumidifier along with passive sensible cooling eliminates the need for electric AC. We found that the life-cycle cost of the combination in Philadelphia is about equal to that of a conventional electric AC system. The gas desiccant dehumidifier (COP = 1.2) can compete on an energy cost basis with electric AC (COP = 2.8) at E/G price ratios down to 2.4.

o A high-performance gas dehumidifier alone would be much more economical on an operating cost basis than a conventional air conditioner. However, at an initial cost of $800-1,000 installed, the payback period is somehwat long at 7-8 years.

To assess the commercial viability of these systems, we interviewed 20 building industry and gas utility experts knowledgeable about passive solar technology and advanced HVAC equipment. The group consisted of five architects and engineers, five HVAC manufacturers, three gas utility representatives, and representatives of seven organizations involved in development of passive solar and advanced HVAC equipment.

This group gave highest marks to the multizone furnace. Gas and the dehumidifier were perceived as being interesting but need further work. Interviewees rated the multizone furnace highest for the following reasons:

EXHIBIT III
Example Output for
Economic Analysis Model

```
****** ALL DOLLAR AMOUNTS ARE IN 1982 DOLLARS. ******

INPUT PARAMETERS:
=================

   TAX AND INFLATION            INSTALLED COST & MAINTEN.    NATURAL GAS AND ELECTRIC COSTS
 =========================    ==========================   ==================================

   5.00 DISCOUNT RATE  -%                                     36.3 ANNUAL GAS CONS.    (MMBTU)
   1982 INIT INVEST. YEAR        1700 MAINT COST BASE-$       5.79 GAS PRICE YR1     ($/MMBTU)
   0.00 TAX CREDIT, FED-%        2.00 ANN MAINT. COST-%       3.30 GAS ESCAL. RATE (REAL)  -%
      0 MAX FED TAX CR.-$        0.00 MNT ESC RTE(REAL)          0 ANNUAL ELEC CONS.   (MMBTU)
   0.00 TAX CREDIT, ST.-%        1700 INST. COST  1  -$      22.87 ELEC PRICE YR1    ($/MMBTU)
      0 MAX ST. TAX CR.-$          20 ECON LIFE  1 -YRS       0.20 ELEC ESCL. RATE (REAL)  -%
                                 4300 INST. COST  2  -$
                                   20 ECON LIFE  2 -YRS

 DERIVED INPUT PARAMETERS
 ========================

    136 ANN CAP REC  1 -$
    345 ANN CAP REC  2 -$
     34 YR1 M&R COST   -$
      0 FED TAX CREDIT -$
      0 ST  TAX CREDIT -$
```

EXHIBIT III (Continued)

YEAR	INSTLD COST 1	INSTLD COST 2	GAS COST	ELECTRIC COST	MAINT & REPAIR COST	(**) TAX SAVINGS	NET CASH OUT-FLOW	DISCOUNT RATE	ANNUAL DCF(OUT)	CUMUL DCF(OUT)
1982	1700	4300					6000	1.00	6000	6000
1983	0	0	210	0	34	0	244	0.95	233	6233
1984	0	0	217	0	34		251	0.91	228	6460
1985	0	0	224	0	34		258	0.86	223	6683
1986	0	0	232	0	34		266	0.82	219	6902
1987	0	0	239	0	34		273	0.78	214	7116
1988	0	0	247	0	34		281	0.75	210	7326
1989	0	0	255	0	34		289	0.71	206	7532
1990	0	0	254	0	34		298	0.69	202	7733
1991	0	0	273	0	34		307	0.64	198	7931
1992	0	0	282	0	34		316	0.61	194	8125
1993	0	0	291	0	34		325	0.58	190	8314
1994	0	0	300	0	34		334	0.56	186	8501
1995	0	0	310	0	34		344	0.53	183	8683
1996	0	0	321	0	34		355	0.51	179	8862
1997	0	0	331	0	34		365	0.49	176	9038
1998	0	0	342	0	34		376	0.46	172	9210
1999	0	0	353	0	34		387	0.44	169	9379
2000	0	0	365	0	34		399	0.42	165	9545
2001	0	0	377	0	34		411	0.40	163	9708
2002	0	0	389	0	34		423	0.38	160	9867

1ST YEAR O/D COST 726

AVE DCF PER YEAR: 493

(1) Forced warm air is the most commonly used heat distribution system in new housing; (2) Multiple zone control alone can provide noticeable comfort improvements; (3) The incremental cost of manufacturing a multizone furnace is low, but it can be priced higher; (4) It takes advantage of the latest variable speed controls and electronics technology; (5) It can be added easily to existing product lines.

Gas space heaters coupled with passive solar space heating received a more lukewarm response. Externally mounted heating devices of any type are considered unattractive for new homes, and there is considerable concern about their safety. Their market may be limited to areas where central AC is not used. They also may be useful for sunspaces and greenhouses. Major HVAC firms consider this market too small to justify their participation at this time.

Passive sensible cooling coupled with gas desiccant dehumidification elicited mixed response. Those familiar with this technology suggested that 100 percent passive sensible cooling, although technically feasible in some areas, may be impractical or too expensive to achieve. Furthermore, it will take considerable field testing to convince home buyers and builders that gas dehumidification is as effective as electric AC. There is also considerable potential for improving the performance of electric dehumidifiers by using air-to-air heat exchangers; and the new heat pump water heaters on the market can provide dehumidification. If, however, these hurdles can be overcome, then this concept could have quite a wide spread appeal.

Gas dehumidifiers were of interest primarily to gas utilities and other industry players involved in retrofit markets. Despite the relatively high initial costs, there was a feeling that this could be reduced by mass production. A device of this type could be installed quite easily and would definitely enhance summer gas sales.

As a result of this analysis, we recommended that GRI move to develop a pilot version of the multizone gas furnace and conduct further R&D on gas space heaters and the gas dehumidifier. We also recommended further work on several new control schemes. The results of the project will help GRI establish near-term and long-term programs directed toward ensuring the gas industry's participation in the emerging market for passively heated and cooled new homes in the U.S.

DESIGN OPTIMIZATION OF GAS/SOLAR WATER HEATERS

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GENERAL ISSUES

For a variety of reasons, there has not been an emphasis in the residential market on the development of integrated solar water heaters using natural gas as the source of backup heat. Currently, there is only one domestic, residential system of this type commercially available, the Mor-Flo Solarstream G.A.S. produced by American Appliance Manufacturing Corporation. Two other systems are in different stages of development at Altas Corporation and Thermo Electron Corporation. The funding for the development of the Altas system was provided initially by the U.S. Department of Energy and subsequently by the Gas Research Institute. The Southern California Gas Company provided development funds for the Thermo Electron system. As a result of the lack of equipment on the market, the most common way to utilize gas backup is in a two-tank configuration with the backup provided by a standard residential gas-fired water heater.

There are various options which combine a solar preheat device and a backup method. One can use a pumped or a thermosyphon solar collection system, direct mixing or indirect heat exchange with the fluid in the preheat tank, and a two-tank system or single-tank integration of the heater and its backup. The combination of these options results in six fundamental generic types. Specific methods for accomplishing these functions create additional subsystem types which have different characteristics and consequently different performances. For example, indirect heat exchange may be accomplished through an external heat exchanger, requiring a pump for the stored water, or through an immersed coil heat exchanger. The latter option eliminates the need for a pump but suffers reduced heat exchange effectiveness due to the natural convection heat transfer on the storage water side.

Optimization of a solar water heating system can be done in a number of ways depending upon the assumptions one chooses to make. Strictly speaking, systems should be optimized from a total cost (life cycle cost) perspective. This implies that among the candidates for the most cost-effective system are those that operate entirely on conventional fuels. Such an optimization generally argues in favor of nonsolar systems even when the Federal and local tax credits are considered. These tax credits are expected to be reduced or eliminated totally in the future creating an even less favorable position for solar systems. When tax credits are included, solar assist becomes worthwhile only for users of purely electric water heating systems in sunny climates where the cost of electricity is relatively high.

Another approach to optimization is to consider what the best method is to back up a properly sized solar preheat system. Proper sizing is meant to imply a selection of collector surface area and storage volume size which makes best use of the available solar energy. At low outputs in a given demand schedule, the solar subsystem can be sized to operate thermally very efficiently (by maintaining low solar collector temperatures) but the cost of installation, including pumps, piping, and controls prohibits this approach from being economical. As a larger fraction of the load is placed on the solar preheat system a point of diminishing returns is reached where the incremental collected heat becomes progressively more expensive due to high resultant solar fluid temperatures. Having selected an optimum preheat design, one can then turn ones attention to the selection of a backup system to make up for the deficiency in total capacity which resulted from the optimal sizing of the preheater.

Users of gas water heating systems can well appreciate the usual benefit of gas versus electricity as a fuel source. Electricity is generated from a primary heat source at the powerplant with a final efficiency of about 30 percent by the time it reaches the user. Traditionally, gas-fired water heating systems have been designed largely for low first cost and net seasonal efficiencies can be as low as 50 to 55 percent although steady-state efficiencies of 70 to 75 percent are measured when the burner is operating. This has been adequate to maintain a market in gas water heaters. However, as gas prices rise due to deregulation, the economic advantage associated with gas is diminished. Consequently, there has been a significant development effort in the area of more efficient gas-only water heaters.

The improvement in gas-fired water heater efficiency generally is accomplished in two ways: improvement of the steady-state efficiency; and reduction of standby loss. Reduction of standby loss is most easily accomplished by the elimination of the center-flue design and by the switch from a burning pilot to pilotless ignition. Since gas water heaters can be of much smaller volume than electric water heaters, due to the ability to produce very high heat input rates more easily with a burner than with an electric immersion heater, elimination of the pilot and flue losses very nearly eliminates standby loss. Increases in steady-state efficiency are more difficult to accomplish in a cost-effective manner. Powered combustion as compared to atmospheric burners improves heat transfer and allows forcing combustion products through added heat exchange surface in a compact package. The cost of the power burner can discourage its use in small, residential-sized systems. Moreover, the requirement for electrical input for power burners and pilotless ignitions contradicts a long-standing tradition of producing residential gas water heaters which function independently of electricity and will continue to operate in the face of a utility power failure or a domestic electrical problem. In all solar systems except for the thermosyphon-type electrical input is required for pumps and controls anyway so that this traditional approach is not considered to be quite as important.

GAS/SOLAR WATER HEATING SYSTEMS

To the extent that there are no interface penalties (which is of course not the case) the single-tank design is preferred. This is due to the fact that floor space is conserved and two surfaces (the top of the preheat tank and the base of the backup tank) which lose heat to the environment are eliminated. Also, in an integrated design, the backup section can function by natural convection as additional preheat volume if the preheat water temperature exceeds the thermostat set point. This is an especially useful feature during the summer when many people disconnect the backup since an effectively larger solar storage tank is created. Lastly, excluding considerations of differing production lot sizes, a one-tank system should be able to be manufactured less expensively.

The economics of conventional gas-fired water heaters suffers more dramatically than that of conventional electric water heaters when used as backup in a two-tank system. In a normal duty cycle, a gas-fired water heater loses about 20 percent of its input to the environment compared to about 10 percent for an adequately large electric water heater whose storage capacity requirement is not compromised. Should the water heater be carrying only one-half the total load, the seasonal efficiency of a gas water heater can drop from 55 to 35 percent while the electric water heater efficiency drops from 90 to 80 percent. At one-third of total load (solar function = 2/3), the gas water heater can drop to 15 percent in seasonal efficiency while the electric water heater may drop to 70 percent. Clearly, elimination of the pilot and flue losses in a gas water heater can significantly improve its part-load performance.

In a two-tank system, the reasoning discussed above creates fairly clear guidelines for selection of a backup system. We, however, would like to evaluate ways to improve the economics of the integrated system so that a more cost-effective total package could be produced. As mentioned, with funding from both the Gas Research Institute and Southern California Gas Company, such efforts have been undertaken and have resulted in the development of two systems that represent the current thinking in residential gas/solar water heating systems.

In order to understand the possible range of issues involved, consider the test data in Figure 1 which were taken in the solar water heater test laboratory at Thermo Electron Corporation. Here, a 24-hour plot of temperatures at various levels in the tank is described. The test was performed on a 66-gallon integrated solar/gas water heater. The top 22 gallons, described by the top two nodes, is the backup section and contains a submerged 27,000-Btuh center-flue heating system with an atmospheric burner and a 600-Btuh pilot. The bottom 44 gallons, described by the bottom four nodes, is the solar preheat section. Water is pumped from the bottom, through an external heat exchanger where it is heated by the

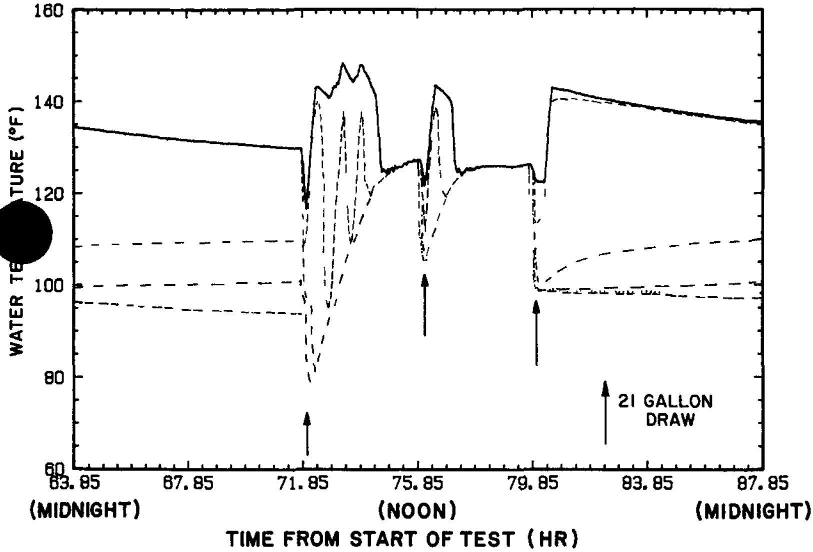

Figure 1. Thermal Response Characteristic
Heat Exchanger Flow = 4 gpm

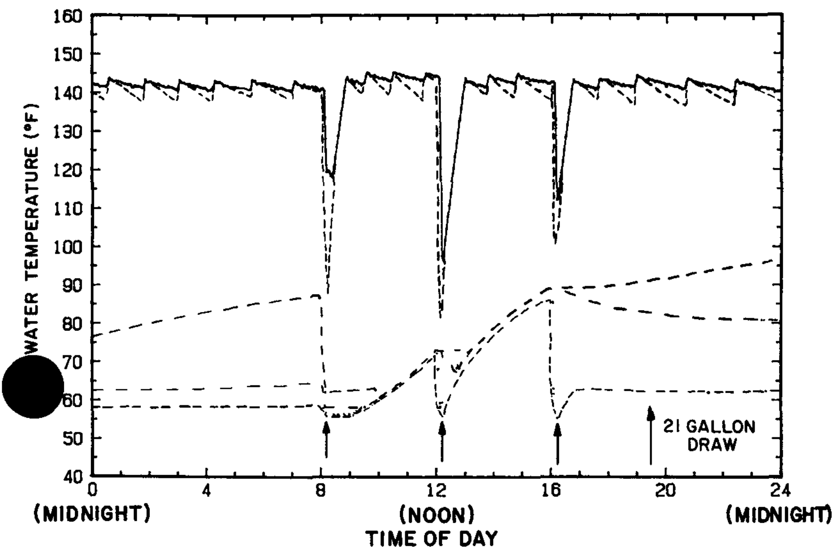

Figure 2. Thermal Response Characteristic
Immersed Coil Heat Exchanger

solar working fluid, an antifreeze solution, and back to the top of the preheat section below the combustion chamber. The water flowed at its recommended rate of about 4 gpm.

The test was performed using simulated solar heat input controlled to function with a temperature-dependent efficiency and a typical daily insolation characteristic. Three 21-gallon draws of water were made at 8 am, 12 noon, and 4 pm. This is a schedule recommended by ASHRAE for testing solar water heaters.

A number of points are clearly evident. During pumping of wate the solar heat exchanger, the preheat section is relatively well mixed. This creates higher water temperatures into the solar heat exchanger which increases collector operating temperature and reduces heat collection. Calculations on a pure preheat system have shown a 15-percent penalty under a typical set of conditions when mixing rather than when perfect water stratification occurs.

Mixing is more of a penalty here, however, since not only is the preheat section mixed but in reality the entire tank is mixed. Mixing from the backup to the preheater is accompanied by a delay, typically about one-half hour in duration but as soon as the backup section cools in the region of the thermostat (node 2) to below the lower end of the thermostat dead band, the burner is forced to operate. Numerous cycles of this sort are evident. Transporting heat from the backup to the preheater unnecessarily increases the backup contribution and through elevated preheat water temperatures further decreases the solar collection.

Heat is also transported eventually from the top of the backup section but the delay is a bit longer due to its distance from the preheat section. When the temperatures are high enough so that the lower set point is not reached, the tank becomes fully mixed as has occurred just prior to the noon draw. The second detrimental effect which is characteristic of center-flue gas water heaters is stacking. Normally, during a condition of repeated short draws which cause the burner to repeatedly fire, the water at the top of the tank heats beyond the set point. For safety reasons (to avoid scalding water at the end use point) limits are placed on the ultimate temperature attainable by this effect. In a gas-only water heater the penalty paid for stacking is primarily slightly higher losses to the environment. In a solar system, this effect causes the burner to heat water excessively in the backup portion. This reduces the gallonage demand (since people generally mix hot and cold water to achieve a desired temperature) and consequently the backup carries more of the load through the reduced passage of preheated water from the preheat to the backup section. Also, when mixing occurs, higher temperature water is transported to the preheat section, further diminishing the net solar collecti

Another detrimental interaction in the single-tank configuration is heat conduction from the backup to the preheat section. This is especially noticeable here overnight due to the 4 pm draw, which cools the preheat section just before solar collection ceases. The backup is hot overnight and the preheat section is cooler. The drop in temperature of the backup section and the rise in the upper portion of the preheat section is largely a result of this effect. In this case, the 8 am draw diminishes the impact of this heat transfer but should solar have begun before the morning draw, that effect would raise the mixed temperature of the preheat water again detrimentally affecting solar collection.

One way to eliminate all of the negative interaction except for heat conduction is to use an immersed heat exchanger. Solar collector fluid is pumped through a coiled tubular heat exchanger placed near the bottom of the tank. Heat transfer on the tank water side is by natural convection. As a result, effectivenesses tend to be low, being limited by the relatively poor heat transfer typical of natural convection, unless very large and consequently costly heat exchangers are used. A second detrimental effect is that, with the exception of the period just following a draw, the preheat tank functions in a well-mixed fashion and solar panel temperatures are higher than need be thereby reducing heat collection. No convective interaction occurs, however, with the backup section until the preheat water temperature exceeds the backup section temperature, at which time the interaction is an advantage in that the rate of rise in water temperature is decreased due to the additional heat capacity of the backup water. Figure 2 describes test data on such a system taken also in the solar water heater test laboratory. Backup input was provided by an electric immersion heating element. Note that the backup is relatively unaffected by the preheat process.

NEW CONCEPTS IN GAS/SOLAR WATER HEATERS

Figure 3 is a schematic illustration of an integrated solar/gas water heater developed by Altas Corporation for the Gas Research Institute. In this design, the preheat tank and backup tank are essentially separate but mounted with the backup above the preheat section. The two tanks are connected by a split-tube thermal diode which allows the preheated water to convect to the backup volume if it is at a higher temperature but inhibits mixing in the reverse situation. Insulation between the tanks inhibits conduction transfer. The preheat section uses indirect heat exchange with solar-heated water flowing through a jacket around the preheat tank wall. This inhibits mixing in the same way as an immersed coil but creates a degree of stratification by flowing downward through the jacket which covers nearly the full height of the tank.

Backup heat input is accomplished through a two-phase thermosyphon (TPTS) heat exchanger whereby a closed thermosyphon loop is established by boiling water at the burner and condensing in the backup tank. This design eliminates the standby loss experienced in the center-flue design since the TPTS heat exchanger will function in only one direction, i.e., adding heat to the water. A steady-state efficiency of 80 to 82 percent is reported. The ignition system uses an electric spark igniter to ignite a pilot flame which then ignites the main atmospheric burner. The elimination of the continuously burning pilot reduces the standby loss accordingly. Therefore, the seasonal efficiency is not significantly lower than the steady-state efficiency.

With funding supplied by Southern California Gas Company, Thermo Electron Corporation has developed a different concept in integrated solar/gas water heaters. A single 80-gallon tank is used. The water is contained within a rubber bladder separated from the steel tank wall by 1 inch of urethane foam insulation. Since 1/2 to 2/3 of the heat conduction is through the tank wall in a conventional design, this feature

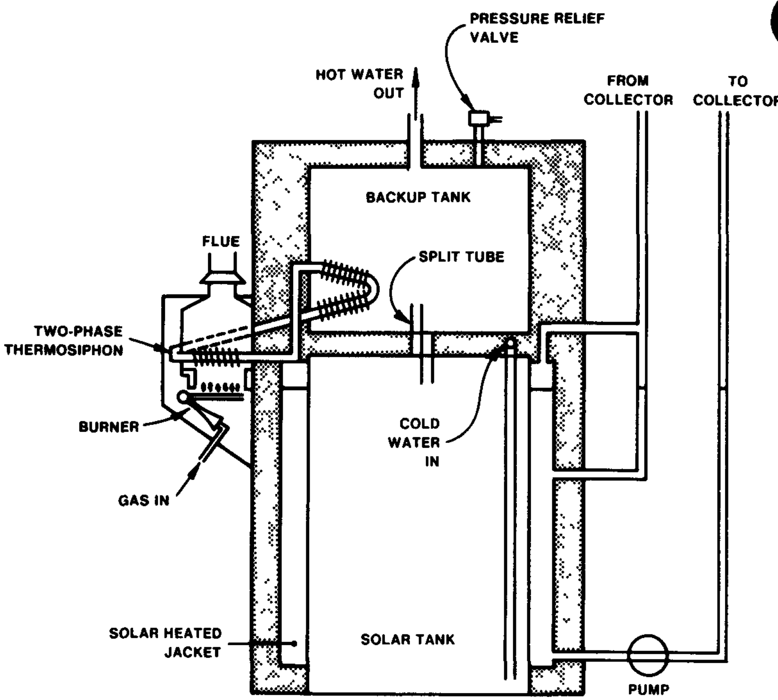

Figure 3. Schematic Illustration of Altas Solar-Augmented Gas Water Heater.

essentially reduces the conductive interaction to water conduction only. An insulating baffle between the preheat and backup sections has not been included but could effectively eliminate all of the conductive interaction.

Heat is added through a gas-fired heat pipe heat exchanger. Conceptually, this indirect heat transfer method is similar to the Altas method except heat pipes are used to transport liquid water and water vapor between the evaporator and condenser. The net effect is still to essentially eliminate the flue loss present in the center-flue design. A 35,000-Btuh blower burner is used instead of an atmospheric burner allowing steady-state efficiencies of 85 percent. An electric ignition system again eliminates the excessive and wasted use of gas by the pilot during standby. Again steady-state efficiencies at the backup can effectively approach instantaneous efficiency due to the near elimination of these standby losses.

The system uses an external solar heat exchanger the use of which would normally cause a significant amount of mixing, as demonstrated in Figure 1. However, a proprietary inlet water stratification promoter eliminates this effect. Water returning from the solar collectors is delivered to the level in the tank where the stored water closely matches the incoming water in temperature. Figure 4 describes the tank temperature response during a test run on this system with solar panels providing the preheat. Numerous short draws occurred during this test period. Overall one can see the stability of the backup section, i.e., no apparent mixing occurs. Second, the enlarged section shows the response in the preheat section during solar collection. The temperature spread from bottom to top is typical of the temperature rise in the solar panels and is maintained as temperature rises. As it drops due to reduced insolation and water draws to the load, the upper portion of the preheater remains hot since cooler water is returned to its appropriate level.

Another option being studied but not yet clearly reduced to practice is the use of a tankless gas-fired water heater to back up a solar preheat system. By using electric ignition to eliminate a burning pilot, standby losses are reduced to the cooldown of the water-to-flue gas heat exchanger after the burner is stopped. This is an ideal concept for gas-fired systems since it is easier to attain the high input rates required with no storage. In a residence, gas input can easily be over 100,000 Btuh while amperage considerations limit electric heaters to about 15,000 Btuh.

Tankless heaters respond only to a draw of water. When water flow is sensed, the burner comes on and heats the water to set point. With the storage capacity eliminated a number of control issues arise. First, a variable output atmospheric gas burner, unless it is elaborate and consequently expensive, has a turndown ratio limited to 3:1 or 4:1. This is a troublesome but not a severe limitation in a system which always receives cold water from the water main. In a solar-preheated system, the practical turndown requirement due to elevated inlet water temperature and fixed outlet water set point can be 10:1 or 12:1.

The presence of a solar storage capacity can alleviate this concern in a number of ways. One method under consideration uses the tankless heater to preheat a portion of water at the upper end of the storage tank to something closer to set point. Now the tankless heater, during a draw

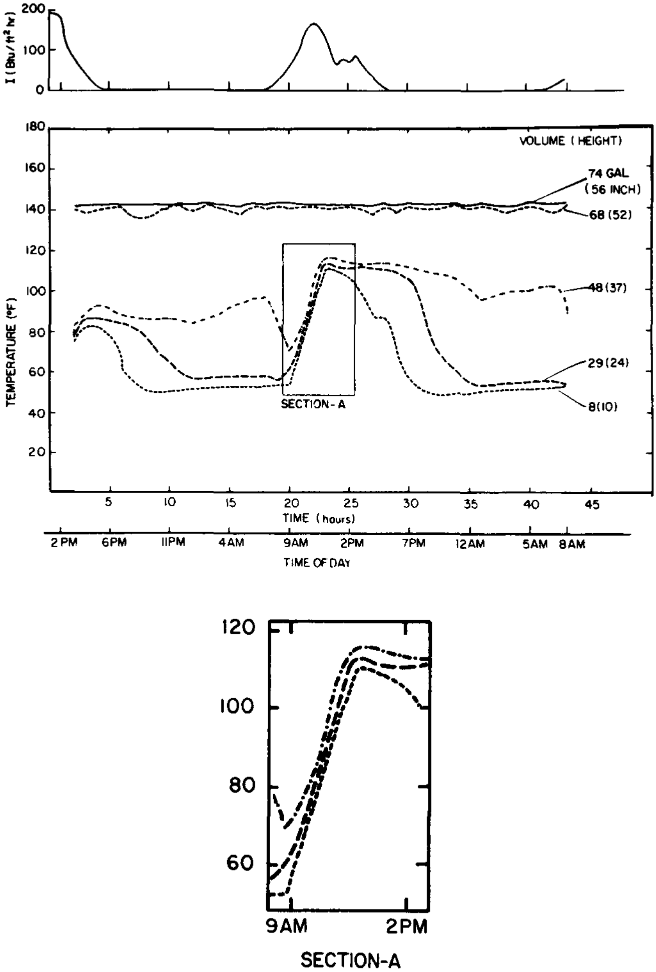

Figure 4. TES: Tank Temperature and Insolation versus Time

can be operated within a tolerable turndown ratio and the burner output can be reduced due to the guaranteed preheat. The preheat temperature can be set so that under conditions of high solar collection, the upper storage is available when solar water exceeds this preheat temperature.

Another concept retains the normal solar storage temperatures except during a draw. Water is drawn through the tankless heater and pumped back to the upper portion of the storage tank. If the draw, which is taken from the outlet of the tankless heater equals the throughput then no heated water is returned to storage. When the draw is lower, the water returns to storage creating an effective preheat. With judicious selection of either a variable flow pump or a modulating flow splitter and a manageable turndown ratio, the return of water to storage will only occur under high preheat, low flow conditions.

CONCLUSIONS

Unless steps are taken to design solar/gas water heaters specifically for high efficiency at part-load duty, natural gas systems can suffer dramatic efficiency penalties. The use of indirect, two-phase heat exchangers and electric ignition can easily accomplish this. Standby flue loss from the water to the environment is eliminated through the use of two-phase heat transfer which operates in one direction only. The consumption of natural gas during standby is eliminated through the use of electric ignition. The compact storage volumes allowed by the high heating rates of a natural gas burner reduce the surface losses. Overall, therefore, annual efficiencies can closely approximate the high (80 to 85 percent) steady-state efficiencies associated with burner operation.

Elimination of interface effects between the preheat and backup sections can increase the solar fraction thereby reducing the backup heat requirement. This can be accomplished by a split tube thermal diode as in the Altas system or by a low conductivity containment (possibly including an insulating internal baffle) in addition to a stratification promoter which inhibits mixing. The stratification promoter improves the performance of the preheat section allowing the use of high effectiveness external heat exchangers without the consequent mixing experienced by other systems. The elimination of interface effects and the promotion of stratification are steps which could also improve the performance of any integrated system.

A fundamental observation may be made which is that, in general, interactions between preheat and backup should be avoided since they can only impair the solar heat collection. Extracting the maximum amount of heat per unit panel surface area is critical to the cost effectiveness since solar equipment represents a high first cost which is paid back by future energy savings. The colder one can deliver water to the collectors, the more heat they are able to collect. Thermal stratification helps to improve heat collection.

A preferred backup device is a tankless gas-fired water heater. High heating efficiencies and minimal standby losses create a high annual efficiency. The existence of a solar storage tank creates an opportunity to deal with the control problems which could accompany the use of such devices in an application requiring a wide range of heat input rates.

Tankless heaters can be compact and can be easily mounted above the preheat tank creating a compact package. Further work is planned to evaluate the economics of such a system in comparison to the various storage heater backup concepts.

HAVERHILL: A LARGE-SCALE INDUSTRIAL GAS/SOLAR ENERGY SYSTEM

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I. INTRODUCTION

The U. S. Department of Energy, the Columbia Gas System Service Corporation and the USS Chemicals Division of United States Steel Corporation are jointly funding a project to design, construct, operate and evaluate a large-scale solar energy system to provide industrial process steam for the USS Chemicals plant near Haverhill, Ohio.

The Haverhill Solar System design phase was completed in September, 1980 and solar system construction was completed in January, 1982. The U.S. Department of Energy, Columbia Gas and USS Chemicals conducted acceptance testing of the system during the period February through May, 1982.

The Haverhill solar energy system has been operating unattended since June, 1982. The system will be operated, maintained and evaluated over a 30 month period. An on-site data acquisition and data processing system is installed at the site. Solar system availability has averaged over 70 percent for the first eight months of operation, which is considered good for the advanced technology components used in the Haverhill system. Solar collectors have performed at design efficiency during operational periods. The solar system design goal is to deliver 8 billion BTU's annually.

HAVERHILL SOLAR ENERGY SYSTEM

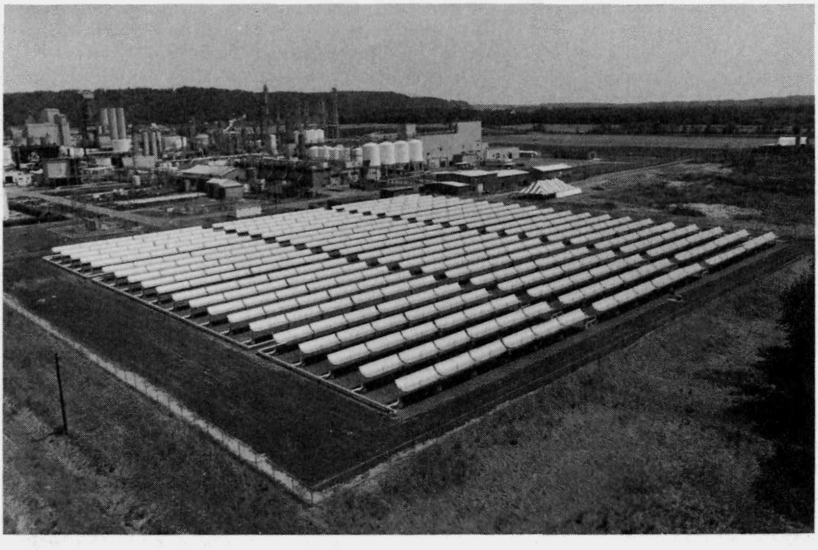


Figure 1

The Haverhill solar energy system occupies an area of approximately 3 acres. The solar system has 60 separate solar collector rows, arranged in three banks of 20 rows each, as can be seen in the aerial photograph. Each row has six reflector panels, and each of these panels has an aperture area of 140 square feet. The 360 ground mounted, single-axis tracking, concentrating solar collectors have a total aperture area of 50,400 square feet.

HAVERHILL SOLAR SYSTEM SCHEMATIC

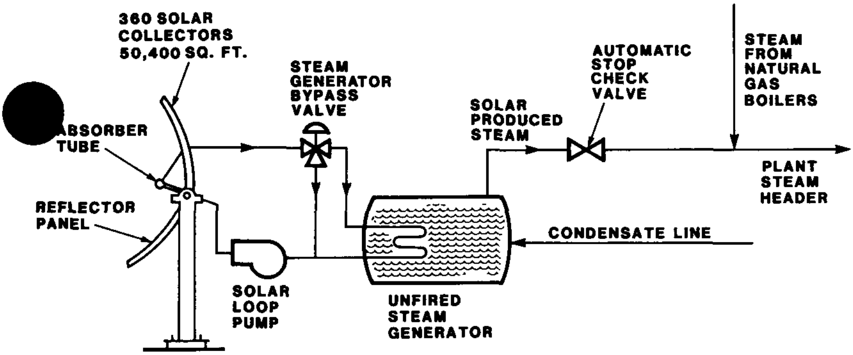


FIGURE 2

A schematic of the Haverhill solar energy system is presented in Figure 2. A heat transfer fluid is pumped through the solar collector array to a steam generator at a nominal flow rate of 320 gpm. The design maximum solar collector outlet temperature is 500°F. The solar system is designed to produce steam at pressures up to 150 psig.

Steam produced by the Haverhill solar energy system is currently utilized in the phenol plants at USS Chemicals. The phenol plants require steam at 450, 150 and 50 psig. The solar produced steam is fed into the 50 psig steam system. The phenol plants' process loads exceed the maximum solar system steam output of 10,000 lbs/hour at all times when they are in operation, and no solar energy storage system is required at this solar site.

Steam for the USS Chemicals plant complex is generated with steam generators using primarily natural gas as a fuel, although portions of the plant's total steam requirements can be produced with oil, coal, and now solar energy.

II. SOLAR SYSTEM DESIGN STRATEGIES

There are usually basic conditions imposed on an industrial process heat (IPH) solar system design; e.g., the time/energy requirement profile of the process load, the temperature required by the process load, and the climate. The time/energy requirement profile of the process load influences the size of the solar collector array, and the size of any thermal energy storage subsystem. The temperature required by the process load impacts many aspects of the solar system design, including the type of solar collector, the solar collector loop fluid, the solar collector loop pumps and the type of interface equipment required between the solar system and the process load.

The solar system designer often has significant latitude to select solar system features and components within the constraints of the basic conditions imposed. The information in this section presents the design philosophy and the primary considerations used by the Haverhill solar energy system design team in the selection of solar system features and components.

A. Solar Collector Selection Considerations

The most important factor in designing a solar energy system is the selection of a solar collector that represents an optimal tradeoff between cost and efficiency. The solar collector efficiency should be high in the operating temperature range of the system.

The Haverhill solar energy system was designed to produce industrial process steam at pressures up to 150 psig. Solar collector outlet temperatures of the order of 450°F to 500°F are required to produce steam at 150 psig. Solar collectors that operate efficiently in this temperature range are limited to line focus and point focus collectors. For the solar radiation conditions at Haverhill, Ohio, and for the temperatures required at the USS Chemicals - Haverhill plant, point focus, double-axis tracking solar collectors would capture approximately 20 percent more solar energy annually than line focus, single axis tracking collectors. However, the installed cost of point focus, double-axis tracking collectors was several times the installed cost of line focus solar collectors at the time of the Haverhill design phase. Therefore, for the Haverhill application, line focus collectors deliver more energy for each dollar of installed solar system cost.

We selected line focus collectors as the most cost effective for the 450° to 500°F temperatures required at Haverhill.

The design team evaluated line focus collectors from four different collector manufacturers during the Haverhill design phase. Based on collector cost quotations, estimated installation cost, estimated maintenance cost, measured single collector peak collection efficiency, estimated solar collector array seasonal performance, and estimated solar collector life, the Solar Kinetics, Inc. (SKI) T-700 single-axis tracking solar collector was selected for the Haverhill application.

B. Solar Collector Loop Fluid Selection

As shown in Figure 2, the Haverhill solar energy system has a separate solar collector loop that recirculates a heat transfer fluid from the solar collectors to a steam generator. As in many areas of the U.S., winter temperatures in Haverhill, Ohio are frequently below 32°F. It is not feasible to use water for the solar collector loop heat transfer fluid unless the water is heated in the pipes or drained into heated vessels during periods when the solar system is not in operation and temperatures are below freezing. These approaches are not energy efficient and are costly to implement. Therefore, a non-freezing, petroleum-derived heat transfer fluid was selected for the solar collector loop working fluid.

The solar collector loop fluid selection impacts many aspects of the solar system design: pumps, pipe sizes, steam generator, expansion tank, valve packings, etc. There are a host of technical parameters that can be considered in selecting a heat transfer fluid for a large scale solar energy system. The following list of physical and thermal characteristics plus cost data were judged to be the most important for the Haverhill solar system application:

- Long term stability at 550°F
- Heat transfer efficiency factor
- Viscosity at 0°F
- Toxicity
- Cost
- Flammability

1. Long Term Stability at 550°F. - The Haverhill solar energy system is designed to operate with collector outlet temperatures of up to 500°F. There are heat transfer fluids available from several suppliers with suggested continuous service temperatures of 500°F or higher. A primary consideration of the Haverhill solar energy system design team was the long-term stability of the heat transfer fluids operating at this temperature. With bulk fluid temperatures up to 500°F, it was estimated that fluid film temperatures in the solar collector receiver tubes would be as high as 540°F on some occasion. Long term stability test data for the candidate heat transfer fluids was obtained from the manufacturers. We decided to select a fluid with a decomposition rate that did not produce greater than 1% low boilers for an 1800 hour thermal stability test at 550°F. (Low boilers is an arbitrary term used in the industry to denote thermally cracked fluid or fluid decomposition to light fractions with a molecular weight lower than the lowest molecular weight constituent in a new sample of the same fluid. 1800 hours represents approximately 1 year of solar collector operation at Haverhill).

2. Heat Transfer Efficiency Factor - We conducted a heat-transfer efficiency analysis for twelve candidate heat transfer fluids. For this analysis we computed a heat transfer efficiency factor (HTEF), which is an expression of the ratio of the heat transfer coefficient to the frictional energy expended pumping the fluid. In this analysis the HTEF increases with increasing values of specific heat, thermal conductivity, and density and decreases with increasing values of viscosity. The reader is referred to the Haverhill Final Design Report for more information on the heat transfer efficiency factor calculations and the physical properties for the twelve heat transfer fluids considered for the Haverhill solar system.

3. Viscosity at 0°F. - From a solar system design standpoint, it is a benefit to have a heat transfer fluid with a low viscosity (less than approximately 300 cs) at 0°F. The heat transfer fluid in the solar collector loop will approach ambient temperature if the solar system has not been in operation for some period of time due to cloudy weather. If the fluid has a sufficiently low viscosity at this minimum daytime winter temperature (approximately -5°F in Haverhill, Ohio) it can be pumped with centrifugal pumps. Positive displacement pumps must be incorporated in the solar system design (to meet start-up conditions) if the viscosity of the heat transfer fluid is high at the expected minimum winter temperature.

Incorporating positive displacement pumps in a solar system design can have a definite cost impact, particularly if the positive displacement pumps must be capable of operating at high temperatures. The solar system designer should carefully consider this impact of the fluid viscosity at low (system start-up) temperature on the solar collector loop pump selection.

4. Toxicity - The toxicity of the fluid is a very important design consideration. Fluids that are non-hazardous materials according to the U.S. Department of Labor criteria simplify the solar system design. The Haverhill solar energy system design team obtained Occupational Safety and Health Administration (OSHA) Material Safety Data Sheets for candidate heat transfer fluids. The selection of a non-hazardous heat transfer fluid according to the U.S. Department of Labor criteria reduced solar system costs and facilitated the preparation of the Environmental Assessment and the Safety Analysis for the Haverhill solar energy system.

5. Cost - The cost of heat transfer fluids varies over a wide range. The analysis of the first cost of the fluid is an obvious design consideration. However, the analysis of the impact of the heat transfer fluid selection on the balance of solar system cost is not so straight forward. The solar system designer should, at a minimum, evaluate the approximate installed costs and approximate operating costs of the solar collector loop pumps that would be required with any candidate heat transfer fluid. It is possible to have a higher cost heat transfer fluid result in both lower total solar system installed costs and lower operating costs.

6. Flammability - The twelve heat transfer fluids considered for the Haverhill solar energy system were evaluated for flash point, fire point and auto ignition temperature. In general, only heat transfer fluids with a fire point above 300°F, a flash point above 300°F and an auto ignition temperature greater than 700°F were considered for the Haverhill application. (Refer to Haverhill Final Design Report for further details.)

Monsanto Therminol 60, a polyaromatic synthetic fluid, was selected for the Haverhill solar collector loop fluid. Therminol 60 has demonstrated excellent stability at 550°F during long term testing. The heat transfer efficiency factor of Therminol 60 is very good relative to the eleven other candidate fluids considered for the Haverhill solar energy system. The heat transfer efficiency factor of Therminol 60 is 23.0 at 400°F and

26.9 at 500°F. The viscosity of Therminol 60 is 65 cs at 0°F, which is excellent for a high temperature heat transfer fluid. Therminol 60 is classified as a non-hazardous material by the Department of Labor Occupational Safety and Health Administration. A disadvantage of Therminol 60 is the relatively high current cost of $15.65 per gallon.

The selection of Therminol 60 eliminated the need for positive displacement solar collector loop pumps, which would have been required for cold weather system start-up with a more viscous heat transfer fluid.

C. Solar Collector Field Layout Considerations

By agreement of the project funding partners, a solar collector array size of 50,400 square feet was selected for the Haverhill installation. The Solar Kinetics, Inc., Model T-700 solar collector selected for the Haverhill solar system has an aperture area of 840 square feet for each row. Sixty rows, or a total of 50,400 square feet, of SKI solar collectors were selected for the Haverhill solar energy system.

The Haverhill solar energy system design team attempted to define a solar collector array layout, coupled with a selected heat transfer fluid and a selected total solar collector array heat transfer fluid flow rate, that optimized the solar system cost effectiveness. We determined or estimated the following solar system performance related parameters after the above three basic independent variables - (1) solar collector layout, (2) heat transfer fluid type, and (3) heat transfer fluid flow rate - were selected.

- Solar Energy Collection
- Solar Collector Loop Temperatures
- Solar Collector Loop Pressure Drop
- Solar Collector Array Fluid Volume
- Solar Collector Array Cool-Down Losses
- Solar Collector Array Operating Losses

The rectangular grid of roads at the USS Chemicals plant complex is parallel and perpendicular to the Ohio River. "Plant North" is 65° East of true North. "Plant East" is 65° South of true East, etc.

The design team studied numerous solar collector array layouts and piping layouts that included 60 rows, or 50,400 square feet, of solar collectors. Candidate solar collector layouts with a solar collector axis parallel to plant N-S and plant E-W were evaluated. We also evaluated solar collector layouts with a solar collector axis parallel to true N-S and true E-W. Solar collector arrays with fluid flow through two, three and four collector rows in series were evaluated.

1. <u>Solar Energy Collection</u> - The candidate solar collector layouts were computer modeled to determine the effects of the four different solar collector orientations (plant N-S, plant E-W, true N-S and true E-W) on the annual energy collection. The TRNSYS program from the University of Wisconsin was used for this analysis. We developed a new solar collector subroutine for the TRNSYS program to simulate the performance of the SKI Model T-700 solar collector. The results from the TRNSYS computer runs using Huntington, W. Va. solar weather data suggest that annual solar energy is maximized when the solar collectors are aligned true N-S. However, relatively modest decreases in annual solar energy collection would be expected when the solar collector is not aligned true N-S. The computer analysis suggests about 1% decrease in annual solar energy collection for each 10 degrees the solar collector axis is rotated away from true N-S.

The Haverhill design team elected to align the solar collectors with the orthogonal axes established by the roads and streets within the plant compound in order to conserve valuable land area. The solar collector axis runs 25° west of true north (or concomitantly 25° east of true south).

2. <u>Solar Collector Loop Temperatures</u> - After initial solar collector loop warm-up in the morning, the solar collector inlet temperature at Haverhill is largely controlled by the steam generator design and the steam generation pressure. The Haverhill design team selected a maximum design steam pressure of 150 psig. When operating at this steam pressure, the solar collector inlet temperature is nominally 390°F.

We designed the solar system to have a maximum solar collector outlet temperature of 500°F when maximum solar radiation is available. We selected this maximum temperature for two reasons: (1) to reduce the potential for thermally cracking the heat transfer fluid in the solar collector loop over a long period of time, and (2) to reduce the potential for damaging the silicone rubber seals in the solar collector receiver tube joints.

This basic decision limited the solar collector piping arrangements to those having fluid flow through a maximum of three solar collector rows in series. For the Haverhill design, four solar collector rows with fluid flow connected in series would produce solar collector outlet temperatures higher than 500°F, or alternatively a higher pressure drop and higher pumping horsepower requirement for the solar collector loop.

3. Solar Collector Array Fluid Volume - A basic design goal for the Haverhill solar energy system was to minimize the fluid volume in the solar collector loop. The fluid mass in the solar collector loop is thermal inertia for the solar system. The solar collector loop fluid mass and piping cools down at night. This night time cool-down is a solar system loss that must be made up during the next day that sun is available. Energy collected by the solar collectors must first heat the solar collector loop fluid to system operating temperature before any useful energy can be delivered to the process load. Night time cool-down losses are minimized to the extent the solar collector loop fluid can be minimized.

The final Haverhill solar collector array layout is square, 400 feet by 400 feet. As can be seen in Figure 3, there is a single solar collector inlet main and a single solar collector outlet main. Heat transfer fluid is pumped through 20 parallel strings of solar collectors. Each solar collector string has three individual solar collector rows placed end-to-end. Solar collector mains are sized with small diameters that produce fluid flow rates of the order 4 feet/second throughout the solar collector loop. Additionally, the solar collector mains are stepped down in size from a maximum of 6 inch diameter at the near end of the field to a minimum of 2½ inch diameter pipe at the far end of the field. The reduced diameter piping, single inlet main, single outlet main, and square solar collector array layout possibly approaches the minimum solar collector loop fluid volume that can be achieved with a 50,400 square foot solar collector array. The Haverhill solar collector loop has a distributed heat transfer fluid inventory of 0.06 gallon/ square foot of active solar collector area.

HAVERHILL SOLAR ENERGY SYSTEM FIELD LAYOUT

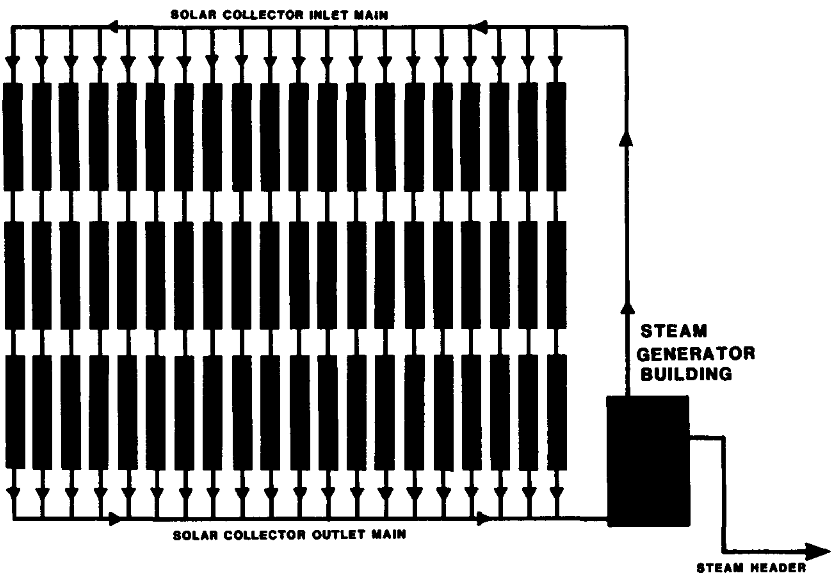


FIGURE 3

AUTHORS

Mr. Phil Dechow is a Senior Research Engineer with the Columbia Gas System Service Corporation, Columbus, OH. Mr. Dechow was the Principal Investigator on the Haverhill solar energy system. Mr. Lowell Mast is Vice President of H. A. Williams and Associates, Inc., Consulting Engineers, Columbus, Ohio. Mr. Mast was in charge of all consulting engineering activities on the Haverhill project. Mr. Edward A. Reid, Jr. is the Manager of Residential and Commercial Utilization Research for the Columbia Gas System Service Corporation, Columbus, Ohio. Mr. Reid was the Program Manager and had overall responsibility for the Haverhill solar energy project.

The authors would particularly like to acknowledge major contributors to the success of the Haverhill solar energy project: Mr. Stan Demski, Plant Manager, USS Chemicals - Haverhill Plant; Mr. Al Walker, Plant Superintendent, USS Chemicals - Haverhill Plant; Mr. William Nettleton, IPH Program Manager, U.S. Department of Energy - San Francisco Operations Office; Mr. Jim Lockard, Lead Mechanical Consulting Engineer and Mr. Tom Huff, Lead Electrical Consulting Engineer, H. A. Williams and Associates, Columbus, Ohio; and Mr. Robert Schwendenman, Project Manager for Sauer Mechanical, Columbus, Ohio, who was in charge of all construction activities at Haverhill.

RETROFITTING OIL AND GAS BOILERS WITH A WOOD GASIFICATION SYSTEM

John C. Calhoun, Jr.
Forest Fuels Manufacturing, Inc.
Marlborough, New Hampshire

Forest Fuels has spent eight years developing, testing, selling, and installing industrial gasifiers in the 500,000 to 17 million Btu per hour range. To date, we have twelve gasifiers operating in customers' plants. In two instances, the US Department of Energy provided financial assistance to our customers for the commercialization of our gasification technology.

While our effort has not been without its learning curve, we are proud of our accomplishments to date, and the savings that our customers have been able to realize. Our first unit installed in September, 1975 is still in daily service. A number of our systems have operated 24 hours a day, 7 days a week, for up to three years with minimal but careful attention and routine maintenance. There has been enough merit in our technical thrust so that I can tell you that, where the economics were favorable and the owners and operators were as dedicated as the Forest Fuels staff, the systems were made to work successfully.

In the United States there are roughly 310,000 boilers of all kinds in the 150-400 horsepower range fired by oil or natural gas. In the 20-100 horsepower range, there are another 900,000 units.

The Forest Fuels mission from the start was to develop a safe, economical, simple gasifier that could retrofit these boilers and offer the ability to use a relatively cheap, renewable, native, and presently wasted fuel. By converting the solid fuel to a clean gas in a simple vessel, the gas can then be fired in the boiler firebox without de-rating the boiler.

It is generally recognized that wood in its raw state --1/2 solid and 1/2 water--has, roughly, 4200 Btu per pound, but has over 8,000 Btu/lb in a dry state. So, in order to achieve economies of scale, maintain boiler efficiency and boiler rating, Forest Fuels developed an appropriate sized dryer to produce dry fuel for our system. The dryer utilizes stack gases that would normally vent to the atmosphere. The hot gases are passed over the "green" fuel, the moisture is driven out, and the result is approximately 15% m.c. wet basis fuel available to the gasifier. The gasifier has been designed only to burn dry fuel. The primary reason for this is one of efficiency; that is, the boiler must handle all of the moisture driven out of the burning wood, which directly affects the efficiency of the boiler. According to research data appearing in the August 1981 Forest Products Journal, 50 percent moisture content wood reduces boiler efficiency to roughly 65 percent from 77 percent at the 15 percent moisture content level (1).

In the case of 250 HP average requirement, this means that more wood will be required to get the same output as our gasifier is capable of producing with 15 percent moisture content wood from the dryer. Specifically, 12 percent more wood per hour will be required to get 250 HP. More importantly, the physical limitations of the boiler may be such that it is impossible to draw more gas volume through the boiler tubes without further reducing its efficiency.

From a cost effectiveness standpoint, there are two points to be considered. The first, already mentioned, is that 12 percent more wood will be required to get 250 HP equivalent from 50 percent moisture content wood.

Secondly, higher moisture content requires more fuel to be burned to evaporate the water in the wood. What happens is that energy, i.e., wood, must be used to heat the water and vaporize it, and only then does the remaining energy available in the wood go to heating the boiler. This circumstance requires that an additional eleven per-

(1) Forest Products Journal, "Potential for Compression Drying of Green Wood Chip Fuel", John G. Haygreen, Vol. 31, No. 8, August 1981, pg. 44.

cent of wood input is required to achieve the desired boiler output.

The net effect is that 23 percent more fuel will be required burning wood wet versus the Forest Fuels approach which utilizes waste stack heat for drying.

What does this mean as far as dollars are concerned?

To replace the approximately 165,000 gallons of oil burned at one of our customer's facilities last year, using the Forest Fuels approach will require approximately 3,400 tons per year of green wood. To replace the same amount of oil with a system not using a dryer would require 4262 tons per year. At $15 per ton, the cost for wood fuel will be 19 percent higher annually by not using the Forest Fuels approach. In dollars, this is almost $12,000 more cost per year.

Said another way, the savings over oil will go from 63 percent to 46 percent annually when a dryer is not used in the system.

We started with a "simple" cross-draft gasifier using a slanted gasifier vessel, and that is what Forest Fuels will continue to use, although we did develop traveling grate gasifiers and have a number of units working quite successfully in the field at this time.

One learns very quickly in the wood energy business that the weak link of solid fuels energy systems is the fuel delivery equipment. The best combustor in the world is helpless with a bridged fuel bin shutting off the supply. Therefore, Forest Fuels places great emphasis on a complete system from chip truck unloading, storage, screening out over-sized chips, and fuel chip conveying. Before they were available, our engineers had to develop appropriate handling systems for handling less than one thousand pounds of fuel per hour, when the pulp and paper industry requires equipment to handle many tons per hour.

These systems must be presented to a customer at a cost that, when computed with the price of the fuel chips and the fuel--gas or oil to be replaced-- will generate a return on the capital invested that will match or exceed other options for the available capital. As a general rule, the Forest Fuels customer will see a return on the capital invested in our systems in 3 1/2 years or less. Should they produce their own fuel, particularly where the fuel is dry, investment can be recovered in months--not years. We have seen internal rate of return at 50 percent or more on our wood energy systems.

In enterprises where the price of energy makes up a quarter to one-half of the cost of the product, energy savings are a matter of survival. These are the people that could use a gasifier. This is particularly true in the northeastern states where the forests cover well over half of the landscape and are woefully underutilized. The potential energy reservoir waiting to be tapped in the forests of this country has been estimated by the U.S. Forest Service and the Comptroller General of the Accounting Office of the Federal Government as the equivalent of 1.3 billion gallons of oil a year on a renewable basis(2). Indeed, the controlled removal of this material, the rough and rotten trees unsuited for lumber and far too abundant for pulp markets to absorb, would improve the health, quality, and productivity of our nation's forests and provide a needed market for trees killed by disease or insect attack. Of course, this would improve the local economies very dramatically.

At this writing, in the northeast the delivered cost for one million Btu's from #2 oil is $7.14, #6 oil is $4.67, natural gas is $6.70, and coal (in less than train lots) is $4.60. Compare this with the average price of wood chips, $2.25 per one million Btu's.

The question of availability of wood fuel in chips is always raised. Will there be enough fuel? Won't the price rise out of sight with increased demand? The answer coming from all the forested areas of the country, and the U.S. has 500 million forested acres, is that "the total consumption of wood used as fuel will be limited by demand for rather than the supply of the wood resource," a quote from forestry professor Robert Harris of Clemson in the November 1982 Forest Products Journal(3).

Already the pulp and paper industry uses one and one-half million tons of chips. But the resource is said to be 600 million tons per year. This is annually produced and wasted while the country is so dependent on OPEC. The equipment and know-how is in place to begin to utilize this resource. What has been needed is combustion equipment and systems to relate this fuel to the commonly used energy equipment found in the factories and institutions of the small to medium energy user.

(2) Comptroller General's Report to Congress, The Nation's Unused Wood Offers Vast Potential Energy and Product Benefits, March 3, 1981.

(3) Forest Products Journal, "Market Potential for Wood Fuel -- A Limiting Factor in Wood Energy Development", Robert Harris, Vol. 32, No. 11/12, November/December 1982, pg. 67.

Forest Fuels has concentrated on this market--the user of from 40,000 to 800,000 gallons of oil per year. Others have concentrated on the larger users--the heavy industries.

Let me illustrate with two typical applications of our systems in some detail, setting forth the energy use, the cost of the system, the economics, and the results, and then we can open this up for questions.

CASE ONE: A customer of ours in a southeastern state installed a Forest Fuels gasifier in his hardwood kiln and planing operation in 1978. Planing produces the fuel-- 2-3,000 tons of dry hardwood shavings a year, which replaces roughly 46 billion Btu/year--7,000 hours-- an annual savings of $105,000 in 1978. The savings are presently on the order of $180-200,000 per year in fuel savings. The system cost $200,000 in 1978--including a $120,000 200 HP Cleaver-Brooks 4-pass boiler. Annual costs of maintenance and labor are roughly $17,000 per year. The system has run for 7,000 hours a year for 5 years. Needless to say, such a system gives this kiln operator a real business edge over other kilns operating on oil or natural gas. Boiler performance is said to be up to expected capacities of the boiler, with no de-rating noticed. There is no tube erosion, and the tube cleaning may increase from one to two times per year.

CASE TWO: A New England lumber kiln operator, who buys pulp-grade chips for fuel @ $15 per ton, replaced $78,000 worth of #2 oil in 12 months--March '81 - March '82--with $18,000 worth of chips and $3,000 worth of electricity to run the motors (a total of 14 HP) connected with the system. The capital cost of the system was $147,000. Annualized capital cost is $26,000. So the net saving on this system is, roughly, $40,000 per year. Presently, the capacity of the system is underutilized by at least 50%. If a new kiln is installed, fuel savings will be double, and a far greater return on investment will be realized. The boiler used here is a 125 HP York-Shipley 3-pass boiler. The boiler tubes are cleaned twice a year. There are no polluting emissions from this system, and Massachusetts Air Quality Agency cites this unit in its state book of standards as a model for wood combustion.

To date, we have retrofitted 5 Cleaver-Brooks package boilers from 40-200 HP, 1 York-Shipley package boiler, 1 Dillon HRT, 2 Superior 4-pass 250 HP, and 1 Titusville.

Forest Fuels recognized the boiler retrofit market opportunity for gasifiers in 1975 and has been developing and demonstrating a technology that is allowing energy users to convert from oil and gas to wood with relatively simple, cost effective equipment. It is significant that, in 1981, when SERI did the North American gasifier study, of the 14 gasifier sites actually visited, 7 were Forest Fuels' systems. All of the sites were commercial operations, where the economics of wood fuel were at work over months and years of operation. The impression is generated among energy gurus that gasification is a new and unproven, and therefore, possibly unreliable technology as applied to boiler retrofits. This may have been true in 1977, but it is no longer true.

Of course, during our development period, there has been a learning curve connected with gasification and boiler retrofits. But there has been steady progress and some very solid achievement. The Forest Fuels gasifier retrofits cited in the 1981 SERI survey have at this time collectively logged almost 30 years of commercial operation. We have added a number of other commercial sites since the SERI study. Also, a Forest Fuels dryer used with two modified hog-fuel boilers has operated in a large greenhouse for four years.

Before going on, a brief review of the combustion process that occurs in the Forest Fuels gasifier is in order. (Refer to Figures 1, 2 and 3.)

Our current models are simple, safe, and very competitive with other wood energy systems, and they have proven to be effective. The State of New Hampshire Air Quality Commission recently granted an operating permit for one of our systems, with a 5 rating on the opacity test. Zero is perfect, 40 is passing. The system is clean environmentally.

We do <u>not</u> feel that the operator need be a graduate engineer to understand how to run the equipment. The control system permits automatic operation, meeting changing load requirements. An average of less than one hour of attendance through a 24-hour period is standard for our clients.

Wood is not as easily managed as pipeline gas or oil, however. So it is fair to say that there are likely to be problems, mainly in fuel delivery. The success of a gasifier, or any wood energy system, is directly proportional to the interest, particularly the economic interest, of the owner and the operator of the system to see that the system works and a major fuel saving is realized over extended time periods. We have seen systems shake down and run for 2-3 years without major interruption, save for a day or so routine maintenance. We have also seen duplicate systems, however, in a public works setting, or a remote corporate corner, which have made Murphy and his law seem positively optimistic.

We have been honest, faced the technical problems, and solved them. We believe that we have done this, and we

TOTAL SYSTEM DESCRIPTION

WOOD + AIR – $HEAT_G$

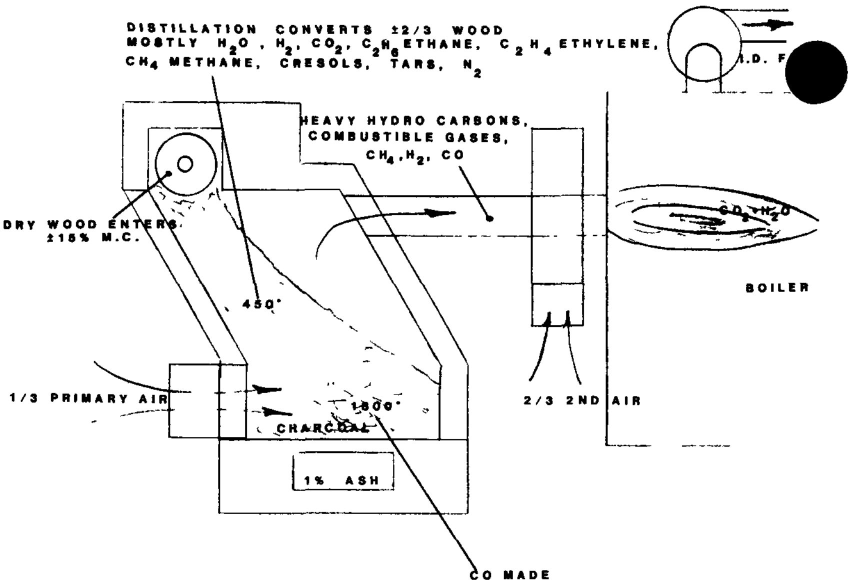
$HEAT_G$ – H_2O LOSS – EXHAUST LOSS – $HEAT_N$ INTO WORK

DRYING

PROCESS

FIGURE 1

BASIC WOOD GASIFICATION



MAJOR REACTIONS IN GASIFIER

$$C + O_2 - CO_2 + HEAT$$

$$C + CO_2 + HEAT - 2CO$$

$$2C + O_2 - 2CO + HEAT$$

$$C + 2H_2 - CH_4$$

FIGURE 2

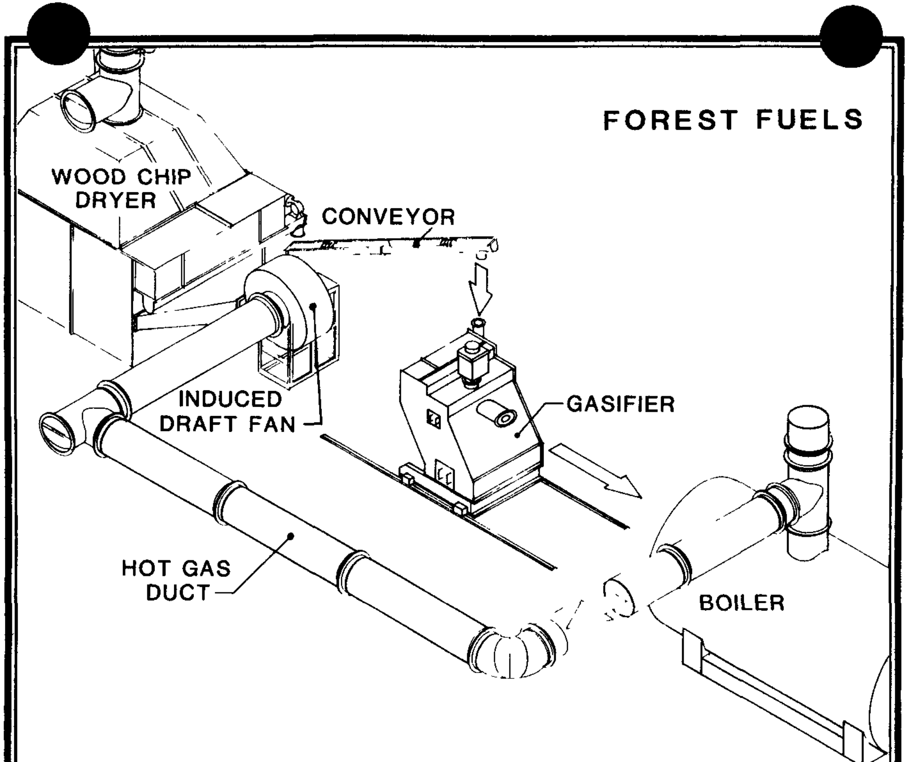

FOREST FUELS
WOOD CHIP
DRYER
CONVEYOR
INDUCED
DRAFT FAN
GASIFIER
HOT GAS
DUCT
BOILER

FIGURE 3

believe we have a product which, properly placed, is a credit to us and a real asset to our customers. Our record now bears this out, and we invite all energy users to investigate us in person, visit our plant and our installations in New England, New York, Carolina, or Georgia.

We have gained enough experience in a demanding business to know very quickly whether a wood/gas system belongs in front of a boiler or if it does not. We firmly believe that there are many boilers operating now throughout the country and beyond that can be set up to run on wood gas to the profit of the owners and the benefit of the local and national economies. We are eager to make this technology available to energy users.

Dup

WASTEWATER RECLAMATION AND METHANE PRODUCTION USING WATER HYACINTH AND ANAEROBIC DIGESTION

D. P. Chynoweth
D. A. Dolenc
B. Schwegler
K. R. Reddy

INTRODUCTION

This paper describes the results of research in progress to evaluate the technical and economic feasibility of utilizing water hyacinth ponds for treatment of domestic wastewater and the utilization of anaerobic digestion for conversion of the hyacinth crop and primary sludge to methane. The system concept illustrated in Figure 1 employs water hyacinth ponds for secondary and tertiary treatment of effluent from primary treatment (which removes settleable solids). Primary effluent supernatant is passed through water

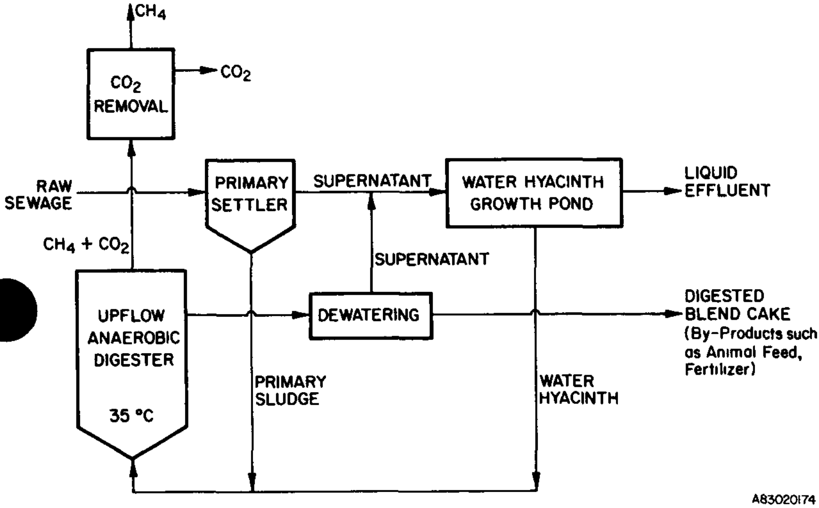


Figure 1. SCHEMATIC DIAGRAM OF INTEGRATED HYACINTH WASTEWATER TREATMENT AND BIOGASIFICATION SYSTEM

hyacinth ponds which effect organic and nutrient reduction. Collected primary sludge and harvested hyacinth are added as a blend to the anaerobic digestion process where a portion of the organic matter is converted to methane and carbon dioxide. The methane is separated from the carbon dioxide and used as an energy product. Digester residue solids may be posttreated to improve biodegradability and recycled to the digester or used for land fertilization along with the digester supernatant.

This biomass waste treatment energy conversion scheme has served as a basis for the following overall program objectives:

1. To determine the feasibility of using water hyacinth to treat sewage to secondary and tertiary standards
2. To maximize hyacinth growth yields while maintaining effective wastewater treatment
3. To determine the feasibility of integrating a biogasification process with the hyacinth treatment scheme for conversion of the primary sludge and hyacinth to methane.

The project is centered around the main growth and conversion facility located at Walt Disney World (WDW), Orlando, Florida, and currently involves several participants including the University of Florida, Institute of Gas Technology (IGT), and several subsidiary companies of Walt Disney Productions. The current sponsor is the Gas Research Institute (GRI). Previous sponsors included the Environmental Protection Agency and the U.S. Department of Energy.

WASTEWATER TREATMENT

Hyacinth wastewater treatment studies were conducted in five channels 8.8 m x 110 m x 0.35 m deep, constructed of reinforced concrete blocks and lined with 20-mil PVC sheet. The ponds were generally operated in parallel on either primary or secondary effluent from the Reedy Creek Wastewater Treatment Plant. The retention time ranged from 3.6 to 5.3 days. Measurements of influent and effluent included flow, temperature, pH, total solids, suspended solids, biochemical oxygen demand (BOD), and various forms of nitrogen and phosphorus. In general, sections of each pond were harvested approximately twice a month. A more detailed description of methods and results of this study were presented previously.(1)

The mechanisms for treatment of wastes by water hyacinth generally are applicable for aquatic macrophytes and include the following: sedimentation, bacterial carbon metabolism, bacterial nitrogen removal, adsorption, and precipitation. Particulate matter in the influent or formed within the pond (bacterial cells and precipitates) settles in the pond and periodically must be removed as sludge. Influent carbon is metabolized by bacteria which are either attached to the plant root system or suspended in the liquid stream. Nitrogen may be transformed from one form to another by bacterial activity and some nitrogen is lost as N_2 formed by denitrification. Heavy metals, toxic organics, and other compounds may be absorbed to the plant roots and physically removed with the plants during harvest. Various inorganic nutrients are adsorbed into the plants and serve as growth factors for stimulation of hyacinth growth. Pollutants such as heavy metals and phosphates may be removed by precipitation. These mechanisms act in concert to purify the wastewater as it passes through the ponds. The nutrients not only are removed, but stimulate growth of the hyacinth plants.

Table I shows mean annual reduction in suspended solids, BOD, nitrogen, and phosphorus. Seasonal fluctuations observed in the removal efficiencies of these parameters could be directly related to growth of the hyacinth. For example, during the winter months (January and February) both hyacinth growth and pollutant removal were the lowest. Nevertheless, removal efficiencies for these parameters usually met the requirements for wastewater treatment in the State of Florida throughout the year. Hyacinth ponds operated at a retention time of 4.3 days or longer appear to result in effective secondary wastewater treatment. Studies on tertiary treatment are currently in progress.

WATER HYACINTH GROWTH YIELDS

Maximum growth yields of hyacinth are desirable because rapid growth will be associated with efficient waste treatment and result in larger quantities of biomass available for conversion to methane. Numerous variables can influence hyacinth yields, the most important of which are temperature, amount of sunlight, concentration of CO_2, nutrient availability, planting density (or harvest rate), and pestilence. Of these, the controllable parameters studied thus far included nutrient availability (via retention time of wastewater) and planting density. Other observations were made on the effect of uncontrolled variables such as temperature and attack by insects.

Table I. WASTE TREATMENT EFFICIENCIES OF WATER HYACINTH PONDS RECEIVING PRIMARY EFFLUENT

Parameter	Percent Reduction: Mean Annual	Percent Reduction: Range
Suspended Solids	86	77-96
BOD	85	65-95
	Mean	Range
N Uptake, mg N/m^3-day	473	305-734
P Uptake, mg P/m^2-day	106	72-157

Biomass production in each channel was determined using 1 m^2 Vexar mesh baskets (six baskets per channel) placed about 18.3 m apart in each channel. In general, a starting plant density of 13.6 kg wet wt/m^2 was used in each basket. At the end of each week, the baskets were removed and allowed to drain for 5 minutes, and the wet weight determined. Plant density in each basket was adjusted to the original density by harvesting excess plants. The methods and results of this work are described in more detail elsewhere.(1,2)

Figure 2 shows seasonal variation of water hyacinth yields in ponds with three different retention times. Higher yields were observed in ponds with longer retention times. This probably reflects increased availability of nutrients. Channels 1 and 2 exhibited an average hyacinth yield of 54 dry

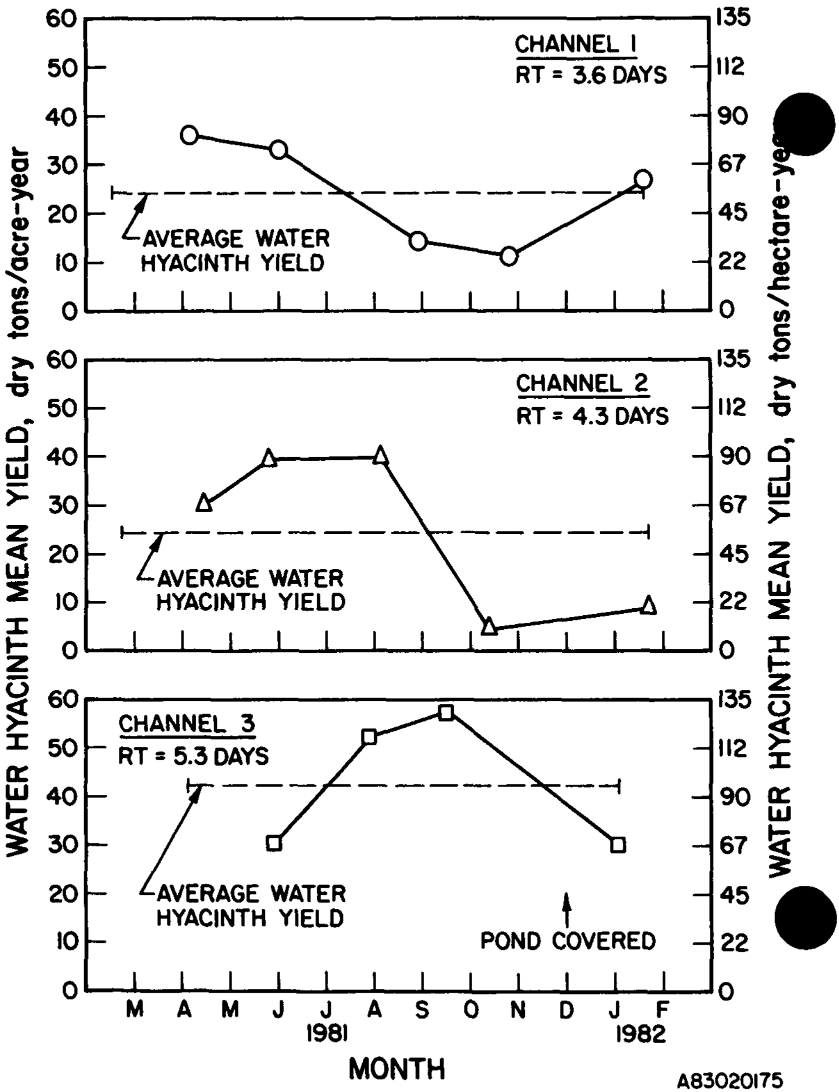


Figure 2. SEASONAL VARIATION IN HYACINTH YIELDS AT DIFFERENT RETENTION TIMES

tons/ha-yr. Yields were generally lower during the colder months, reflecting the direct effect of lower temperature and less sunlight on hyacinth yields. In one channel, which was covered with a translucent plastic cover, the yields during the winter months were about 40% higher than in the uncovered channels. This can be attributed to higher temperatures in the covered channel and protection of the plants from frost. It was noted that periodic infestation of the moth (Sameodes), weavel (Neochetria), and spider mite (Bryobia) resulted in lower hyacinth yields. Table 2 shows that the mean yield in the channel used for secondary treatment was significantly higher than that in the channel used primary treatment. This difference is probably related to the lower availability of nutrients in the tertiary channel.

TABLE 2. HYACINTH GROWTH YIELDS (MAY-OCTOBER) IN PRIMARY VERSUS SECONDARY EFFLUENT

Growth Medium	Yield, tons dry wt/ha-yr Mean	Range
Primary Effluent	60	18-117
Secondary Effluent	48	14-69

Results of experiments conducted to determine the relationship between planting density and hyacinth yield show that the maximum yield was obtained at a density of about 36 kg/m2. Future research on hyacinth growth will 1) determine optimum retention time and water depth; 2) identify potential nutrient limitations; 3) relate optimum planting density to harvest rate; and 4) establish more data on tertiary treatment.

ANAEROBIC DIGESTION PROCESS DEVELOPMENT

Anaerobic digestion was selected as the process for energy conversion of the primary sludge and water hyacinth since it produces methane as the principal product and the process is suitable for feedstocks with a high water content. The objective of this part of the study was to develop a data base for the design and operation of an optimized system for biogasification of the hyacinth and sludge and to integrate this process with the hyacinth wastewater reclamation facility. It is expected that the process design developed will be applicable to other aquatic species with high water contents. The strategy followed is outlined below:

- Collection and analysis of feeds
- Determination of anaerobic biogasification potential of feeds
- Determination of biogasification characteristics of feeds under baseline conventional anaerobic digestion
- Evaluation of potential nutrient requirements
- Evaluation of effect of blending feeds on digester performance
- Kinetic analysis of anaerobic digestion of test feeds

- Design and construction of experimental test unit (ETU) suitable for evaluation of materials handling and process scale-up

- Systems analyses.

Feedstocks

Large batches of primary sludge and water hyacinth were collected from the WDW wastewater treatment plant, milled to reduce particle size, and frozen until analysis or use in bench-scale digestion studies. Proximate and ultimate analyses (standard procedures presented elsewhere)(3) were conducted on these feeds for the purpose of determining digester loadings, predicting potential nutrient requirements, and calculation of theoretical yields. The physical and chemical characteristics of both feeds are shown in Table 1. Both feeds have high water and low ash contents. The heating value for hyacinth is in the range normally observed for herbaceous biomass, 17.4 MJ/kg; however, the primary sludge had an exceedingly high heating value of 26.5 MJ/kg. Nitrogen and phosphorus levels (Table 1) exceeded those normally considered to be limiting for anaerobic digestion. The heating value data indicate that this water hyacinth had a methane yield potential in the range normally observed for biomass; however, the primary sludge far exceeds normal levels. The anaerobic biogasification potential determined by long-term batch assays was 0.62 and 0.35 L/g VS added for sludge and hyacinth, respectively, corresponding to reductions in organic matter of 80% and 60%. These represent maximum conversion to be expected without pretreatment.

Table 3. PHYSICAL AND CHEMICAL CHARACTERISTICS OF DIGESTER FEEDS COLLECTED FROM WALT DISNEY WORLD

Chemical Characteristics	WDW Primary Sludge	WDW Water Hyacinth
Solids Content		
Total Solids (TS), wt %	2.99	4.78
Volatile Solids, wt % of TS	93.10	86.07
Heating Value, MJ/kg	17.4	26.5
Nutrient Ratios		
C:N	16:1	11:1
C:P	95:1	52:1

Conventional Anaerobic Digestion

Several experiments were conducted to evaluate the performance of hyacinth and sludge and blends of these feeds under conditions of conventional anaerobic digestion. The results provide a data base that can be compared to that obtained in this and other laboratories on various feedstocks. These experiments were conducted in 5-L daily-fed digesters operated at 35°C, a loading of 1.6 g VS/L-day, and a retention time of 15 days. Performance data summarized in Table 4 show that methane yields of 0.19, 0.52, and 0.28 L/g VS added were obtained for hyacinth, sludge, and a 3:1 blend* (dry solids basis) of hyacinth and sludge. These yields correspond to 54% and 84% of the ultimate biodegradable yields for hyacinth and sludge as determined by the ABP assay. All three digesters exhibited stable performance with low concentrations of volatile fatty acids and no requirement for pH control. The methane yield for water hyacinth alone was comparable to that observed in other work on water hyacinth.(4,5) The moderate yield for hyacinth suggests the need for a long residence time and/or pretreatment to increase the biodegradability and associated methane yield.

Table 4. MEAN GAS PRODUCTION DATA DURING STEADY-STATE OPERATION OF MESOPHILIC (35°C) DIGESTION RUNS CONDUCTED AT A LOADING OF 1.6 g VS/L-day AND A RETENTION TIME OF 15 DAYS

Run No.	Feed	Total Gas Production Rate, Std L/L culture-day	mol %	Methane Yield, L/g VS added
801	Water Hyacinth	0.517	58.8	0.19
803	Hyacinth/Sludge	0.701	63.2	0.28
804	Primary Sludge	1.25	69.2	0.52

*The hyacinth/sludge blend contained 75 wt % water hyacinth and 25 wt % primary sludge (on a dry solids basis).

The above experiments were repeated in the presence of excess nitrogen and phosphorus to determine if either of these nutrients was limiting. Such a limitation might play a role in determining optimum blend ratios of nutrient-rich and nutrient-deficient feeds. For example, in a study we conducted previously,(6) Bermuda grass was deficient in nitrogen. This deficiency was overcome by blending with nutrient-rich feeds such as sewage sludge. The data for hyacinth and sludge indicate that addition of nitrogen and phosphorus to digesters receiving hyacinth or sludge did not improve digester performance, suggesting that these nutrients were not limiting. Thus, blends for these feeds can be determined on the basis of factors other than nutrient requirements.

A hyacinth/sludge blend of 3:1 was used in the above baseline digestion studies, which corresponds to a hyacinth yield of 90 dry metric tons/ha-yr. Although the sludge production rate is expected to remain relatively constant for a specific pond area (2.15 dry tons/ha-day), the hyacinth yield will vary depending upon growth conditions. The objective of this experiment was to evaluate the performance of two additional blends, 5:1 and 1:1, corresponding to hyacinth yields of 157 and 34 dry metric tons/ha-yr, respectively. The results of these experiments show that methane yields from blends can be predicted from the fractional content and methane yield of each component of the blend according to the following formula:

*Corresponds to a hyacinth growth yield of 90 dry metric tons/ha-yr.

$$Y_{BLEND} = (Y_{HYAC})(\text{HYACINTH VS * FRACTION}) + (Y_{SLUDGE})(\text{SLUDGE VS * FRACTION})$$

Several digester experiments were conducted to evaluate the digester performance on hyacinth, sludge, and a hyacinth/sludge blend at several different loading rates. The results described in detail elsewhere (3) indicated that digestion of these feeds adhered to the Monod kinetic model which was modified to predict methane yield and production rate as a function of organic loading for a stirred tank reactor. A plot of these relationships shown in Figure 3, shows that maximum methane yields are achieved at lower loadings (longer retention times) and that the loadings giving maximum rate and yield do not correspond. These results may be attributed to the fact that at high loadings, active bacteria and unreacted particulate solids wash out due to the high water content of both feeds.

Unconventional Advanced Digestion

On the basis of the above results with conventional stirred tank reactors (STR), digestion of hyacinth/sludge blend was investigated in two two reactor designs designed to increase solids and microorganism retention. In one, the stirred tank reactor with solids recycle (STR/SR), particulate solids were separated and a portion (about 30%) recycled back to the stirred tank reactor. In another, the upflow solids reactor (USR), the feed was added to the bottom of a nonmixed reactor and solids and liquid removed from the top on a semicontinuous basis (once per day). Sedimentation of particulate matter within this reactor results in a longer solids than liquid retention time.

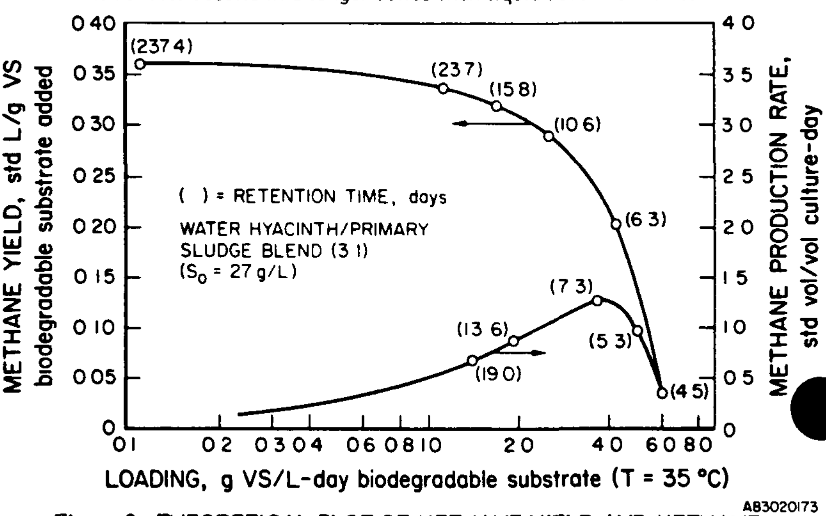


Figure 3. THEORETICAL PLOT OF METHANE YIELD AND METHANE PRODUCTION RATE VERSUS BIODEGRADABLE ORGANIC LOADING FOR 3:1 (dry wt) WATER HYACINTH/SLUDGE BLEND

*Volatile solids (ash-free dry wt).

Although these studies are still in progress, data in Table 5 show that at three different loadings both unconventional digesters exhibited similar methane yields which were significantly higher than those of the conventional STR digester. At this point, we favor the upflow solids digester because of its lower capital and operating costs and lower energy requirements.

Table 5. COMPARISON OF METHANE YIELDS FROM 3:1 HYACINTH/SLUDGE BLEND IN STR, STR/SR, AND USR DIGESTERS (35°C)

	Methane Yield, L/g VS added		
Loading, g VS/L-day	1.6	1.9	0.24
Stirred Tank Reactor(STR)	0.28	0.24	0.24
Stirred Tank Reactor/Solids Recycle (STR/SR)	0.34	0.34	0.29
Upflow Solids Reactor (USR)	0.35	0.33	0.28

Design and Construction of Experimental Test Unit

It is the consensus of participating parties that process development information compiled thus far from bench-scale experiments should be confirmed and augmented by data that can only be obtained in a larger ETU system before a final process configuration can evolve. The objective of this task is, therefore, to design, construct, and operate an ETU. The conversion system will have a high degree of flexibility and will include front-end biomass processing and slurry preparation equipment, one or more digestion units (to accommodate single or multistage operation), digester effluent processing equipment, and gas clean-up equipment. Past bench-scale data and concurrent support studies will narrow the options for design and operation of the ETU. The primary function of this unit will be to validate baseline digester operation and performance data obtained in the bench-scale tests and to evaluate larger scale equipment for chopping, slurry preparation, mixing, pre- and posttreatment, and dewatering. This unit will also provide sufficient effluent for evaluation of its potential animal feed and fertilizer value. The results from the ETU studies will provide a basis for a complete conceptual process design and cost estimate of a larger conversion system.

IGT is currently procuring equipment for this system which is scheduled for installation during 1983. The front end consists of hyacinth and sludge grinders, holding tanks, and a mixed feed holding tank. The digester system will initially have one reactor, a continuous stirred reactor which can be operated as an STR or USR. The digester system will be semicontinuous (24 times a day) feed, and equipped for on-line monitoring of critical operation parameters. The unit is currently being sized at a total reactor volume of 4.5 m^3 on the basis of receiving sludge and hyacinth associated with operation of three ponds. Future plans include addition of a second attached film digester, a pre-/posttreatment unit, dewatering equipment, and a computerized automated process analysis and control system. Addition and operation of these additional units will depend on results of laboratory experiments in progress.

CONCLUSIONS

Research reported here supports the conclusion that water hyacinth ponds are effective in the secondary treatment of domestic wastewater and under these conditions exhibited an average growth yield of 60 dry tons/ha-yr. However, treatment efficiencies and growth yields vary significantly in response to factors which include 1) levels of nutrients in the pond influent; 2) residence times and water depth; 3) cultural techniques such as plant density and harvest frequency; 4) environmental conditions such as temperature, frost, etc.; and 5) insect infestation. These variables are under more intense study using smaller scale experiments. The results of these studies wil be employed to determine optimum conditions for operation of the larger ponds.

Work thus far completed on the anaerobic digestion of hyacinth and sludge has provided information on feed properties, feed biodegradabilities, digestion efficiencies under conventional digestion, nutritional balance, and the effects of blend constituents on methane yield and production rate. It is known that these feeds can be digested without external nutrient addition or pH control. The kinetics and efficiencies are comparable to those of other biomass or waste feeds; in fact, the yield from primary sludge is the highest we have seen reported for particulate feeds. Two unconventional digester designs are currently exhibiting a significant increase in feed conversion to methane. Future laboratory research will continue to focus on advanced digestion and pretreatment for improvement of conversion efficiencies and net energy production. This will be complemented by operation of a larger scale experimental test unit.

The results of the hyacinth growth and anaerobic digestion research are closely coordinated and the data are being utilized for systems and economic analysis of the total integrated waste reclamation energy conversion system.

ACKNOWLEDGMENTS

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METHANE RECOVERY FROM SANITARY LANDFILLS

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INTRODUCTION

Current estimates place the amount of energy escaping from landfills in the United States in the form of combustible gases at 1 to 2 x 10^{15} Btu annually. Using existing technology, approximately 0.4 x 10^{15} Btu per year of this gas can be economically recovered. Although this is less than one percent of the nation's annual energy consumption, utilization of this alternative energy source is nevertheless economically feasible.

The recovery, processing, and utilization of combustible gases generated in sanitary landfills can be a cost-effective method of developing an environmentally acceptable alternative energy source. Safety issues include the reduction of landfill explosive hazards, operational equipment and consumer protection. This paper reviews the landfill gas recovery industry and the activities needed to proceed through a landfill gas utilization program.

RESOURCE BASE

There are approximately 30,000 landfills in the United States. One half of these landfills are no longer receiving waste (i.e. closed). The remaining active landfills are broken down by approximate size in Table 1.

TABLE 1

ACTIVE LANDFILLS IN USA

Size in Millions of Tons	Number	Total Tonnage in Millions of Tons
Greater than 2	320	1600
1-2	650	950
0.5-1.0	1000	750
Less than 0.5	13600	3400
T O T A L	15570	6700

LANDFILL GAS RECOVERY

In the landfill, anaerobic digestion converts the organic materials in the waste, to methane (CH_4) and carbon dioxide (CO_2). This gas is collected through a system of landfill gas recovery wells. A typical well consists of a 3 to 8 in. diameter pipe, with the lower section perforated and inserted into a 12 to 36 in. hole. The hole is backfilled with gravel and sealed at the top with concrete or clay. The individual wells are connected to a blower/compressor that delivers the gas to a central area for "clean up" or processing.

Landfill gas normally has a methane content of 40 to 55% with a heating value of approximately 500 Btu per standard cubic foot (scf). Other major constituents are carbon dioxide (40 to 50%), nitrogen (1-5%) and oxygen (1-5%).

At most existing recovery sites, the raw landfill gas is collected, the moisture and particulates are removed, and the gas is compressed and cooled. For use in space heating, as a boiler fuel, and for process heat (medium-Btu gas applications) the gas can be burned with little or minimal treatment. A high-Btu product, equivalent to natural gas, can be produced by removing the carbon dioxide. Although this process is complex, several plants currently are processing landfill gas and injecting the "refined" landfill gas directly into natural gas distribution systems where it is mixed with natural gas.

ON-LINE FACILITIES

The process of recovering and utilizing landfill gas began in 1975 at the Palos Verdes landfill in suburban Los Angeles, California. In 1979 there were ten facilities on-line producing 1.6×10^{12} Btu annually. During 1982 the fourteen on-line facilities produced 3.7×10^{12} Btu. Table 2 indicates the on-line facilities as of January 1983.

Palos Verdes Landfill, Rolling Hills Estates, California

After carbon dioxide and other trace contaminants are removed and the gas has been dehydrated and compressed, it is sold to Southern California Gas Company. The eight wells average 150 ft. in depth and collect 1.5 x 10^6 $ft.^3$ of landfill gas a day.

Southwest Portland Cement Landfill, Azusa, California

Seventeen wells 90 to 100 ft. deep, collect 0.7 million cubic ft. of landfill gas per day. After the moisture is removed, this gas is sold to Reichold Chemical Company, approximately 0.5 miles away.

Mountain View Landfill, Mountain View, California

This facility, currently delivering 0.5 x 10^6 $ft.^3$ of landfill gas per day - is producing treated gas at approximately 800 Btu/scf that is injected into Pacific Gas and Electric's distribution grid.

ASCON Landfill, Wilmington, California

Sixty wells, 40 to 55 ft. deep, collect 1.3 x 10^6 $ft.^3$ of 530 Btu/scf landfill gas daily. This gas is sold to a nearby Shell oil refinery.

Industry Hills Landfill, City of Industry, California

This project supplies a portion of the energy required at the Industry Hills Convention Center. The facility includes two 18-hole golf courses, a clubhouse, exhibit center, pool, and tennis complex. Landfill gas, as much as 0.6 x 10^6 per day, is collected from 30 wells that are up to 70 ft. deep.

Operating Industries Landfill, Monterey Park, California

Pipeline-quality gas is delivered to Southern California Gas Company's distribution system. Fifty-one wells, half of which recover gas from upper landfill layers, while the other half recovers gas from sections more than 250 ft. deep, have the capacity to collect 8 x 10^6 $ft.^3$ of landfill gas per day.

Cinnaminson Landfill, Cinnaminson, New Jersey

Thirty wells about 50 ft. deep collect nearly 0.3 x 10^6 $ft.^3$ per day of gas that is sold to Hoeganaes steel plant approximately 0.5 miles away. The landfill gas is pumped from the wells, compressed, passed through wood shavings permeated with iron dioxide from sulfide removal, cooled and then delivered to the plant at about 600 Btu/scf.

Sheldon Arleta Landfill, Los Angeles, California

The 14 recovery wells at Sheldon Arleta Landfill are 80 to 100 ft. deep and provide 1.5 x 10^6 $ft.^3$ of landfill gas daily. The gas is piped to a power plant where it is used as a supplementary fuel used in the generation of electricity.

<u>Bradley Landfill, Los Angeles, California</u>

The 39 wells spaced out over the 67-acre site collect over 2 million cubic feet of landfill gas daily. After water knockout, the gas is delivered to the Valley Steam plant for use as starter and boiler fuel.

<u>CID Landfill, Calumet City, Illinois</u>

Pipeline-quality gas is deliverd to Natural Gas Pipeline Company of America for distribution. Fourteen wells will collect a maximum of 5×10^6 ft.^{3} of landfill gas per day. Currently, 1.5×10^6 ft.^{3} of gas is delivered daily.

<u>Davis Street Landfill, San Leandro, California</u>

The landfill gas is collected from wells 75 ft. deep, impurities and moisture are removed and over two million cubic feet per day is delivered at 550 Btu/scf to Domtar Gypsum which is about two miles from the landfill.

<u>North Valley Landfill, Sylmar, California</u>

This 42-acre landfill (over 250 ft. deep) provides in excess of one million cubic feet of landfill gas daily to the Newhall refinery for use as a boiler fuel.

<u>Acme Landfill, Martinez, California</u>

The 80 ft. deep, 125-acre landfill has the capacity to deliver up to 2.5 million cubic feet per day of 500 Btu/scf gas to the Contra Costa Sanitation District.

<u>Fresh Kills Landfill, Staten Island, New York</u>

This operation at the largest landfill (10,000 tons/day) has the capability of delivering up to 5 million CFD to Brooklyn Union Gas' distribution system.

TABLE 2

ON-LINE LANDFILL GAS FACILITIES

Landfill	BTU/SCF	Gas Provided Daily to Energy Users in Millions of Cubic Feet
Palos Verdes, CA	1000	0.7
Azusa, CA	550	0.7
Mt. View, CA	800	0.5
ASCON, Wilmington, CA	530	1.3
City of Industry, CA	500	0.6
Monterey Park, CA	1000	1.0
Cinnaminson, NJ	600	0.3
Sheldon Arleta, LA, CA	500	1.5
Bradley, LA, CA	500	2.0
CID, Chicago, IL	1000	1.5
San Leandro, CA	550	2.0
North Valley, Sylmar, CA	500	0.5
Martinez, CA	500	0.5
Fresh Kills, New York, NY	1000	2.5

PROCEDURES FOR DEVELOPING LFG UTILIZATION SYSTEMS

GENERAL

The purpose of this section of the paper is to describe the steps to be taken by a landfill owner/operator in the development of a landfill gas (LFG) utilization program. As will subsequently be described in more detail, there are essentially six steps in a development program, which are as follows:

- Phase I - Preliminary Analysis
- Phase II - Detailed Feasibility Determination
- Phase III - Design
- Phase IV - Construction
- Phase V - Start-Up and Fine-Tuning
- Phase VI - Operation

The time frames required to execute each of these phases have been detailed in Table 3. Though exceptions

TABLE 3

PHASED DEVELOPMENT PROGRAM SCHEDULE

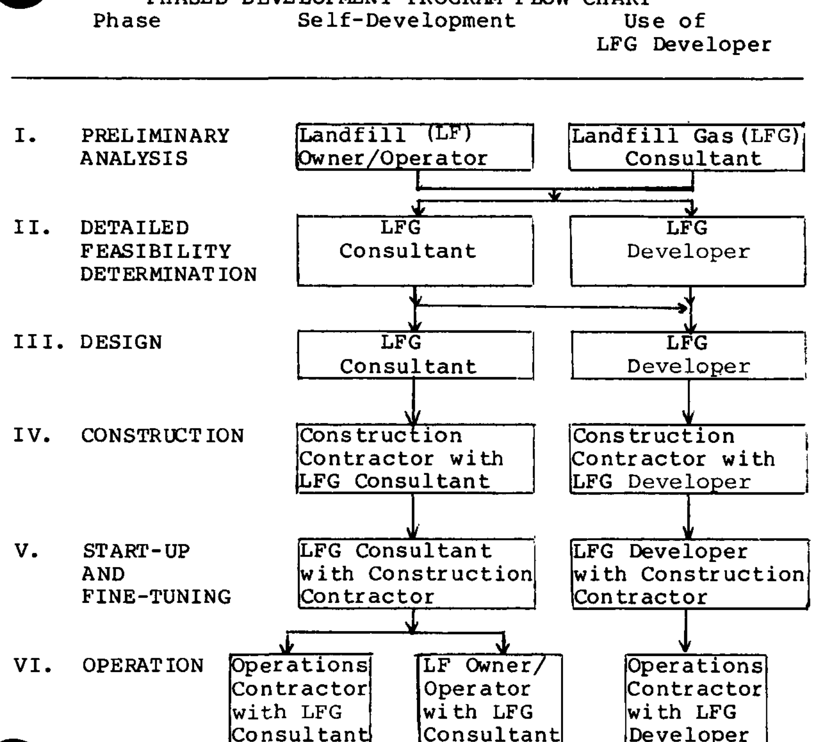
	Phase	Time Required
I.	Preliminary Analysis	2 - 6 months
II.	Detailed Feasibility Determination	6 - 12 months
III.	Design	6 months
IV.	Construction	6 months
V.	Start-Up and Fine-Tuning	2 - 6 months
VI.	Operation	$\geq$10 years

exist to the time frames indicated, experience in developing landfill gas utilization sites has indicated that a total lead time from two to three years is required from the preliminary analysis until onset of operations. It should be recognized that this schedule may be accelerated under certain circumstances. However, many of the considerations which must be addressed in the development of landfill gas utilization facilities are beyond the control of the landfill owner/operator, and include such items as regulatory review, coordination with utilities, etc.

In developing a landfill gas utilization system, there are essentially two routes which can be taken: (1) self-development, or (2) use of an outside landfill gas developer. A flow chart to describe the phased development program under each of these scenarios has been included as Table 4.

TABLE 4

PHASED DEVELOPMENT PROGRAM FLOW CHART



The parties of interest in a landfill gas development program include generally:

1. The landfill owner/operator (through use of in-house personnel)
2. A landfill gas consultant
3. A landfill gas developer (with experience and success in developing gas utilization facilities, and paying royalties to landfill owner/operators)
4. Construction contractors, and
5. Operations contractors.

In a self-development program, the preliminary analysis phase can be executed either by in-house personnel with the landfill owner/operator, or by an outside landfill gas consultant. The essential steps under such a preliminary analysis are described in detail later in this paper. Regardless of whether it is a foregone conclusion that a landfill gas developer will be called in, this preliminary analysis stage should be performed by someone other than the developer himself.

Upon completion of the preliminary analysis stage, a determination should be made to proceed with self-development or to use a landfill gas developer. In a self-development scenario, a landfill gas consultant is typically called in. This consultant, and subsequent construction and operation contractors, then perform the activities required to proceed through operation. Overall direction and management is provided by the landfill owner/operator himself.

If a landfill gas developer is selected at this juncture, typically a royalty agreement is executed between the landfill owner/operator and the developer. Under a royalty agreement, a percentage of the gross revenues for sale of the landfill gas acquired by the developer are paid to the landfill owner/operator. Design, construction, and operation are fully the responsibility of the LFG developer. The landfill owner/operator is required only to make his landfill available and accessible to the developer. It should be noted that developers will not typically ensure landfill gas control, which may be a primary concern to the landfill owner/operator.

PRELIMINARY ANALYSIS

As described previously, a preliminary analysis should be performed in any event, even if the landfill owner/operator assumes that a developer would be brought in. A preliminary analysis can be performed either by in-house personnel, or through the use of an outside landfill gas consultant.

Under either condition, there are a number of items which need to be addressed under a preliminary analysis as detailed below:

- Task I-1 - Estimate LFG Recovery Potential
- Task I-2 - First-Cut Costs vs Revenues
- Task I-3 - Identify Potential Markets
- Task I-4 - Investigate Other Considerations
- Task I-5 - Delineate Future Program

The balance of this section will describe the steps to be taken under each of the aforedescribed tasks.

Estimate LFG Recovery Potential

During this step, various characteristics of the landfill (under existing and proposed future conditions) are investigated to determine the total potential recoverable gas quantity. Over the years, selected "minimum criteria" have been established as a first cut assessment of suitability for gas utilization facilities. These are summarized below:

- Minimum of 2,000,000 tons of in-place refuse
- Minimum of 150 to 400 tons/day waste receipt rate
- Minimum 40 ft. depth over recoverable areas of landfill
- Minimum size of 40 acres
- Minimum of 2 years remaining life

It should be emphasized that exceptions to the above minimum criteria do exist. However, it is only through the conduct of detailed pumping test programs (Phase II) that it can be assumed that sufficient revenues will be gained from gas sales to make such systems feasible.

First-Cut Costs vs Revenues

As was described earlier in this paper, there exist essentially three alternatives for gas utilization:

- Medium Btu - This entails extraction, sale, and the use of the gas in an essentially "as-is" condition. Cleanup consists of nominal particulate and moisture removal. Other impurities (chiefly carbon dioxide) are not removed. The product gas is a "medium-Btu" fuel, with a heating value of approximately 500 Btu/cu. ft.

- High-Btu - Under certain circumstances, patented processes are available to remove the impurities typically found in landfill gas. This includes chiefly removal of carbon dioxide to improve the Btu content of the fuel extracted. Fuel values of "high-Btu" purified landfill gas run from 900 to 1,000 Btu/cu. ft.

- Electrical Generation - This entails combustion of medium-Btu landfill gases in on-site internal combustion engines or turbines. The product electricity is typically sold to a local utility. This application has received a large incentive in the form of the Public Utilities Regulatory Policy Act (PURPA). Under the tenets of PURPA, utilities are required to purchase electricity from small generators at an often favorable price known as the "avoided cost". In some market areas, avoided costs are in excess of the going commercial rate, at from $0.04 to $0.10 per kilowatt hour.

Upon completion of the first task above, a determination can be made of likely LFG revenues by applying rules-of-thumb. Selected rules-of-thumb are summarized below:

- Typical landfill density = 800 lb./cu. yd.
- Total LFG generation = from 0.08 to 0.28 cu. ft./lb./yr.
- Collection capability typically about 50% of generation, or 0.04 cu. ft./lb./yr. to 0.14 cu. ft./lb./yr.
- Medium-Btu gas at around 500 Btu/cu. ft. (50% methane). High-Btu, upgraded gas at around 1,000 Btu/cu. ft.
- Revenues at $4.00/million Btu (for either medium-Btu or high-Btu applications where markets exist).
- Electrical generation revenues at about $0.06/kilowatt hour.
- Collection efficiencies at around 85% for medium-Btu gas collection systems (considering transmission losses and down-time) and 75% efficiency for high-Btu systems (again considering transmission losses and down-time).
- Electrical generating facility at 90% efficiency. This considers only transmission losses and down-time. Further reduction in efficiency should be allowed for the electrical generation/combustion process.

In determining gas recovery costs, the following equations have been presented in a leading reference on the subject.* The following equations can often be used as a first-cut determination of likely gas recovery system costs:

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(1) "Methane from Landfills: Preliminary Assessment Workbook". M. L. Wilkey, R. E. Zimmerman, and H. R. Isaacson, Argonne National Laboratory. June 1982

- Medium Btu
  \$ = 0.2 cfd + 1,200,000
  For 1 to 5 MM cfd systems

- High-Btu
  \$ = 0.7 cfd + 1,000,000
  For 2 to 10 MM cfd systems

- Electrical Generation
  \$ = 1.0 cfd + 1,000,000
  For 2 to 10 MM cfd systems

Through use of the above cited rules-of-thumb, a preliminary assessment of total system revenues, and costs can be made. By applying appropriate amortization factors, a year-by-year analysis of cash flows can be performed. The operating life of the system should be considered to be a minimum of 10 years. In most cases, pay-back of the capital costs of the system should be over that 10 year period. Actual operation of the system is likely to continue for a 10 to 20 year time span. Annual O&M costs should equal about 10% of the total capital cost.

<u>Identify Potential Markets</u>

Apart from the rules-of-thumb cited above, markets must exist for gas sale even where the minimum assessment criteria cited under Task I-1 are vastly exceeded. For high-Btu systems, contact should be made with local gas utilities. The potential for their cooperation should be ascertained. In virtually any event, a nearby natural gas pipeline must exist within 3 to 5 miles maximum of the site. If such pipelines do not exist, construction of a transmission line likely will vastly exceed any revenues which could be expected from gas sale.

In a determination of medium-Btu sale potential, identification should be performed of nearby industries who are large gas users. These industries typically need to be within three miles of the landfill site. They can be identified by spotting stacks, and other signs of high energy consumption.

In identifying potential medium-Btu users, contacts usually can be made with local utilities to determine large natural gas consumers. Considering the potential poor quality of the landfill gas, a preference should be made for those facilities with large space and water heating requirements. Facilities which consume natural gas for process uses, will likely not be able to tolerate the poor and variable quality of landfill gas.

From the two landfill gas scenarios cited above, it is obvious that medium- and high-Btu application require strategic location of the landfill near large energy consumers or gas pipelines. With the passage of PURPA and interest in electrical generation, many sites which had not hertofore been considered as gas utilization facilities now become so. Virtually any landfill is near power transmission lines of some sort. Thus, electrical generation becomes more viable in many such cases. In any event, contact should be made with the local utility to determine their avoided cost, switching requirements, potential for cooperation, and distance to transmission lines where hookups can occur.

Investigate Other Considerations

Task I-4 of the Phase I Preliminary Analysis includes addressing environmental, health, safety, socioeconomic incentives and constraints. Under environmental considerations, federal, state, and local requirements with regard to air, water, and solid waste matters should be addressed. Contacts typically include state solid waste management authorities, local health departments, and possibly the federal Environmental Protection Agency.

Other authorities who likely need to be contacted include local zoning boards, fire departments, local utilities, building commissions, etc. Ownership and financing of the system should also be addressed. Although formerly there were many federal and state tax issue incentives for development of gas utilization systems, some of these are no longer in effect.

Delineate Future Program

Upon completion of the four tasks above, a final report should be prepared, and a determination made as to whether to proceed. If the economics look favorable, a determination need not be made at this time to construct. Rather, a more detailed feasibility investigation under Phase II is appropriate to confirm the assumptions made under Phase I. After Phase II, a decision can be made as to whether to proceed with in-house development, or to select a developer. It should be pointed out that a developer can still be brought in after completion of the Phase II Detailed Feasibility Determination.

PHYSICAL AVAILABILITY OF TREE BIOMASS FOR ENERGY

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The concentration of the forestlands in the United States vary between regions and effect the economics of timber extraction and transport. Although by traditional measures industrial timber is concentrated in the West, in terms of wood for energy, the South Central and Northeast Regions are more important. About 36 billion green tons of tree biomass are contained on the Nation's 482 million acres (195 million hectares) of commercial forest land.

The most obvious source of wood for energy, manufacturing residues, is currently being fully utilized. Logging residue is not only physically available but can be recovered as a byproduct of ongoing industrial timber harvesting operations. At 1980 operating levels, when 4 quads of industrial timber products were harvested, approximately 3 quads of energy wood became available for use.

PHYSICAL AVAILABILITY OF TREE BIOMASS FOR ENERGY

Before I address the physical availability issue, I would like to tell you something about the standing forests of the United States; where they grow, who owns them, and how the tree biomass is distributed. Most of the statistics that I will be presenting are based on the U.S. Forest Service's most recent National Assessment of the Timber Situation in the United States (1), containing 1977 statistics, and a National Compilation of Tree Biomass Statistics (2) that was completed in 1981.

Total land area of the United States is 2.3 billion acres (916 million hectares), 32 percent of which is forested (Table 1). Nearly two-thirds of the forest land, 482 million acres (195 million hectares), supports trees of commercial value for industrial wood and is classed as timberland. The first slide presents these relationships for five regions of the United States. An important aspect of this comparison of all land, forest land, and timberland is that in some regions the trees are scattered over a large total land area (such as the Intermountain Region), while in others, timber covers a large portion of the land base (such as the Southeast). Although this may not effect physical availability, it certainly impacts on economic availability and the cost of tranporting wood.

TABLE 1. LAND AREA IN THE UNITED STATES BY REGION AND COVER, 1977

COVER	REGION					
	Far West	Inter-mountain	South Central	South east	North Central	North east
	(Million hectares)					
All Land	231	224	146	59	180	72
Forestland	87	56	47	37	31	41
Timberland	28	24	40	35	29	39

1 hectare = 2.47 acres

Until recently, the U.S. Forest Service inventory program focused on volume estimation: cubic feet for growing stock trees on commercial forest land and board feet for sawtimber trees. This information has been converted to cubic meters to facilitate comparisons on this slide (Table 2). Tree biomass is presented in metric tons. The relationships of volume and weight distribution by region are important when determining where tree biomass for energy might be located. Based on volume statistics, one may conclude that the Far West supports the greatest amount of potential energy wood, but based on weight, the South Central and Northeast Regions have more. This is why tree biomass statistics are required for energy wood production planning.

TABLE 2. TREE VOLUME (WEIGHT) IN THE UNITED STATES BY REGION AND STAND COMPONENT, 1977

	REGION					
Stand Component	Far West	Inter-mountain	South Central	South east	North Central	North east
	(Billion cubic meters)					
Sawtimber	2.9	0.9	0.8	0.7	0.3	0.5
All timber	7.1	3.2	3.3	2.6	1.9	3.7
	(Billion metric tons-green)					
Biomass	6.5	2.6	7.3	5.7	3.2	7.3

It is important to identify the class of timber and species, because these characteristics relate to timber use. Of the 36 billion tons of aboveground tree biomass on the commercial forest lands of the United States, nearly 27 billion tons is currently considered useable for industrial wood products (Table 3). About 17 billion tons are in softwood trees and over 5 billion tons are in small trees less than 5 inches in diameter. Most of the softwood growing stock is concentrated in the West and most of the hardwood is in the North and South. The North is mainly a hardwood region and the South is mixed.

TABLE 3. ABOVEGROUND TREE BIOMASS ON COMMERCIAL FOREST LAND IN THE UNITED STATES BY REGION, SPECIES GROUP, AND CLASS OF TIMBER

Region	CLASS OF TIMBER			ALL CLASSES
	Growing Stock	Rough and Rotten	Seedlings and Saplings	
	(Billion green tons)			
NORTH.				
Softwoods	1.7	0.3	0.4	2.4
Hardwoods	6.3	1.5	1.4	9.2
Total	8.0	1.8	1.8	11.6
SOUTH:				
Softwoods	4.6	0.1	0.9	5.6
Hardwoods	5.1	1.7	1.9	8.7
Total	9.7	1.8	2.8	14.3
WEST:				
Softwoods	8.2	0.3	0.5	9.0
Hardwoods	0.7	0.1	0.2	1.0
Total	8.9	0.4	0.7	10.0
ALL REGIONS	26.6	4.0	5.3	35.9

Tree biomass distribution by ownership statistics show that in the West most of the biomass is on public lands, while in the East, most is on private lands (Table 4). Although forest industries control only 15 percent of the biomass nationwide, over 50 percent of it is concentrated in the South.

TABLE 4. ABOVEGROUND TREE BIOMASS ON COMMERCIAL FOREST LAND IN THE UNITED STATES BY REGION AND OWNERSHIP

Region	OWNERSHIP			ALL Ownerships
	Public	Forest Industry	Other Private	
	(Billion green tons)			
North	1.9	1.4	8.3	11.6
South	1.4	2.7	10.2	14.3
West	7.4	1.2	1.4	10.0
All Regions	10.7	5.3	19.9	35.9

Land ownership effects tree biomass availability because the objectives of various owner groups differ. Multiple-use resource management is practiced on most public lands, and therefore, tree biomass production often is not maximized. Timber harvesting is not allowed on wilderness and other restricted areas. The attitudes of private landowners vary greatly over time, but free market factors tend to influence their attitude toward timber harvesting.

Forest productivity is high in the South Central and Far West Regions (Table 5). These areas can be targeted for maximum future tree biomass production.

TABLE 5. OWNERSHIP AND PRODUCTIVITY OF COMMERCIAL FOREST LAND IN THE UNITED STATES, 1977

	REGION					
	Far West	Inter-mountain	South Central	South east	North Central	North east
Ownership:			(In percent)			
public	63	75	9	10	30	10
private	37	25	91	90	10	90
Productivity:1)						
20/50 ft^3	16	53	14	17	49	29
50/85 ft^3	33	28	42	64	36	39
85+ ft^3	51	19	44	19	15	32

1) Potential annual growth in fully stocked natural stands.

Now that we have an idea of the location of tree biomass in the United States and who controls its use, the next step is to identify sources of tree biomass. Over the years, the most obvious source of biomass for energy was wood manufacturing residues. Recent regional surveys indicate that all of the economically available residue material is being used. That portion which is not converted into such traditional products as pulp chips and agricultural bedding, is being converted into energy by the forest products industry.

With the manufacturing residues fully utilized, the next most promising source of energy wood can be broadly classed as logging residues. This includes the tops and branches of harvested trees, rough and rotten trees that were passed over in the harvesting process, dead trees, and small trees that will become the next generation growing stock trees.

If all of these sources of raw material could be recovered nationwide, a two-thirds increase in total yield from the forest would result (Table 6). The gain would be greatest in the mostly hardwood northern region where a 35 percent increase could be achieved by recovering the tree tops and branches and an additional 30 percent could be realized from rough and rotten trees. The greatest gain in the South (35 percent) would come from utilizing small trees.

TABLE 6. THEORETICAL GAIN IN RECOVERY BY UTILIZING ADDITIONAL RAW MATERIAL SOURCES

SOURCE	REGIONS						ALL	
	North		South		West		REGIONS	
	Amt[1)]	Percent[2)]	Amt	Percent	Amt	Percent	Amt	Percent
Growing stk:								
Merch. bole	8.0	-	8.0	-	7.4	-	21.4	-
Tops & Brs.	2.1	+35	1.6	+20	1.5	+20	5.2	+24
Rough & Rt.	1.8	+30	1.9	+24	0.4	+ 5	4.1	+19
Small trees	1.7	+28	2.8	+35	0.7	+ 9	5.2	+24
Total	11.6	+93	14.3	+79	10.0	+34	35.9	+67

1) In billion green tons
2) Gain over merchantable bole in percent.

Currently, I believe that the most promising sources of energy wood can be a byproduct of timber products harvesting. Forest access has been gained and extraction and transportation costs can be spread over the increased raw material recovery. One tradeoff that must be dealt with during periods of increased energy wood demand and fluctuating industrial wood demand is that low levels of timber products output also mean that less energy wood would be available. But during these periods, because of decreased demand, energy from alternate sources tend to be plentiful.

To put the expected output levels in perspective, at 1980 operating levels, Saucier (3) found that an equivalent of about 4 quads was being harvested for industrial timber products. At these production levels, he estimated that 1.5 quad-equivalents in logging residue and 0.5 quad-equivalents of dead and dying trees was made available for energy wood. In addition, he estimated that 1 quad-equivalent of unmerchantable tree species and mislocated trees would become accessible. In total, 3 quad-equivalents of energy wood would be made available as a byproduct of harvesting 4 quads of industrial timber. When this is added to the 1 quad-equivalent that industry derives annually from wood manufacturing residues, this brings the total current potential to 4 quads without tapping other wood sources that are currently not physically available.

In closing, let me mention that there are other sources of wood for energy available, such as trees from urban land clearing, scrap wood from existing structures, and city tree and orchard maintenance wood, but these are not reliable sources that can be depended upon at sustainable levels year after year.

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MAXIMIZING EFFICIENCY OF WOOD FOR PRODUCT AND ENERGY

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1.0 INTRODUCTION

Consumers, merchants, manufacturers, and building contractors can increase fossil energy conservation in the United States significantly through selection of materials used in packaging and structural applications. Working together, these interest groups can accomplish more fossil energy savings by using wood in product form (e.g., paper, lumber) than by converting commercial forests into fuel farms feeding, boilers, electric utility generating stations, or alcohol synthesis plants. Consumers and merchants can accomplish these savings by preferring pulp and paper based packaging materials such as store bags, milk cartons, and meat trays, over plastic and petrochemical competitors. Building constructors can achieve fossil energy savings by using wood products in homes and light commercial structures rather than steel and aluminum substitutes.

It is of interest that wood products require less fossil energy to produce than their mineral based competitors (1). Of more interest, however, is the fact that the use of the forest to support wood products manufacture, with only low value residuals being used in energy applications, conserves more fossil energy nationally than the use of the forest exclusively as a fuel source. This is critical as forest products demand can be increased dramatically (1).

If the product route is more energetically desirable than the fuel farm route, it should be of particular interest to policy planners involved in regulations (e.g., taxes, building codes) affecting capital and resource allocation, and the encouragement of industrial growth. It should also interest those economic groups involved in product manufacture, marketing, and use. It impacts the nation's economic health. Because the determination of the best energy use of wood is most significant, it is important to demonstrate that wood grown and used for product manufacture is more energetically efficient than wood grown and used as fuel.

2.0 METHODOLOGY

In order to test the fossil energy conservation efficiency of using wood for products relative to the efficiency of silvicultural fuel farms, a baseline series of assumptions are developed:

(1) Some 400,000 acres of average (Site Class III) commercial forest land in the southeast was assumed to be available and managed for either Loblolly Pine to support products manufacture, or for American Sycamore to support energy development. This is the acreage required to meet the raw material needs of a modern forest industry complex.

(2) If Loblolly Pine were to be grown, it would be used in a state-of-the-art integrated forest products mill producing 1000 ton/day of bleached kraft paper (produced as bags), and 100 million board feet/year (bd ft/yr) of lumber (produced as 2×4 studs). Low value residuals (e.g., bark, black liquor) would be used for energy. The paper bags produced would displace polyethylene shopping store bags, and the wood studs would replace steel studs.

(3) If American Sycamore were grown, it would be used in a stand-alone power plant operated by an electric utility, displacing electricity otherwise generated at a coal-fired power plant.

These assumptions then support a basic methodology which appears as follows:

(1) For the Loblolly Pine managed stand: (a) the yields of timber for a 30-year rotation were estimated; (b) the fossil energy expenditures associated with planting and growing those trees were calculated and annualized; (c) the annual fossil energy requirements associated with harvesting those trees and transporting them to the mill were calculated; (d) the annual production of bags and studs at the mill, calculate the fossil energy saved by using those bags and studs in the market place to displace mineral based competitors, and the fossil energy required at the mill to produce those products were calculated; and (e) the fossil energy expended in the growth, harvesting,

transportation, and production of wood products were subtracted from the fossil energy saved by displacing mineral based products, to achieve annual value for net fossil energy savings associated with wood products.

(2) For the American Sycamore plantation: (a) the yields of biomass given intensive forestry and a 5-yr coppice rotation were estimated; (b) the fossil energy expenditures required to achieve those yields were calculated; (c) the fossil energy required to harvest that biomass, and transport it to the power plant was calculated; (d) the annual production of electricity (kWh) from that wood-fired power plant was calculated; and (e) the fossil energy saved by not burning coal to produce those kWh was calculated and the fossil energy costs associated with growing, harvesting, and transporting the biomass were subtracted from those fossil energy savings to estimate the net fossil energy saved per year by this strategy.

The net fossil energy savings achieved by producing products was then divided by the net fossil energy saved by generating electricity by burning wood in order to derive the energy benefit/cost (B/C) ratio associated with product plantations. Once the basic data were developed, they were subjected to sensitivity analysis. Ratios of paper to lumber were changed at the forest products mill. Energy products for the fuel farm system were also changed.

3.0 RESULTS

The results of this analysis include net annual fossil energy savings achieved by product oriented systems and biomass energy systems. Also included is a B/C comparison of the two.

3.1 Fossil Energy Savings for the Product System

In order to calculate the fossil energy savings achieved by forest products production, a specific regime was assumed. The land was planted, treated by hand application of herbicide at age 2, fertilized with 150 lb of nitrogen at age 10, thinned and fertilized again at age 20, and clearcut at age 30. Yields are estimated at 1200 ft^3 of thinnings, 3700 ft^3 of final harvest timber, and 400 ft^3 of forest residuals (2).

The mill, as configured, produces 353,000 tons of paper per year and 100 million bd ft of lumber annually. At 25,000 bags/ton of paper and 190 studs/thousand bd ft, the annual production is 8.82 billion bags and 19 million studs. Since each polyethylene bag requires 3865 Btu and each steel stud requires 50,000 Btu of fossil fuel to produce (1,2), the gross annual fossil energy savings of this system is 35 trillion Btu/yr.

The annual fossil energy required by this system includes 800 billion Btu for forestry (including herbicide and fertilizer manufacture), timber harvesting, and wood transportation to the mill. The mill consumes nearly one million lbs of steam/hr, of which 70% is supplied by burning hogged bark and spent pulping liquor, and 30% is supplied by coal. It requires 57,400 kWh/hr, of which 92% is supplied by in-plant cogeneration and 8% is supplied by purchases from a utility. It consumes 85 million Btu/hr of oil in the lime kiln. The mill, then, consumes 3.8 trillion Btu per year of fossil energy for its boilers and kilns. If the purchased electricity is generated at a coal fired power plant with a heat rate of 9,500 Btu/kWh (3), an additional 400 billion Btu of fossil energy is required annually. These energy requirements are shown in Tables 1 and 2.

The product oriented system has a gross annual fossil energy savings of 35 trillion Btu. It requires the expenditure of 5 trillion Btu/yr. The net fossil energy savings, then, are 30 trillion Btu/yr, as is shown in Table 3.

TABLE 1. Integrated Mill Energy Demands (Basis = 1 hr)

	Steam Needs	
Mill	Demand/Unit	Total Demand (lbs)
Sawmill	4,300 lb/MFB @ 50 psi[a]	51,600
Kraft mill	6,658 lb/ton @ 50 psi[b]	279,600
	13,214 lb/ton @ 150 psi[b]	555,000
Power plant		112,400
Total		998,600

	Electricity Needs	
Mill	Demand/Unit	Total Demand (kWh)
Sawmill	150 kWh/ MBF[a]	1,800
Kraft mill	1,050 kWh/ton[b]	44,100
Internal (Power, Plant, Pollution, Control, etc.)		11,500
Total		57,400

[a]Source: (2)

[b]Source: (4)

TABLE 2. Integrated Mill Energy Supplies (Basis = 1 hr)

Steam	455,200 lb from spent liquor
	225,400 lb from hog fuel
	272,000 lb from coal
	46,000 lb from desup.
	998,000 lb total
Power	52,900 kWh cogenerated
	4,500 kWh purchased
	57,400 kWh total
Other	84 Million Btu oil for lime kiln

TABLE 3. Integrated Mill Fossil Energy Savings and Costs (Basis = 1 yr)

Gross Fossil Energy Savings	
Studs: 19 Million studs @ 50,000 Btu/stud	= 0.9×10^{12} Btu
Bags: 8.82 Billion bags @ 3,865 Btu/bag	= 34.1×10^{12} Btu
Total	35×10^{12} (trillion) Btu
Fossil Energy Costs	
Forestry, harvesting, and transportation	= 0.8×10^{12} Btu
Fuel for boilers and kilns	= 3.8×10^{12} Btu
Fuel for generating purchased power @ 9,500 Btu/kWh	= 0.4×10^{12} Btu
Total	5×10^{12} (trillion) Btu
Net Fossil Energy Saved	30×10^{12} (trillion) Btu/yr

3.2 Fossil Energy Savings for the Biomass-Electricity System

The alternative to the product plantation is dedicating those 400,000 acres to the growing of American Sycamore as power plant fuel. If the regime for growing the hardwoods involves weed control, fertilization and coppice harvesting every five years, one acre of this land will produce 4.2 oven dry (OD) tons of biomass/yr (5). This equals 71.4 million Btu/acre/yr, or 28.6 trillion Btu/yr for the fuel farm.

The 28.6 trillion Btu, in a modern wood fired power plant with a heat rate of 14,100 Btu/kWh (5), can produce 2.03 billion kWh/yr. This would save 19.2 trillion Btu of coal, given a coal fired plant heat rate of 9,500 Btu/kWh. The fossil energy costs associated with growing, harvesting, and transporting the biomass to the power plant total 1.2 trillion Btu/yr (2). The net fossil energy saved by this fuel farm system is 18 trillion Btu/yr as shown in Table 4.

3.3 System Comparisons

The wood products system can save an estimated 30 trillion Btu/yr, an amount equal to 5 million barrels of oil or 1.5 million tons of coal. The wood-to-electricity system saves 18 trillion Btu/yr, an amount equal to 3 million bbl of oil or 900,000 tons of coal. The B/C ratio, then, is 1.67. Using the land to produce paper, lumber, and energy from low value residuals conserves 67% more energy than using the land only to grow fuel. Expressed another way, if this 400,000 acre tract is devoted to energy only, it could cost this country 12 trillion Btu, an amount equal to 2 million barrels of oil or 600,000 tons of coal per year.

4.0 DISCUSSION

The product plantation supporting the manufacture of bags and studs is far more energy efficient than the biomass fuel farm supporting an electricity generating station. Sensitivity analysis shows broader applicability of these numbers.

For this analysis the product distribution of lumber and paper has been changed, first eliminating lumber production and producing 1125 ton/day of paper, and then doubling lumber production while producing 890 ton/day of paper for bags. At the same time the biomass fuel is directed either to use as an industrial boiler fuel, or as a feedstock for methanol (MeOH) production. The boiler is assumed to have a thermal efficiency of 70%. The MeOH system as defined by

TABLE 4. Silvicultural Fuel Farm Fossil Energy Savings and Costs (Basis = 1 Yr)

Gross Fossil Energy Savings:

2.026 Billion kWh @ 9500 Btu/kWh[a] = 19.2 Trillion Btu

Fossil Energy Costs:

Forestry, harvesting, and transportation = 1.2 Trillion Btu

Net Fossil Energy Saved = 18 Trillion Btu/yr

[a]Assumes coal fired heat rate for fossil energy savings calculation.

Rowell and Hokanson (6), produces 98 gal of fuel (6.3 million Btu)/O.D. ton of wood. The fossil energy conservation potentials of these systems are shown as B/C ratios ranging from 1.21 to 3.47. Product systems always outperform the energy-only systems as shown in Table 5.

One can also question whether these results are more broadly applicable than the product cases of studs and bags. Bethel et al (1) demonstrated that these results are applicable to milk cartons (vs. polyethylene milk jugs), moulded pulp meat trays (vs. styrofoam meat trays), and entire construction wall systems.

It is clear, then, that wood accomplishes most in the area of fossil energy conservation if it is converted into products, with only low value residuals being used for energy. Wood accomplishes less fossil energy conservation if it is grown and converted exclusively into energy products. The reason for this phenomenon is that solar energy, captured by the tree, contributes substantially to the total energy required for the production of wood products.

5.0 IMPLICATIONS

The results indicate that substantial energy policy efforts designed to convert forests into the energy sources, apart from policies encouraging more efficient use of residuals, would be counter-productive. Such policies include taxes, codes, and the expenditure of public research funds.

These results also indicate the desirability of policies that encourage the use of wood based products as an indirect, but efficient means for employing solar energy in product manufacture. Such policy oriented actions could include broad information dissemination; changes in laws inhibiting the transportation of wood products to wider markets; changes in building codes that limit the use of wood products, and similar actions.

Given such policies, consumers can increase their contribution to fossil energy conservation by wood product selection in the grocery store, selecting milk in cartons rather than plastic bottles or eggs in pulp rather than styrofoam boxes. The department store packing dry goods in paper rather than polyethylene bags can reduce national fossil energy expenditures. The contractor, building with wood systems rather than metallic systems, can also save fossil energy for the nation. The country can accomplish more fossil energy conservation with these approaches than it can by encouraging the growing of wood as a biomass fuel.

TABLE 5. Annual Fossil Energy Savings By Alternative Scenarios[a] (Values in Trillion Btu)

Plantation and Mill Configuration	Fossil Energy Savings		
	Gross Fossil Energy Savings	Fossil Energy Costs	Net Fossil Energy Savings[b]
Product Plantations			
1125 ton/day pulp and paper mill[a]	38.2	5.2	33.0
1000 ton/day pulp and paper mill and 100×10^6 bd ft/yr lumber mill[a]	35.0	5.0	30.0
890 ton/day pulp and paper mill + 200×10^6 bd ft/yr lumber mill[a]	32.1	4.5	27.6
Fuel Farms			
Boiler Fuel	22.8	1.2	21.6
Electricity production	19.2	1.2	18.0
Methanol production	10.7	1.2	9.5

[a]Basis: 400,000 acres of southern forest, Site Class I, assumes collection of forest residuals for fuel.

These fossil energy savings accomplished by consumers using the product system are not insignificant. The National Academy of Sciences projects that, under normal conditions, paper demand in the year 2000 will be 200 million tons. Under more favorable conditions 93-190 million additional tons of paper products could be demanded, with wood products obtaining markets from mineral competitors. Lumber demand could be similarly increased (1).

On the basis of 93-190 million tons of additional paper demand, 260-540 additional integrated mill systems could be supported. Assuming a net annual fossil energy savings of 12 trillion Btu/mill system, these 260-540 mill systems could represent 3.1-6.5 quads of additional net fossil energy savings annually by the turn of the century. Those 3.1-6.5 quads represent 4 to 8% of current U.S. energy consumption.

The 3.1-6.5 quad potential is posited here not as a precise forecast. Rather it is an order of magnitude statement of possibilities that could exist. It is a demonstration that consumers in the marketplace and policy makers in government can use wood to make a significant difference in fossil energy consumption. Consumers and policy makers can use wood products as a most efficient, solar energy based, alternative to fossil energy consumption.

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"ECONOMICS & POLICY IMPLICATIONS OF INDUSTRIAL FUEL USAGE"

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ABSTRACT

Energy derived from wood currently provides about 3% of the nation's total requirements, but almost two-thirds of the wood energy is used by the forest products industry in the form of manufacturing and forest residues.

The potential exists for expanded use of these domestically available and renewable fuels, but national policies likely to affect that potential include issues associated with cogeneration of electricity, energy taxes, acid rain, federal funding of industrial R & D, and the economics of energy markets.

INTRODUCTION

As the anchorman on today's program, I perceive my role is to put the nation's use of wood as a fuel into a perspective which reflects alternative energy sources but which primarily recognizes the constraints imposed by governmental policy initiatives and actions.

HISTORICAL USE OF WOOD AS FUEL

The National Forest Products Association (NFPA) has produced a concise and informative brochure (1) which summarizes the recent historical patterns of wood fuel use in the

(1)"The Forest Products Industry - Leading the Way in Wood Energy Use", 1982; National Forest Products Association, Washington, D.C.

U.S. It reminds us that, not so very long ago, wood provided up to 90% of the nation's total energy requirements. However, today it represents perhaps only 3% of the energy Americans consume in the industrial, commercial and residential sectors of the economy. I say "perhaps" because a significant proportion of wood-based fuel is not bought and sold in conventional markets and the public statistics are therefore less than precise.

Let me illustrate: On the one hand, how many people do you know who have a chain saw and cut firewood for their home from their own or a friend's woodlands? On the other, the Forest Service recently attempted to quantify the amount of firewood consumed in the residential sector and how much householders paid for it. Of particular interest was the apparently low average price of about $65 per cord, (remembering that a dry cord of wood has the energy equivalent of about 3 barrels of oil) - but it seems that many of the people surveyed were not receiving a full cord when they took delivery, often in the back of a pick-up truck.

So much for statistics!

However, the forest products industry is unquestionably the largest current user of wood for energy, accounting for 62% of the reported total U.S. consumption in 1981. Residential use appears to have accounted for 37% of the total that year, with other industries using the remaining 1%.

I should quickly point out that the form in which wood is used for energy differs greatly between these consuming sectors. With the forest products industry, most of its wood energy is derived from residues produced in the manufacturing processes and from the forests during or following the primary harvest.

In the specific case of the pulp and paper industry, let me explain that pulp for papermaking is most commonly produced by employing chemicals to dissolve away the "glue" or lignin which binds the fibers of a tree together. After these fibers are separated, the residual lignin and chemical solution is concentrated and burned in a recovery boiler, so called because it not only provides energy from combustion of the lignin but it additionally facilitates the recovery and reuse of the original pulping chemicals. It also effectively and efficiently deals with a potential disposal problem.

In 1982, spent pulping liquors provided the pulp and paper industry with over 37% of its total energy requirements, representing the equivalent of about 122 million barrels of fuel oil. When we include the paper industry's use of bark from it's pulpwood and the hogged wood fuel derived from manufacturing and forest residues, its production processes are currently almost 52% energy self-sufficient, up from

40% a decade ago. Many individual pulp and paper plants are almost entirely energy self-sufficient.

It is a unique characteristic of the forest products industry that the tree is not only its principal raw material but also its largest source of energy. An additionally important feature of this industry is that it is the nation's leading producer of cogenerated power, - an aspect of national energy policy on which I will soon elaborate.

But before I turn to the policy issues, let me take a minute to clarify a perception of energy efficiency in the paper industry which is not always fully understood. I refer to the comparative energy balances in the use of primary and secondary fibers for paper and paperboard.

Because the production processes based on chemical pulping are so largely energy self-sufficient, it usually requires less fossil fuels and purchased energy per ton in the primary manufacture of paper or paperboard than if the same products were made from recyclable fiber in a process where virtually all of the energy must be purchased. However, when mechanical pulping processes are involved, - such as in newsprint and some groundwood papers, - there is no question that the recycled alternative requires less total as well as less fossil fuel and purchased energy per ton than in the primary process.

I draw this issue to your attention because, in 1979, a well-intentioned Congressman succeeded in having an amendment attached to a piece of legislation which virtually mandated recycling targets for the paper and paperboard industry, - along with three other energy intensive industries, - on the presumption that it would reduce the nation's consumption of oil and natural gas. Fortunately, this complex issue is now much better understood by the agency charged with implementing the legislation. Through it's trade association, the paper industry continues to endorse recycling, - primarily as an effective means of extending the nation's forest resources and of minimizing the impact of discarded paper on the nation's solid waste stream.

POLICY ISSUES AFFECTING WOOD ENERGY USE

Now let me turn to the more specific policy issues affecting wood energy use.

Those which today are of greatest concern were born almost a decade ago with the Arab Oil Embargo in 1973 and then nurtured by the 1978 Iranian Crisis. The country was rudely but convincingly confronted with its prodigious energy appetite and with its vulnerability to being cut off from its major external sources of supply.

While many of us believe that free market forces are the most efficient means of allocating scarce resources, the international and domestic petroleum markets were unequal to the magnitude of those OPEC shocks in the 1970's. Consequently, Congress undertook the unenviable task of adjusting the industrial and commercial energy market enviroments to resolve urgent and complicated problems ranging from shortages of gasoline, through threats to national defense, to the stimulation of alternative and domestically-available fuels.

In 1978, a package of energy legislation was passed by Congress, revising and establishing the basis for much of the nation's current energy policy.

Those initiatives were contained in legislation which we have since learned to identify with acronyms such as FUA (the Fuel Use Act), PURPA, (the Public Utility Regulatory Policies Act), NECPA, (The National Energy Conservation Policy Act), NGPA, (the Natural Gas Policy Act), and ETA, (the Energy Tax Act).

In the almost five years which have followed, many regulatory agencies have attempted to implement the original intent of Congress. Unhappily, a significant number of these attempts have become the subject of litigation in various levels of our court system, including the U.S. Supreme Court.

Much of the difficulty in implementing new policies stems from the laws already in place which distort individual market environments and which defy efforts to adjust the original intent of those laws to reflect unanticipated new circumstances. Regulation of the domestic natural gas market is perhaps the best example of what I mean.

Indeed, the natural gas issue provides a useful illustration of the complexity of markets which we assume to be potentially "free" but which may be structurally destined to be partially and perpetually controlled. Let me explain.

When we refer to a "free" market, we usually mean one in which each and every consumer, - whether an individual or a corporation, - is able to choose between at least two alternative suppliers. For example, if you don't care for the quality or price of gasoline at one station, you are at liberty to buy what you prefer at another.

However, if you consider the products we generally associate with utilities, - i.e., water, electricity and natural gas, - the consumer frequently has a very limiting constraint. These commodities are usually delivered to the ultimate user by a virtual imbilical cord, - the water main, the power cable or the gas line. A consumer has really no choice over who will directly supply these services to him, and it is probably this characteristic that has resulted in these services being the subject of regulated utilities. The monopolistic nature of the ultimate supply of such energy sources as electricity and natural gas is often overlooked by those who would simplify the policy aspects of energy markets and glibbly argue that all that is necessary is to deregulate them.

I would like to use the cogeneration issue to illustrate this principle, primarily because of the role the forest-based industry already plays and the potential that exists for this role to be greatly enhanced through the use of wood-based fuels.

1. Electricity and Cogeneration

At the risk of telling many of you something you already know, let me explain that cogeneration involves the sequential use of energy to produce electricity and another useful form of thermal energy from the one fuel source. To illustrate the relative efficiency of cogeneration, a typical public utility plant converts from 27% to 39% of the energy Btu input into electric power, in contrast to a typical pulp and paper mill which converts some 82% of its Btu input into both electricity and process steam.

In 1978, Congress enacted legislation in the Public Utility Regulatory Policies Act (PURPA) which was designed to encourage cogeneration by non-utilities and to provide a basis for utilities to purchase and distribute this cogenerated power to consumers at no greater cost to those consumers than if the utilities had generated the power.

As I have already mentioned, the pulp and paperboard industry is the nation's leader in cogeneration, - largely because it requires both electricity and steam in it's production processes. This dual feature is what makes cogeneration so much more efficient. The industry has recently estimated that, if the original provisions of PURPA were permanently in place, it could add 40% to it's current cogeneration capacity of about 3500 megawatts over the next five years. Much of this additional capacity would draw upon available wood residue fuels.

Regrettably, many of the industry's planned cogeneration projects have been delayed or postponed as the result of legal challenges to the regulations which were designed to implement PURPA. The litigation is now in the U.S. Supreme Court and a decision of that body is expected during the coming summer.

2. Energy Taxes

The combination of falling world oil prices and high federal deficits may provide an opportunity to impose energy taxes which either the Administration or Congress considers too good to miss.

The Administration has provided in its 1984 Budget Proposal for an excise tax on fuel oil, but to begin in October 1985 if the federal deficit exceeds 2½% of the nation's GNP.

Such a trigger appears to use an inappropriate criteria if the primary justification of a tax on oil is to prevent a reversal of the nation's effective conservation effort over the last decade. An excise tax on oil would also dampen the incentive for domestic exploration.

Alternative energy taxes, - such as a Btu tax or an oil import fee, - appear to run against the fundamental requirements of a tax, - that it be fair and equitable, and that it be easy to collect.

An oil import fee might serve to bolster domestic oil prices but would discriminate against consumers in regions of the country which are more heavily dependent on imported oil.

On the other hand, a broadly-based Btu tax would tend to place a disproportionate burden on those who, in the recent past, have converted their boilers from the more efficient fuels such as oil and gas to less efficient but domestically-available coal and wood-based fuels. While their conversions have unquestionably contributed to a reduction in the nation's dependence on imports, the result has also been an increase in their Btu consumption per unit of output.

3. Environmental Aspects of Energy Use

The issue of acid rain is already the subject of intense study and debate, and it promises to assume even greater significance as international disputes elevate the level of public concern.

Among the conventional fuels, wood and it's residues are environmentally acceptable because they have inherently low proportions of sulfur and nitrous oxides.

However, since there are increasing claims that acid rain damages forests, - (West Germany claims that 8% of its forests are either dead or dying because of acid rain), - the forest-based industry has very good reason to look at both sides of this challenging environmental issue.

4. Federal Funding of Industrial R & D

With the creation of a formal federal energy agency, Congress funded a wide range of industrial R & D projects designed to improve energy productivity in existing plants and to accelerate the development and adoption of more efficient technologies, especially in the more energy-intensive industries.

The Reagan Administration proposed virtual elimination of these programs, but Congress chose to fund them anyway.

While the forest-based industry supports the concept of reduced governmental expenditures and deficits, it sees merit in federally funded programs which address fundamental, long term and high risk energy-related R & D with broad application to a whole industry or to several industries with similar technologies. On the other hand, short term and applied industrial R & D is more appropriately the responsibility of individual corporations which will enjoy the proprietary benefits of their new discoveries.

As a specific example of the fundamental area of energy-related R & D in the forest-based industry, I would cite the poorly-understood processes of combustion of spent pulping liquors in recovery boilers which, - as I indicated earlier, - currently provide the paper industry with the energy equivalent of 122 million barrels of oil.

I would add the observation that the extent of the economically accessible fuelwood component of the nation's forest resources is far from clear and the U.S. Forest Service seems to be the logical organization to seek the answers to this important question.

5. Economics of Energy Markets

In the four preceding energy issues, - Cogeneration, Energy Taxes, Acid Rain and Industrial R & D, - I have endeavoured to identify aspects of national policies which are currently impacting the potential for expanded use of wood-based fuels.

However, with the hightened level of public interest generated over recent weeks by reports of collapsing OPEC oil prices, coupled with the President's announcement last Saturday that he will introduce legislation to deregulate natural gas by 1986, I should logically conclude by acknowledging the prospect of dramatically changing energy markets ahead.

The forest products industry has made impressive strides in substituting wood residues for petroleum fuels over the last decade and the physical potential to do more is great. However, this potential will depend largely on the comparative costs of conventional fuels such as oil and natural gas.

At a recent Conference Board meeting on Energy Policies and Strategies, an energy economist was asked what he thought of the outlook for the Synthetic Fuels Corporation. He suggested that the economic justification for many of that Corporation's long term projects would be impacted more by a $50 per barrel downward revision in the originally projected price of oil for 1990 than by any other factor. This answer, of course, zeroed in on the fact that investments in alternative energy sources depend largely on the anticipated costs of customary fuels.

If OPEC oil prices fall by as much as many analysts currently predict, - from the $34 per barrel level of last year to $27, or even $20 as a few suggest, - it will prompt the management of many industries, (including the forest products industry), as well as many householders to rethink the economic justification of plans they may have had to use more wood as a source of energy.

Let me promptly establish that, in my view, a significant drop in the world price of oil will, on balance, be beneficial to the majority of the world's population. For the U.S. in particular, the Treasury Secretary has estimated that each $3 per barrel drop in the price of oil will result in a $10 billion decline in gross domestic costs. Given the depth and duration of the recent recession, this bonus has come at a most opportune time.

As a nation, however, we should not quickly forget the serious energy lessons learned over the last decade. If indeed we have succeeded in getting OPEC out of the driving seat, we would do well to keep it that way by not relaxing our efforts to maintain and improve energy efficiency. In that context, it may well still prove the most cost-effective long-term option to invest in domestically available and renewable energy resources such as wood.

CURRENT AND FUTURE MARKETS FOR FUEL ETHANOL

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FUEL ETHANOL MARKET - 1982 UPDATE

Sales Growth

Despite a deepening recession in other areas of the economy, 1982 was the best year yet for the fuel ethanol industry. Ethanol sales, shown in Figure 1, have increased at an average rate of over 10 percent a month in 1982. Sales in September 1982 topped the 200 million gallon per month mark for the first time. The reason for this dramatic growth is evident. More fuel ethanol became available. The late 1981 completion of three large ethanol facilities, owned by Archer Daniels Midland and Pekin Energy, accounted for the early 1982 jump in ethanol sales. The recent rise in sales starting in mid-1982 was fueled by three factors: increased capacity utilization by existing producers, shifts by wet millers from corn syrup to ethanol production, and startup of three more large facilities (A.E. Staley, South Point Ethanol, and Kentucky Ag Energy).

Market Trends

The close relationship between ethanol capacity additions and sales growth implies a supply-limited market. The major reason for this supply-limited

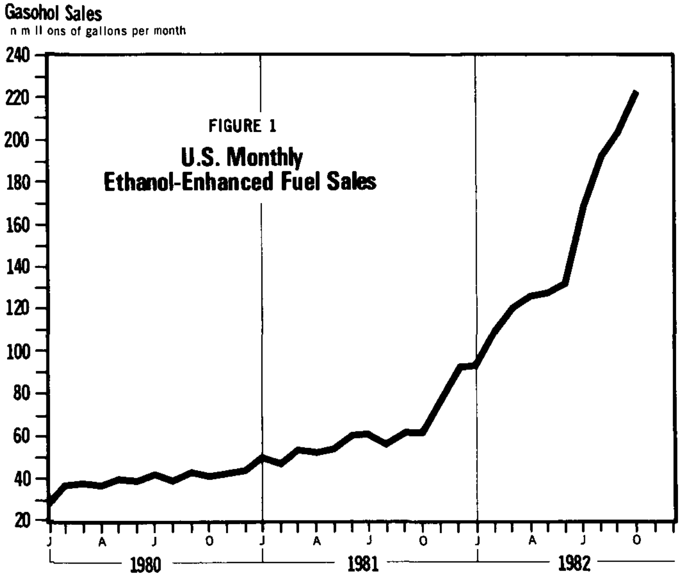
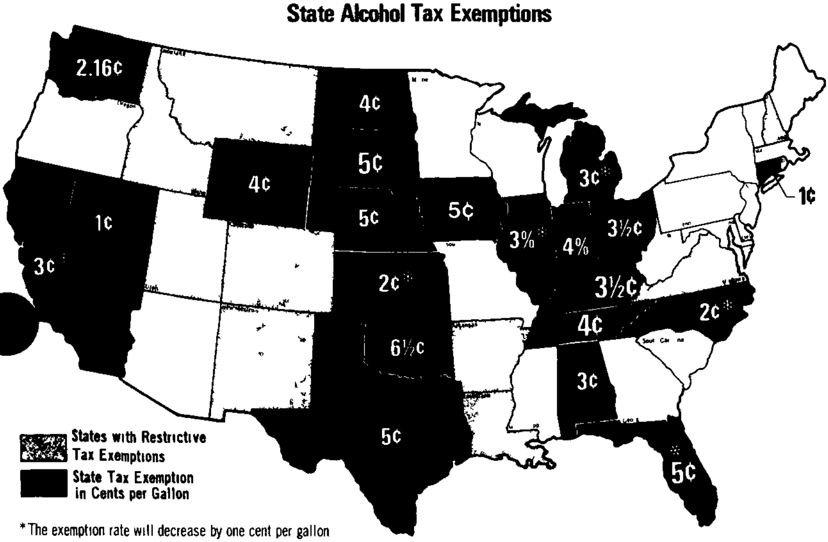


FIGURE 1
U.S. Monthly Ethanol-Enhanced Fuel Sales

FIGURE 2
State Alcohol Tax Exemptions



*The exemption rate will decrease by one cent per gallon each year Illinois rate will drop by one percentage point each year condition is the availability of state tax incentives. Figure 2 illustrates the 30 states having incentives for ethanol-gasoline blends. Although the South Carolina incentive has expired (as of January 1, 1983), both Tennessee and Kentucky have recently enacted incentives (4¢/gal. and 3.5¢/gal., respectively).

Table 1 compares the economics of a super unleaded ethanol blend with those of conventional regular unleaded and premium unleaded grades. The comparison assumes a 4¢/gal. state incentive for ethanol blends. The old Federal excise tax exemption of 4¢/gal. is also assumed, in order to reflect 1982 market conditions.

At the wholesale level, before either state or Federal taxes are imposed, 90 percent regular gasoline blended with 10 percent ethanol costs 97 cents per gallon (assuming no blending costs), significantly higher than either conventional grade. When taxes are levied and freight and dealer margin are included, the 90-octane ethanol blend costs 1 cent per gallon more than regular unleaded and 7 cents per gallon less than premium unleaded. The ethanol blend achieves 75 percent of the octane boost (i.e. 3 of 4 octane points above regular) at a fraction of the cost differential (1 versus 7 cents per gallon). While this is a significant bargain to the 7 to 13 percent of motorists purchasing high-octane unleaded grades, little incentive exists for the consumer of non-premium grades (with a 45 to 50 percent market share).

Of course, when state incentives of 5¢/gallon or greater exist, ethanol blends are often priced at or below regular unleaded grades. Here, they compete directly with the regular unleaded grades and normally attain a much larger market share. In practice, there is a fair amount of variability in the observed relationship between state incentive levels and gasoline market penetration in individual states. This variability can be attributed to high transportation costs, eligibility restrictions on the ethanol incentive (some forms of these have questionable constitutionality, see Archer Daniels Midland Company vs. the State of Minnesota), alcohol unavailability, poor market potential, and/or market inertia.

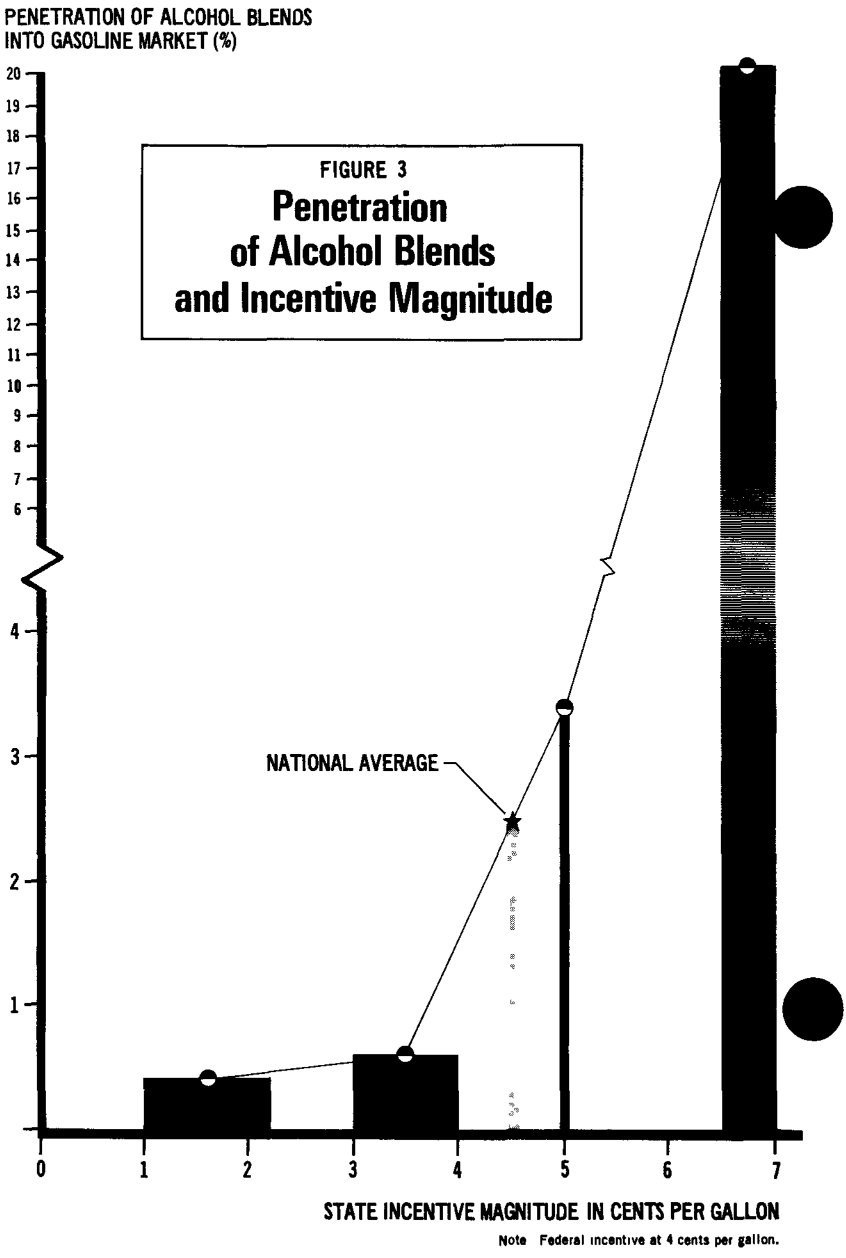
Despite these variables, there is a good relationship between incentive levels and penetration rates when viewed on an aggregate level. Figure 3 shows such a relationship for 20 states offering incentives. States which were not considered generally had restrictive incentives or had only recently enacted incentive legislation. The states penetration data for the first 6

TABLE 1

COMPARATIVE ECONOMICS OF "SUPER UNLEADED WITH ETHANOL"
VERSUS CONVENTIONAL GASOLINE GRADES
(in cents per gallon)

	87-Octane Regular	90-Octane Super With Ethanol	91-Octane Premium
Unleaded Gasoline			
Regular @ 90¢/gal.	90	81	--
Premium @ 94¢/gal.	--	--	94
Ethanol @ 160¢/gal.	--	16	--
Terminal Price	90	97	94
Federal Excise Tax	4	0	4
State Tax*	10	6	10
Freight	1	1	1
Dealer Margin	6	8	10
Retail Price	111¢/gal.	112¢/gal.	119¢/gal.

* Illustrative state tax of 10¢/gal. for gasoline and a 4¢/gal. incentive for alcohol fuels. Old Federal excise tax exemption assumed.


PENETRATION OF ALCOHOL BLENDS
INTO GASOLINE MARKET (%)
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
4
3
2
1
FIGURE 3
Penetration
of Alcohol Blends
and Incentive Magnitude
NATIONAL AVERAGE
0
1
2
3
4
5
6
7
STATE INCENTIVE MAGNITUDE IN CENTS PER GALLON
Note Federal incentive at 4 cents per gallon.

months of 1982 were grouped by incentive level (in cents per gallon) as follows: 6.5 to 7, 5, 3 to 4, and 1 to 2.

As shown in Figure 3, penetration rates in states having incentives 5¢/gallon or greater are significantly higher than those in lower levels of incentives. Again, this suggests that states with high incentives allow ethanol blends to compete with regular unleaded prices and achieve high penetration.

Supply Diversification

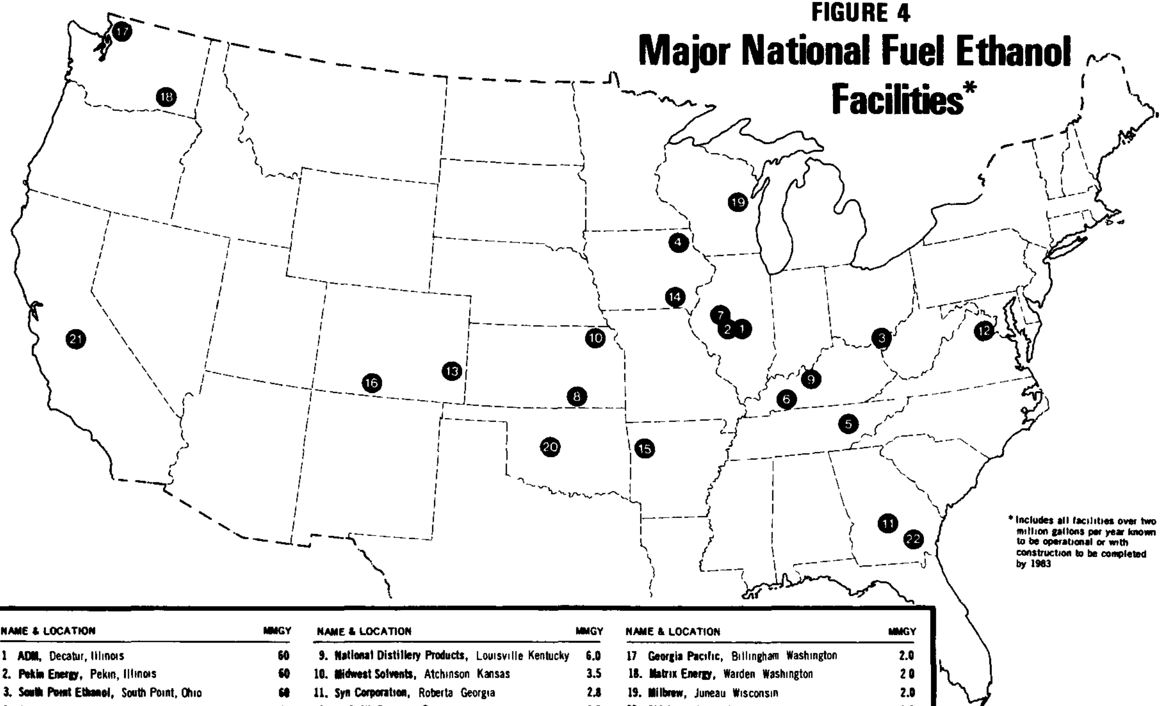
Currently, there are 22 fuel ethanol production facilities in the United States. These are shown in Figure 4. Capacities noted on Figure 4 exclude industrial or beverage alcohol capacity. Total United States fuel ethanol capacity is estimated to be 347.4 MMGY (million gallons per year). Approximately 121 MMGY of capacity has only recently come on-line and is not expected to reach full capacity until mid-1982.

The large number of ethanol suppliers has increased competition dramatically in most areas of the country. Two years ago, one large ethanol facility controlled the market. Currently, there are five ethanol producers each supplying over 20 MMGY. Smaller facilities, mostly scattered outside the Iowa-Ohio-Tennessee triangle, compete with larger facilities for local markets. Although smaller facilities have higher production costs, their lower transportation costs let them compete with larger facilities. This increase in market competition coupled with low corn prices, has been the major factor in ethanol's 20 cents per gallon price decline over the last two years. Although it has been speculated that falling gasoline prices will end ethanol's competitiveness, ethanol price declines have equalled those of gasoline.

Future Trends

Over the next year, the April 1983 1¢/gal. increase in the Federal excise tax exemption for ethanol blends will accelerate growth in ethanol sales. Sales of ethanol blends should reach 330 to 350 million gallons per month by mid-1983. Prices will remain at current levels (145-155 cents per gallon) until mid-year, as new producers fight for market share. Having recently enacted incentive legislations, Kentucky and Tennessee, will be key states for new sales growth. Due to their substantial incentives and large gasoline markets, Texas and Florida markets have the largest growth potential for 1983.

FIGURE 4
Major National Fuel Ethanol Facilities*



* Includes all facilities over two million gallons per year known to be operational or with construction to be completed by 1983

NAME & LOCATION	MMGY	NAME & LOCATION	MMGY	NAME & LOCATION	MMGY
1 **ADM**, Decatur, Illinois	60	9. **National Distillery Products**, Louisville Kentucky	6.0	17 **Georgia Pacific**, Billingham Washington	2.0
2. **Pekin Energy**, Pekin, Illinois	60	10. **Midwest Solvents**, Atchinson Kansas	3.5	18. **Matrix Energy**, Warden Washington	2.0
3. **South Point Ethanol**, South Point, Ohio	60	11. **Syn Corporation**, Roberta Georgia	2.8	19. **Milbrew**, Juneau Wisconsin	2.0
4. **ADM**, Cedar Rapids, Iowa	45	12. **A. Smith Bowman**, Reston, Virginia	2.5	20 **Oklahoma Gasohol Inc**, Hydro, Oklahoma	2.0
5. **A.E. Staley**, Loudon, Tennessee	40	13. **Colorado Gasohol, Inc.**, Washington Colorado	2.5	21. **Raven Alcohol Distillery**, Selma, California	2.0
6. **Kentucky Agricultural Energy**, Franklin, Kentucky	21	14. **Van Buren County Alcohol**, Bonaparte Iowa	2.5	22. **Southeast Georgia Agricultural**, Douglas Georgia	2.0
7. **ADM**, Peoria, Illinois	15	15. **White Flame Fuels**, Van Buren Arkansas	2.5	TOTAL	347.4
8. **American Gasohol Refiners**, Wichita Kansas	10	16. **Colorado Agricultural Energy**, Monte Vista Colorado	2.2		

ETHANOL BLENDING AT THE REFINERY

Today, ethanol is blended at gasoline terminals to produce a premium octane fuel from regular octane grades. This is not octane enhancement in the traditional sense, since no modification is made at the refinery level. Refinery blending of ethanol is preferable to terminal blending since it optimizes octane benefits, allows for improved quality control, and need not affect product mix.

Lead Phasedown

Since lead is one of the cheapest octane enhancers, the Environmental Protection Agency's (EPA) recent overhaul of the lead phasedown regulations improve current and future economics of octane enhancers. Despite initial attempts to relax the lead phasedown schedule, EPA's final regulation significantly tightened restrictions on lead usage in gasoline. Prior regulations limited lead usage by large refiners to 0.5 grams lead per gallon gasoline. Small refiners (crude capacity less than 50,000 barrels per day and not owned by a large refiner) were scheduled to achieve the 0.5 gram per gallon standard by October 1982 and meet an interim "sliding scale" standard of 2.5 to 0.8 grams per gallon, depending on gasoline volume. These limits were averaged over the refiners total gasoline production. As the leaded fraction of a refiner's gasoline decreased due to attrition of older cars (post-1974 cars equipped with pollution control catalysts must use unleaded gasoline), the lead content of leaded gasoline could increase.

The new regulations require all refiners to meet a 1.1 gram per gallon standard for leaded gasoline only. Large refiners must comply by November 1, 1982. Small refiners must comply by July 1, 1983 and must comply with a 1.9 gram per gallon standard (for leaded gasoline) in the interim. The definition of small refiners is narrowed to include only refiners in existence prior to October 1, 1976 and producing less than 10,000 barrels of gasoline per day. The regulation also applies to imported gasoline (previously unregulated) and allows inter-refinery lead averaging.

The effect of the new regulations is to significantly reduce future lead use. Because the market share of leaded gasoline is expected to decline significantly in the future, the new standard prevents the potential increase in lead content of leaded gasoline allowed under the old "pool-averaged" standard. EPA estimated the new regulations will decrease lead emissions from gasoline use 27 percent by 1985 and 58 percent by 1990. Total reduction in lead emissions through 1990 is estimated at 115.7 billion grams. This is equivalent to about 2 years of lead consumption (at the current lead usage rate) or about 3.7 billion gallons of ethanol.

Small refiners and the so-called "lead blenders" will be affected significantly by the new regulations. For these refiners, lead usage must be reduced by about 50 percent from levels allowed under the earlier, more lenient regulations. Many lead blenders and some small refiners are expected to close due to the new requirements. Remaining small refiners have a number of options to supplement octane supply: upgrade or add octane processes at the refinery, reduce production of high-octane unleaded gasoline grades, or purchase octane enhancers such as ethanol, toluene, methanol/TBA (tert butyl alcohol) blends, or MTBE (methyl tert butyl ether).

Generally, large refiners will be unaffected by the new regulations until the latter part of the decade, when unleaded gasoline will dominate the gasoline market. At this time, processing modifications should allow most large refiners to meet this octane deficit at minor incremental cost.

Octane Needs - Current and Future

Compared to the octane deficits resulting from the revised lead phasedown regulations, the continuing shift to unleaded gasoline will significantly increase future octane demand. The growing demand for unleaded gasoline, especially high-octane grades, displaces demand for lower octane leaded gasoline, as pre-1974 cars are replaced. Leaded gasoline's clear pool (i.e. without lead) octane rating of 83 to 84 R+M/2 is much lower than those of unleaded gasolines (87 to 88 R+M/2 for regular and 90 to 93 R+M/2 for premium). Projected market shares among gasoline grades affects refinery octane requirements, as shown:

Grade	Octane Rating R+M/2	Market Share %(1)(2) Current	1985	1990
leaded regular*	88.9	47.8%	28.6%	12.2%
unleaded regular	87.4	40.6	50.4	58.8
unleaded premium	91.7	11.6	21.0	31.0
Clear Pool Average (R+M/2)		86.9	87.7	88.5

* Includes leaded premium

(1) Energy and Environmental Analysis, Inc. Highway Fuel Consumption Model, prepared for U.S. Department of Energy, July 1982.

(2) Feldman, M.B. and D.G. Rangow, Modern Gasoline Economics, Hydrocarbon Processing, December 1982.

These projections of gasoline market share suggest that United States clear pool octane ratings will increase from the current level of 86.9 to 87.7 by 1985 and 88.5 by 1990. These estimates of octane demand can be compared with estimates of octane supply to assess the degree of octane deficit, if any.

	In Clear Pool Octane		
	Current	1985	1990
Octane demand	86.9	87.7	88.5
Octane supply (3)	87.0	87.7	88.3
Octane Deficit	-0.1	0.0	0.2

The comparison suggests there is currently an excess of octane, i.e. octane supply exceeds demand. This conclusion is supported by the current low market prices of octane enhancers and the curtailment of plans to build several MTBE facilities. However, this surplus is expected to disappear by 1985 and octane shortages are projected through 1995.

Octane Economics - Processing Versus Additives

Despite the likelihood of a current octane glut, there will always be some refineries in need of octane - either on a spot or constant basis. The costs of octane improvement vary from refinery to refinery and according to market conditions. Since the use of lead is restricted, refiners typically increase processing severity or purchase octane enhancers to meet octane needs. At today's depressed prices, some octane enhancers offer an economical alternative to processing.

Table 2 compares the cost-effectiveness of incremental refinery octane costs (via reforming) to lead, ethanol, methanol/TBA, and toluene. Lead addition, though restricted, represents the cheapest octane source at 7.2 cents per octane-barrel (¢/ONB) (i.e. the cost to raise one barrel of gasoline by one octane point). Ethanol and methanol/TBA blends were slightly less expensive than incremental reforming at 18.8 and 21.8¢/ONB compared to 28.0¢/ONB for reforming. Since toluene is derived from reforming, it is not surprising that the toluene's octane cost is more expensive than typical reforming costs.

Although the economics of ethanol and methanol blends appear more favorable than refinery processing,

(3) W.D. Route, et al. GM Sees Octane Surplus; Wants Improved Diesel Fuel in Future, Oil and Gas Journal, January 25, 1982.

TABLE 2

OCTANE IMPROVEMENT ECONOMICS

Source	Octane Cost Cost per Octane Barrel (R+M/2)
Incremental reforming	28.0¢
Lead	7.2¢
Ethanol	18.8¢
Methanol/TBA	21.8¢
Toluene	58.6¢

ASSUMPTIONS

Other Source	Cost $/gal.	Research Octane Blend Value	Motor Octane Blend Value	RVP
Ethanol	1.00	132	103	19
Methanol/TBA	0.85	118	93	42
Toluene	1.10	113	94	2
Gasoline	0.90	91	83	10
Butane	0.70	94	89	59

NOTE: Ethanol cost of 1.50$/gal. FOB plant minus 0.50 $/gal. Federal exemption credit

SOURCES: Octane costs for reforming and lead: Feldman, M.B. and D.G. Rangnow, ibid.
Enhancer assumptions: Greer, D.C. and W.J. Kulakowski, Use of Ethyl Alcohol as an Octane Booster, 1982, NPRA Annual Meeting, Ma[illegible] 21-23, 1[illegible]

there are two caveats. First, the octane enhancer economics do not include transportation costs, refinery storage costs, and costs to prepare the distribution system for alcohol. These costs are highly refinery-specific and could range from 5 to 20 cents per gallon alcohol. Second, because gasoline demand is slowly decreasing, the volume from octane enhancer addition must be offset by decreased crude throughput at the refinery. If a refinery profit margin of $1.00 to $2.00 per barrel of crude processed is assumed, ethanol or methanol addition will entail an economic penalty on the order of 5 to 10 cents per gallon alcohol.

Despite these caveats, it is apparent that current prices of ethanol and methanol/TBA are very low relative to toluene and refinery processing. For ethanol, the Federal excise tax exemption of 5 cents per gallon allows very inexpensive octane enhancement. When state incentives for ethanol use are considered, the cost-effectiveness of ethanol as an octane enhancer is even greater. If the octane glut disappears, as expected, the value of these enhancers should improve significantly.

COMMERCIAL ETHANOL PRODUCTION & MARKETING ON A LARGE SCALE

Arthur E. Stuenkel
President

PEKIN ENERGY COMPANY

In the past year, the ethanol industry has gone from surplus to shortage, back to abundant supplies. Our markets have expanded, usage has expanded, and new plants have come "on stream". Ethanol distribution has matured to allow easy access to the product in viable marketing areas. However - today, with the current oil glut situation, declining worldwide crude oil prices, and declining gasoline prices at the pump, we are faced with greater challenges than ever before. Whether or not we are successful in meeting these challenges, and adapting our business accordingly, could mean continued success or dramatic failure. In order to explain that statement, let me first give a capsulized view of the recent history of ethanol-blending into gasoline.

Originally, of course, there was gasohol. In 1979, the product's greatest need was as a fuel extender. In many cases, because of the disparity between ethyl alcohol and gasoline, gasohol was priced for substantially more at the pump. The federal 4 cent-a-gallon incentive was in place, but only 12 states had additional incentives in place and, of these, only 8 allowed an incentive on an unrestricted basis. However, lines were long and gasoline was short. Ethanol was able to command a higher value, even with the limited incentives. At this time, use of ethanol was limited to one product. There was one major manufacturing plant in the United States with limited distribution.

In 1981, after the shortage, came super-unleaded with ethanol. The ethanol-blending industry grew up from the original generic term to a product emphasizing ethanol's major benefit: its ability to increase gasoline octane ratings. As gasoline prices during this period stabilized, more dependence on tax incentives took place. By this time, some 34 states either had passed, or were in the process of passing, ethanol-blended fuels incentives to encourage market development, with the ultimate goal of providing jobs, creating industry, using domestic raw materials, and reducing dependence on foreign oil. During this period of time, product was primarily used in one grade, with the ethanol being positioned so as to "give away" its octane value as an incentive to induce the marketer to try it. More plants, including Pekin Energy, came "on stream". The industry opened up terminal locations near gasoline sources to reduce the expense of blending the two components together. Ethanol, through the additional tax incentives, was able to achieve greater market penetration across the United States.

Now, we have the current era of ethanol-enhanced motor fuels. In the last year, we find, by improving efficiencies of use, the product can be used as a profit-extender. Multi-grade blending has improved octanes in both leaded and unleaded gasolines. Distribution has continued to develop to make ethanol more accessible, even though the majority of blending is still done at the truck rack. New plant openings in 1982 have helped to overcome the critical mass needed to make this industry viable; although, at times, demand has exceeded supply. However, as the current worldwide oil glut grows, the dependence on tax incentives still exists.

Gasoline prices, instead of increasing as had been forecast just a few years ago, have continued to decline as a result of the glut situation. The disparity between ethanol and gasoline still exists and, at the present time, the only way to close this gap is through the use of both federal and state incentives. I think you have all seen the will of the Congress by their overwhelming support for the continuation of the ethanol program, as evidenced by the 1 cent-per-gallon exemption increase on ethanol-enhanced fuels passed late last year. They see the need for a viable ethanol industry for the many reasons of: balance of payments, continued dependence on foreign oil, pressure from farm groups, and the environmental benefits of the product. The country needs the ethanol industry to help complement the current federal programs to eliminate present and projected grain surpluses. Pekin Energy

Company, alone, with its requirement of 24 million bushels of corn to make 60 million gallons of ethanol annually, would support 2,000 average-size farms.

State incentives are another matter entirely. Different states have different incentives. We have found that these differences create unusual distribution patterns. At the present time, we are finding ethanol being shipped long distances, in order to be used to maximum benefit, while other ethanol shipments are made in the opposite direction. We have also seen significant market shifts when tax laws are changed.

In order to eliminate the many differences that we see in state incentives, and to provide some consistency for the marketing of ethanol-enhanced motor fuels, Pekin Energy Company suggests that each state look to a 3 to 4 cent-a-gallon incentive on an unrestricted basis. An incentive of this magnitude, when coupled with the current federal incentive of 5 cents per gallon, would allow ethanol to be competitive with gasoline. If all states were to adopt such a posture, markets would become more spread out, and more consumers would be able to take advantage of the higher octane, cleaner burning fuel that ethanol enhancement offers.

These incentives are needed to maintain the ethanol industry in the short term, until 1992. However, all of these incentives, including the federal excise tax exemption, are meant to be nothing more than bridges to help the ethanol industry become established to the point where it can stand on its own. We, in the industry, must look to the day when we will have to stand on our own and compete in the marketplace without these incentives. Our long-term planning must revolve around this fact of life.

Pekin Energy Company, since its inception in 1981, has tried to be the lowest cost manufacturer and distributor of ethanol in the marketplace. As others have done, we attempted to establish ethanol distribution points in the closest possible proximity to available gasoline supplies. This meant placing ethanol in those markets where sufficient incentives existed to allow us to market competitively with gasoline. We have continued to strive to provide the lowest cost transportation, to look at alternative means of product movement and, in general, to realize the economies of scale. We now see, in the industry, more efficient truck and rail movement than ever before. We see that barge movement is on the increase, and product exchanges have begun to take place.

However, even with all the efficiencies I have just described, we find, at the present time, both the producers and the marketers are giving away octane values. Because of declining prices and the declining gasoline market, marketers see ethanol as being viable, if they can stretch an already very slim margin. In some cases, we have found the consumer actually receiving 90 octane unleaded with ethanol at a cheaper price than 87 octane unleaded gasoline. Ethanol is the only octane improver on the market today that is not commanding its true value.

The trend for declining gasoline markets should continue over the next 5 years. It is anticipated that total S. demand for motor fuel will drop approximately 11 lion gallons between 1983 and 1988. Unleaded gasoline ket share currently comprises about 58% of total sales and will increase steadily over the next 5 years to approximately 75%. Gasoline retail pump prices, while continuing their current decline in response to the oil glut situation, should bottom out and are expected to increase during this period.

All of these factors point to the need for our industry to begin work with the petroleum refiners to provide non-leaded octane enhancement at competitive prices. Ethanol must begin to take its place along with the other octane enhancers, including MTBE, Toluene, TBA, or whatever. At the refinery level, we can achieve the efficiencies of scale needed to reduce the cost of product distribution and, also, we can begin to take advantage, for the first time, of available product mixes, in order to place ethanol at a level where it will produce the maximum return for both the refiner and the ethanol producer.

At the present time, a petroleum refiner has two distinct methods of improving octane ratings. These are the addition of blending agents or additional reforming. Both methods are flexible, and both are under his operational control. To minimize his expense in producing high-octane gasoline, the refiner must compare the cost of blending agents versus the cost of additional processing and lower gasoline yields.

Adding 10% ethanol to an 84 octane (R+M)/2 base fuel, we obtain a greater than 4 octane number increase. When comparing this to the other octane enhancers, we find that this is 1 number better than MTBE and greater than 2 mbers better than Toluene and TBA. Therefore, on a lon-to-gallon basis, ethanol provides a greater octane ting boost than do the other available octane enhancers.

Current list prices for Toluene and MTBE are approximately 50 cents per gallon below current list for ethanol. However, by using the federal blender's tax credit of 50 cents per gallon, which is in effect until 1992, a refiner can use ethanol to achieve a greater octane value increase at essentially the same cost as other octane improvers. The use of this tax credit should help lessen the dependence on the various state tax incentives and will mean the first step toward ethanol standing on its own.

Another distinct advantage of using ethanol at the refinery is the efficiency of refinery distribution. We, in the industry, must work with refiners and transportation carriers to overcome some of the technical problems that now exist in the manufacturing and distribution of ethanol-enhanced motor fuels. I firmly believe that these problems can be overcome, if the industry can meet this challenge.

Will our industry meet this challenge? Let me give you an example of how our industry has met challenges in the past.

Last May, in Chicago, at the Alcohol Week Conference, Pekin Energy Company made a presentation at a time when ethanol supplies were abundant; supply was outstripping demand at an alarming rate; new plants were coming "on stream" momentarily. People at the conference were more worried about the ethanol glut than the oil glut. I made a simple comment, at that time, to the effect that if ethanol-blended fuels just had 1% share of market in those states with an incentive of 3 cents or more on an unrestricted basis, this would amount to 5.3 billion gallons of blended fuel, or 530 million gallons of alcohol, which was double the end-of-the-year industry capacity. What happened?

Anyone using ethanol knows that during the period of late September thru mid-December, the industry was on a virtual allocation basis. Through aggressive marketing, we expanded the market much faster than anyone expected.

Today, thanks to new plants coming "on stream", we are in a more stable product supply environment. The industry has proven that it can make the changes, where needed. I am confident that it will continue to do so, because it <u>must</u> do so.

Yes, today's marketing of ethanol-enhanced motor fuels is demanding. Gasoline is plentiful. Refineries are not even running at capacity, and many have closed.

However, let's not forget the 1973 Arab oil embargo and the 1979 Iranian crisis, which both, overnight, transformed this country from a gasoline surplus situation into a gasoline shortage situation. How quickly we forget the effects of this country's balance of payments, the effects on inflation rates, the effects on industry and individual. At best, the current supply and demand situation has given the country some breathing space -- some time to put our future energy plans in order. Ethanol-enhanced fuels should be part of these future energy plans.

CURRENT MARKET TRENDS IN ACTIVE SOLAR ENERGY

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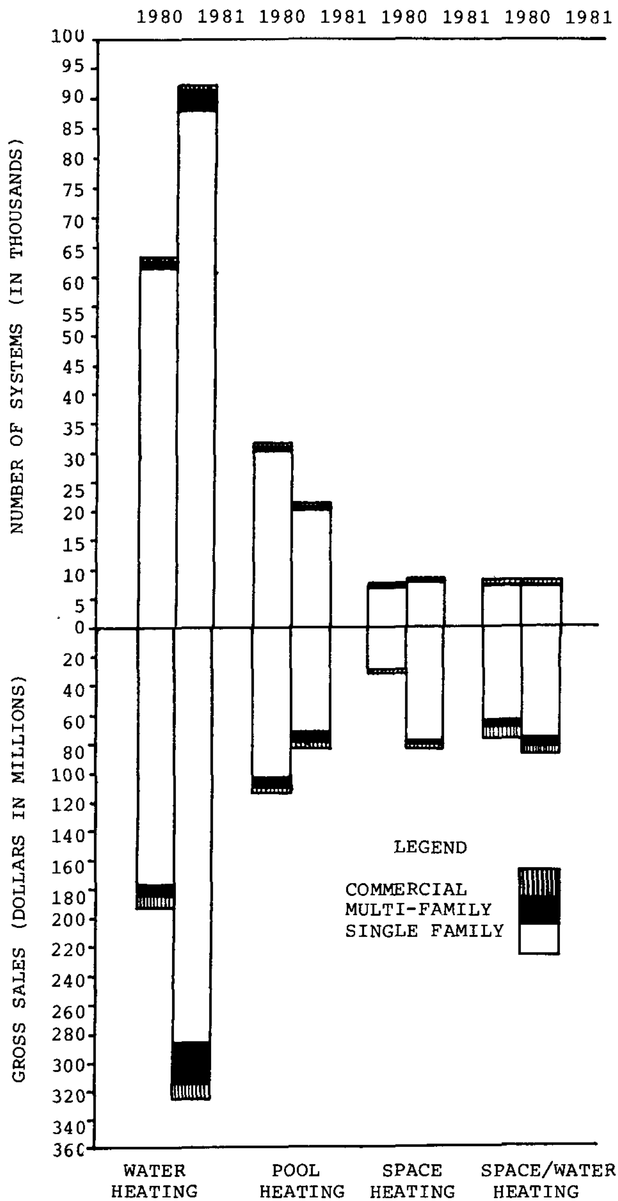
To close the information gap concerning market trends in active solar energy systems, the Energy Information Administration of the U.S. Department of Energy contracted with Applied Management Sciences, Inc. to conduct national surveys of solar installation activity for the years 1980 and 1981. Close to 6,000 companies were surveyed in 1980, yielding almost 3,500 responses. The following year over 6,700 firms were surveyed, with total responses numbering over 3,500. By carefully projecting from these responses, Applied Management Sciences estimated industry totals. The references and conclusions presented here cover only active and thermosiphon systems. More detailed and complete data presentations can be found in two reports available from the Energy Information Administration: 1980 Active Solar Installation Survey and 1981 Active Solar Installation Survey.

THE NATIONAL PICTURE

The national installation trends presented in Chart A reveal that the number of solar energy systems installed in the United States expanded dramatically from 1980 to 1981. To be more precise, the total number increased from an estimated 113,598 in 1980 to 132,867 in 1981--an increase of 17 percent. The dollar value of these new

CHART A
ACTIVE SOLAR MARKET TRENDS
1980-1981



installations rose 37 percent--from approximately $437 million in 1980 to $598 million in 1981. Important shifts within the industry were evident, however.

For the industry as a whole, domestic water heating is the dominant application, and has increased its share of the market from 56 percent of all installations in 1980 to 70 percent of all installations in 1981. The total number of DHW systems installed in the United States in 1981 increased to an estimated 92,666, with the vast majority--88,300--being installed in single-family homes.

Offsetting the significant increase in water heating installations is the drop in pool heating activity. Pool heating installations in all sectors fell from 31,696 systems (28 percent of all installations) in 1980 to 21,763 systems (16 percent of all installations) in 1981. There was a corresponding drop in the value of gross sales, from over $113 million in 1980 to about $82 million in 1981. Space heating and combined systems showed smaller shifts.

As illustrated in the chart, the level of gross sales for water heating and pool applications moved in proportion to the number of systems installed. The dollar value of space heating sales, however, showed a relatively large increase in proportion to the number of new systems installed. This was probably due to increased penetration in colder states, where more costly systems are required. Also, high-cost multifamily and commercial installations, though relatively few in number, account for a significant share of total gross sales, particularly in water heating and space heating applications.

The single-family sector continues to dominate the market for active solar systems, accounting for 95 percent of the installations and 87 percent of the gross sales in 1981. The year-to-year comparision shows that the multifamily sector has gained in market share, largely because of increased water heating applications, while the commercial sector posted a slight decline in market share. Though there are no data available yet for 1982, the installation of residential systems continues to dominate the market, and the shift from pool heating to water heating appears to be ongoing as well. Overall, however, 1982 may prove to be a flat year for the industry.

From an applications perspective, water heating systems predominate in every sector. Water heating installations have received a boost from rising electricity and natural gas prices, and from state and federal tax credits that appear to be taking hold and having a pronounced effect on the market. The sale of pool heating systems, on the other hand, appears to be suffering from an increasingly saturated market and less favorable treatment or ineligibility under most tax incentive legislation. Space heating has shown substantial growth in absolute terms, though this growth is thus far concentrated in certain states where substantial incentives exist.

Table 1 presents data on the average cost and size of the systems that were installed. Multifamily and commercial systems are very site-specific, and it is extremely difficult to generalize about their size or cost. Single-family systems tend to be more uniform though significant variations can occur across different regions of the country.

Table 1: The Average Cost and Size of Systems*

Application	Year		Single-Family	Multi-Family	Commercial
Domestic Water Heating	1980	Cost	2,892	5,713	11,974
		Size	59	143	388
	1981	Cost	3,235	8,171	13,218
		Size	61	280	517
Pool Heating	1980	Cost	3,379	6,803	13,377
		Size	367	888	1,208
	1981	Cost	3,455	7,522	15,019
		Size	376	820	1,212
Space Heating	1980	Cost	3,591	2,785	10,932
		Size	146	167	702
	1981	Cost	9,389	6,537	11,224
		Size	287	312	340
Combined Space and Water Heating	1980	Cost	8,080	11,097	47,91[illegible]
		Size	358	360	1,18[illegible]
	1981	Cost	9,663	14,294	34,452
		Size	224	390	1,154

*System costs (in dollars) and size (in square feet of collector) are based on a national weighted average.

Supporting the dominant position of single-family water heating systems, both average size and cost appear to be stabilizing. This relative price stability is expected to continue throughout 1982, in part because most systems are pre-engineered, packaged retrofit systems (86 percent of the single-family water heating installations made in 1981 were retrofits). It is noteworthy that in both the single-family and multifamily sectors, every type of solar application has shown an increase in its average installed cost. For most water heating and pool heating applications, these increases in cost were more or less in step with the general rate of inflation, but for space heating and combined space/water heating systems, the increases in average cost were generally steeper than the inflation rate.

Thus, even though installations are running at approximately 20 million square feet a year, no evidence of cost reductions due to economies of scale appears to exist when viewed in terms of the total installed cost that consumers are paying. Manufacturers, however, are striving for and achieving some reductions in costs. Therefore, it would appear that increases in the cost of transportation and installation are offsetting any cost savings being realized in manufacturing.

INDUSTRY TRENDS

In 1980, 3,437 firms or individuals in the United States responded to the survey of active solar energy businesses. In 1981, this total grew slightly, to 3,563 firms or individuals. Table 2 indicates how their activity was distributed.

Table 2: Distribution of Industry Activity

Distribution	Percentage of Total 1980	1981
Number of Installations		
0	50.1	40.8
1 - 25	36.3	41.6
26 - 50	4.8	5.9
51 - 75	2.4	2.9
76 - 100	1.3	1.5
101 - 499	4.2	5.8
500 - 999	0.5	1.0
1,000 or more	0.4	0.5
Total	100.0	100.0

Table 2: Distribution of Industry Activity (con't.)

Distribution	Percentage of Total 1980	1981
Percentage of Total Business Sales from Active Solar Systems		
0	37.2	43.1
1 - 24.9	33.4	31.3
25 - 49.9	4.3	5.0
50 - 74.9	4.1	4.6
75 - 100	21.0	16.0
Total	100.0	100.0

Note: Some firms or individuals may have installed "free" systems for their own use, or may have sold systems to other entities who actually installed them.

The overwhelming majority of the firms surveyed reported that they install 25 or fewer systems a year. On the other end of the spectrum, only approximately one half percent of the firms in 1980 and 1981 reported 1,000 or more installations.

A large majority of firms also indicated that solar activities accounted for less than 25 percent of their total business sales in both years, though the next largest grouping consists of "specialist" firms where solar activities accounted for 75 to 100 percent of sales.

Two additional trends underlie these distributions. First, approximately 35 percent of the firms surveyed do fewer than five installations per year and these account for only about two percent of the industry's total square footage installed. On the other hand, approximately 7 percent of the solar installation companies in the United States are installing 100 or more systems per year, accounting for about 75 percent of the total installed square footage.

Second, firms that have been in business for five years or longer (about a third of the companies surveyed) are responsible for some 60 percent of the square footage installed and claim over half of the industry's gross sales. This trend appears to be continuing, with the more mature firms tending to capture a larger share of the market. Also, from year to year, more firms are reaching this maturity level and entering that small group at the top--now numbering about 250 companies--that do more than 100 installations a year. In absolute terms, however, the largest increase in companies doing active solar installations still occurred at the bottom end of the scale (25 or fewer installations per year), where new solar firms or subsidiaries tend to be categorized.

Traditionally, most firms working with active solar energy systems maintain other business interests, such as plumbing or HVAC contracting. This is still the case today. In fact, the data show that the number of firms "specializing" in solar installations decreased somewhat from 1980 to 1981, suggesting that the trend toward diversification in products and services may be spreading. Some firms are expanding into passive solar energy systems, wind, PV's, and conservation products and services, while others add more conventional products, such as insulation and wood stoves. Only about one company in every five that was surveyed in 1981 earned the majority of its income solely from the installation of active solar energy systems.

To what extent these trends are continuing in 1982 is difficult to ascertain. Certainly the industry will continue to be heavily populated with small firms that install only a dozen or two systems a year. But there is also evidence that the recession, in addition to flattening sales all across the board, has taken a particularly heavy toll in bankruptcies among the smaller firms, which are usually not as well capitalized and have less access to credit than larger companies. Moreover, a recent study conducted by the California Office of Appropriate Technology indicates that the number of new firms entering the active solar field in California--the pacesetter state of the industry--is tapering off. Thus, it might be realistically concluded that there is a gradual maturation process under way, in which the characteristic solar company emerging from the recession will not only be older and more experienced, but will also average more installations, enjoy higher gross income, and typically be more diversified. Whether increased profitability will accompany this shift remains to be seen. In pinpointing trends and predicting future developments, it is also important to remember that most members of the industry still cite continuance of tax credits as a key to achieving stability and real growth in the active solar market.

STATE-LEVEL TRENDS

The active solar market is highly concentrated in a relatively small number of states. The top three states, California, Florida, and Arizona, accounted for over 52 percent of all installations in 1981. Installation activity in the top 12 states for 1981 is summarized in Table 3. These 12 states accounted for 82 percent of all installations in 1981. California, Florida, and Arizona

Table 3: The Top Twelve States

State	Number of Installations*				Ranking	
	Prior to 1980**	1980	1981	Total	1980	1981
California	49,513	39,661	41,131	130,305	1	1
Florida	27,000	19,395	15,454	61,849	2	2
Arizona	26,028	13,345	13,157	52,530	3	3
Colorado	1,489	1,600	6,122	9,211	11	4
Puerto Rico	410	3,646	5,171	9,227	5	5
Michigan	1,014	1,793	5,027	7,834	a	6
Hawaii	9,556	3,958	4,747	18,261	4	7
New York	3,344	3,499	4,223	11,066	6	8
New Mexico	663	686	4,145	5,494	a	9
Connecticut	1,815	1,422	4,029	7,266	a	10
Oregon	1,183	1,089	3,223	5,495	a	11
Massachusetts	1,802	2,492	2,641	6,935	7	12
Total	123,817	92,586	109,070	325,473		
All Other States	20,017	21,012	23,797	64,826		
Grand Total	143,834	113,598	132,867	390,299		

*Estimated totals based on survey data
**As reported by survey respondents in business in 1980
a--Did not appear in the top 12 states in 1980

ranked number one, two, and three respectively in both 1980 and 1981, as well as on a cumulative basis. Of these, California showed minor growth between 1980 and 1981, while activity in Arizona and Florida declined slightly. Significant growth occurred in Colorado, Connecticut, Oregon, and New Mexico, the last three states not being in the top 12 in 1980. State-level tax credits are believed to have played a key role in some of these states, particularly Colorado, which ranked number four in 1981. Michigan also recorded substantial growth, moving to number six in 1981. States that dropped from the top 12 in 1981 include Montana, Wisconsin, Pennsylvania, and Wyoming.

A review of the top solar states reveals some common themes. With some exceptions, these include favorable climates, large or growing populations, relatively high electric and natural gas prices or dependence on fuel oil, existence of state tax incentives, and the presence of government and private organizations actively promoting solar awareness. The dominance of these states is expected to continue in 1982 and probably beyond, though rapid decontrol of natural gas prices or a change in the current stability of oil prices could dramatically alter solar markets.

CONCLUSIONS

The marketplace was extremely receptive to active solar systems in 1981, generating almost $600 million in sales for the industry nationwide. Most of the installation activity was concentrated in the single-family sector of a few key states, with water heating applications dominating. The industry is still highly volatile, characterized by a large number of young firms, or firms with other business bases, doing a small number of installations each year. Turnover--companies entering and leaving the field--remains high.

This volatility creates negative images of the industry and makes consumers reluctant to buy solar energy systems. Many potential buyers still question the reliability of systems, and wonder if the installation company will be able to provide good service over the life of the system. Even though the collectors themselves may be certified, installation quality can vary significantly from one installer to the next. Those firms that are identified as large-volume installers and have been in the business a number of years appear to have overcome these credibility problems and are showing modest growth with more stability. This stability is viewed as a critical element in the long-term growth of the industry. Also considered essential by industry participants are the continuation of tax incentives and heightened public awareness of solar energy, coupled with effective consumer financing techniques.

In hindsight, 1981 was a good year for the active solar industry, with gross sales increasing 37 percent. But by the fourth quarter of 1981, when recession began to grip the economy, company managers could already see the approaching storm. The downturn has been sharper and lasted longer than anyone anticipated. As unemployment and interest rates climbed, the market for active solar energy systems dried up. Through the first three quarters of 1982 many solar dealers and installers have gone out of business; others are just treading water; almost no one is bragging about profits. Though no hard data are yet available, it seems likely that for the first time since the inception of the modern-day solar industry, 1982 will show only modest growth, if indeed it shows any at all.

SOLAR ECONOMY & TECHNOLOGY UPDATE

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Remembering Truman's observations about economists and how if you put them all head to toe they would point in different directions, I am not the least bit hesitant to offer my views on what the solar economics are today. There are really three perspectives from which to speak. One is the industry view. Another perspective is the nation's situation. And finally, and probably the most important, the consumer's solar economics.

Let's start with the industry perspective. 1981 followed a fairly good 1980. Thirty percent increase in sales resulted from a 30% increase in the number of solar installers. This fact demonstrates that the market is very much dealer/installer driven. The 30% increase in 1981 put total collector production in the neighborhood of about 20 million square feet. This was split about 50/50 between low temperature and medium temperature collectors. The bulk of the medium temperature collectors were sold for domestic hot water applications in the 120^{o}-140^{o} temperature range, and most of the low temperature collectors were installed swimming pool type applications.

Using a rough estimate of the cost per square foot of collector, the total installed value of the market in 1981 comes to about $750 million. 1982 results are not yet tabulated, but according to knowledgeable industry sources, it wasn't that great a year. In fact, it appears that there was about a 30% decline in volumes from 1981, which puts us in the $450-$500 million range for 1982. Significantly, we believe the interest rates, oil glut, and the fact that consumers were not very anxious about purchases of big ticket items hurt quite a bit in 1982. The strong support from the Reagan administration that nobody expected did not materalize, so we were not disappointed there. As an industry, we supported the Reagan cuts in DOE spending, and all in all suffered through a pretty tough year.

In that same year, as witness to the difficulties tha were endured, some major solar producers departed: Olin, Revere, and more recently, Sunworks announced that they are getting out of the market. The prior year Exxon exited. These were all big hitters that give creditability to an industry group that has about 400 manufacturers involved. Four hundred manufacturers that from year to year are very seldom the same manufacturers. There seems to be a core group of about 100. You recall that I said the number of installers in 1981 increased by about 30%. In that same year, we know that there was about a 30% attrition rate. So close to 60% of the participants in the solar market in 1981 were new kids on the block, and in the domestic hot water market, each averaged only about two systems per month installed. On a thumbnail basis, that is solar economics for the industry.

For the nation's perspective, I think there are some interesting observations that can be made. Solar is an extremely labor intensive product. In fact, about 60% of the installed sales dollar goes for labor. If you use any sort of reasonable multiplier on the effect of employment that the solar industry has provided, it can be quickly seen that well over a billion dollars worth of jobs have been created by solar. In considering the consumer and talking about economics for the solar consumer, I want to make a clear and concise statement. There is all this debate on what are the solar economics. With clear authority I can say, "it depends". It depends on the equipment, the application, where it is placed, what the alternative fuels cost, shading, and so on and so forth. But the performance depends, even with the greatest servicing. It is only going to be so much and it is going to vary.

Typically, and let's take Washington, D.C. as the Bre basket of America, you would be looking for returns to the consumer in the neighborhood of three to seven years considering the tax credits, against electricity. Against natural gas, the returns are considerably longer. But really, this kind of begs the question for the typical consumer who is interested in "what's it going to cost me a month". What's the effect? Most folks, me included, don't have $3500 that they can reach in their back pocket, throw on the table and buy solar equipment. You finance it. With interest rates coming down, the way it works out is that you can buy a solar system, finance it and not be one cent out-of-pocket. In fact, at the end of the first year, you will be in the neighborhood of $1000 in-pocket thanks to the tax credit. How does it work? Fairly simply. There is a 40% tax credit for solar. Forty percent of $3000 is $1200. Your financing charges for that first year will be maybe $300-$400. Take that and subtract your fuel savings and supplement it with your tax credit and you are in-pocket with the amounts I indicated. Solar economics for the industry have been fairly dismal. Solar economics for the country and the consumer are pretty good.

When talking about the application of technology, I look at areas that have more meaning to me as a marketer of solar equipment. First, where we stand as an industry. DOE has essentially deserted the active solar areas in which I am participating. They are supporting solar and photovoltaic electricity from the sun, but the medium temperature collector range is not particularly attractive to them. They are moving towards what they call core technologies. What this means is high risk, high return R&D that the companies will not do themselves. With the exit of Exxon, Grumman kind of idling, Olin gone, Sunworks gone, and so forth, I am not sure who the companies are that are going to do the R&D, because considering the participants left in solar energy . . . well, Sam's Hardware typically does not have the labs to do solar R&D, and that is by and large what constitutes manufacturers that are left. Nonetheless, there is some interesting solar R&D work that is being addressed.

The first is DOE spent hundreds of millions of dollars on solar R&D and nobody knows what the results were. It is all carefully documented in some pile in Lithuania or some place. The Solar Energy Industry Association is actively working with DOE and DOE is actively working to move this technology off the shelf and into the marketplace where it can be used. There are people who need and can use and can turn products into the sort of data I don't understand. Another area that is being pursued is R&D done by the Gas Research Institute. For example, products that may come from their work include desiccant heat pumps, chillers and air conditioners. The technology used in such products is essentially the same used in a swamp cooler, where air is blown through moisture and cools down. The only problem is you have moisture laden air. The trick is to use desiccants to remove the moisture without putting heat in. A natural application for solar is its use to dry the desiccant out. The major difficulty has been one of obtaining enough absorptive ability to be able to work at a modest cost. Exxon, before they exited, had done some fairly interesting work on a desiccant wheel. GRI has picked up on this technology and is continuing in a similar effort.

Another technical area that could be fairly significant to this industry is the work on polymer collectors. These have the promise of significantly reducing the cost of solar equipment. Promises, but no guarantees, and it is not something that Sam's Hardware or Acme Solar is going to be able to do. It takes support. But these are some things to be very hopeful about and to raise expectations in the solar technology market of medium temperature applications.

On the broader horizon is the thermal area. Thermal here is defined as higher temperature applications, applications where temperatures are reached that can fire turbines and produce electricity. The power tower has been dedicated. This is the project where heliostats computer-aligned with the sun were directed at a spot on the tower. The heat generated was used to produce steam which turned the turbine producing electricity. It works. I don't expect that every local community will be installing their power tower anytime soon, but it is a technology that works.

Parabolic collectors that provide higher temperatures are being used in industrial process heat applications producing steam. So, there are areas where what was wished at a few years ago is now practical and in the market. We have definitely taken a step back in the pursuit of the R&D, but if we can just pick up a couple of these nuggets such as the desiccant cooler or the thin film or polymer collector, significant inroads can be made in our nation's energy needs.

PARABOLIC TROUGH TECHNOLOGY AND ECONOMICS

Gus Hutchison

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The concept of converting solar energy to high temperature, quality heat is not a new one, however, in recent years it has been developed to a very efficient and cost effective state. Among the several concentrating collector generic types, the parabolic trough stands out as possibly the most cost effective for medium and high temperature applications. See Figure 1.

The basic process by which the parabolic trough collector converts sunlight to usable thermal energy is a simple one. When direct beam solar radiation enters the aperture of a parabolic-shaped mirror, the surface is such that the reflected light is directed to a point at the focus of the parabola. See Figure 2. In the case of a parabolic trough, the focus is described as a tube, and the reflected light is focused on the bottom half of this receiver, or absorber tube. Current production units have geometric optical accuracies in the area of 97% with reflectives up to 94%. This high percentage of net solar radiation is absorbed onto the receiver tube which is coated with an optically selective surface which captures approximately 97% of the sunlight striking the tube. A small amount of light is lost as it passes through the glass tube which surrounds, insulates and protects the absorber, or receiver tube.

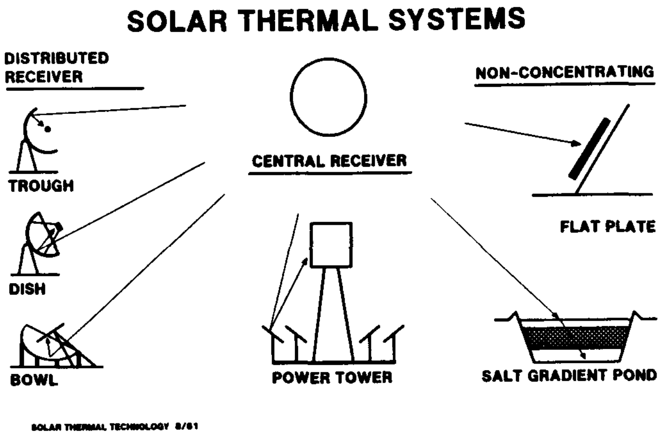
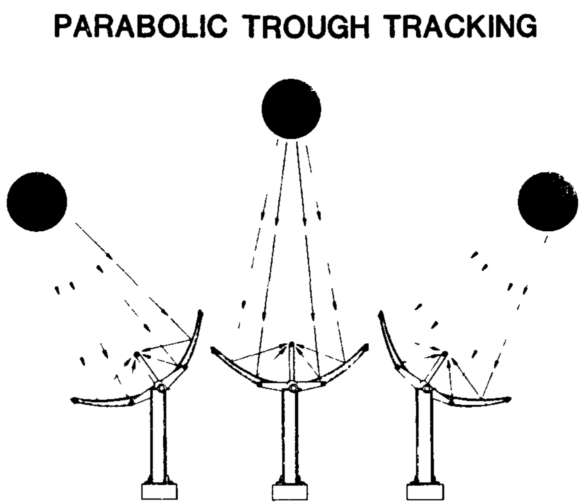


FIG. 1



From dawn to dusk — Light sensitive tracking motors keep concentrating collectors in direct line with the sun throughout the day

FIG.2

Net optical efficiencies of current production solar collectors vary from 70% to 82%. In other words, current production collectors are capable of capturing and delivering up to 82% of the sun's energy as usable thermal energy at temperatures close to ambient.

As the receiver is heated to temperatures well above ambient temperature, thermal loss occurs in the form of conduction, convection and radiation. Since the absorber area is small relative to the solar collector aperture, the thermal losses are small in comparison to such collectors as flat plates. This enables the parabolic trough collector to operate at high temperatures. Material and heat transfer fluid limitations prevent current production equipment from exceeding 600°F.

Collectors with high optical concentration ratios require tracking of the sun since such collectors can only use direct, focused radiation. Current production parabolic trough collectors vary from seven to ten feet in width and twenty feet in length with up to six mirrors being installed in one trackable row. A central drive and tracking unit causes the six mirrors to rotate about an axle, down the trough of the collector, allowing the system to focus on the sun at any point in the sky. At night, the mirrors are inverted to the "stow" position to protect the mirror from hazardous conditions and to reduce soiling of the mirrored surface. When the dew forms in the early morning hours, it does so on the back surface of the mirror allowing the parabolic trough to remain cleaner for longer periods than non-tracking collectors. The collector drives usually operate at a high speed to acquire the sun then at a very low speed during the tracking phase. Pointing or tracking is usually accomplished with analog electronics or digital synthetic tracking control systems. All collector drives are usually commanded by a central controller which includes a small microprocessor. Such weather sensors as light switch, wind switch, rain switch, over temperature switch and flow switch are included. These sensor inputs provide the central microprocessor with the information needed to determine if the collectors should be pointed to the sun or in the stow, protected position.

Parabolic trough collectors are usually mounted horizontally, although mounting on south facing slopes is possible. Unlike non-tracking, non-concentrating collectors, the parabolic trough can be mounted at any azimuth angle. The collectors need not be facing south or east and may be attached to the roof of a building, square to the building and providing the most architectually pleasing arrangement. The 260° angular acquisition capability of most parabolic trough systems allows focus on the sun at any angle and facilitates mirror cleaning and other maintenance activity.

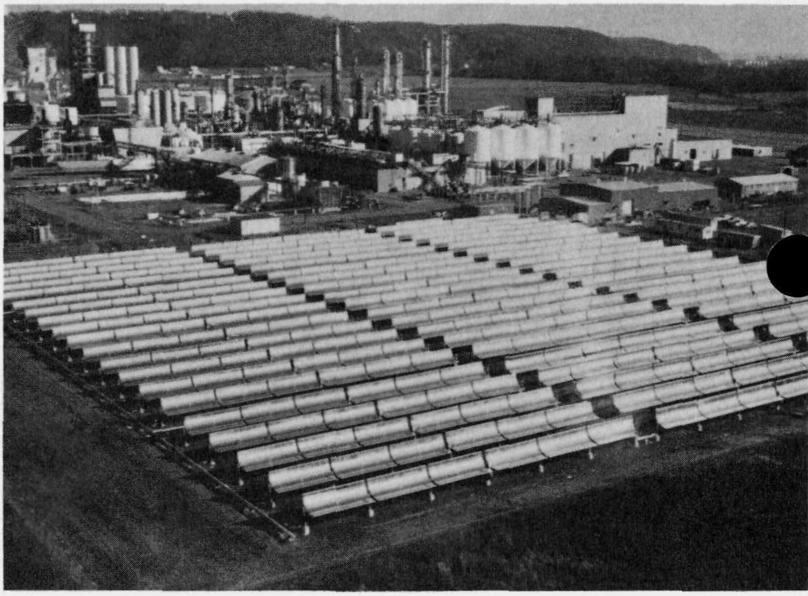
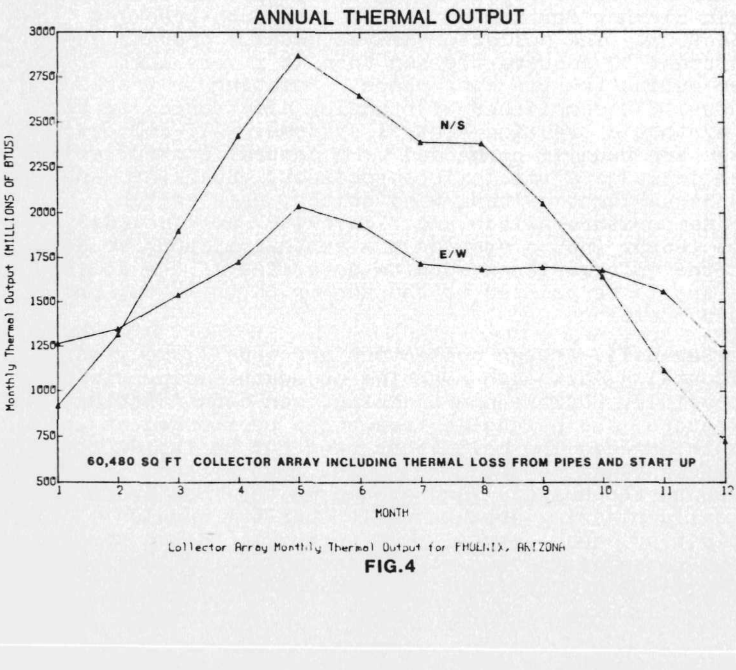


FIG.3



Collector Array Monthly Thermal Output for PHOENIX, ARIZONA

FIG.4

Depending on seasonal cloud cover profiles, the north-south collector axis orientation delivers slightly more energy on an annual basis than the east-west (north-south tracking) array. These two orientations deliver symmetrical daily output profiles with all other orientations producing curves which favor either the morning or afternoon periods. Generally, the east-west orientation delivers about the same daily energy through the year, while the north-south collectors produce most of the annual energy during the summer months with lower levels of delivered energy during the winter. See Figure 4. Relative solar angles account for most seasonal and orientation output variations since ambient temperatures do not markedly affect parabolic trough performance. Collector field orientation should be designed to provide seasonal output profiles which follow load profiles, where possible. For example, where air-conditioning is the greatest single load, a north-south array is usually preferred. This matches the collector's seasonal output to the seasonal load requirement.

The gap between rows of collectors varies with land or building usage, but may affect performance due to shadowing of one row by another. This generally is the case with any solar system. Row gaps of three times the width of the collector will effectively eliminate shadows during usable solar periods, but in some cases smaller row gaps of as little as two mirror widths may be effective. See Figure 5.

The usable thermal energy is extracted from the collector using a heat transfer fluid. Many different fluids have been used in parabolic trough collectors to provide energy transfer from the receiver to the load. These include: Treated water, water/glycol, heat transfer oil and silicon oil.

Low ambient temperature is usually the most influential factor in choosing the correct heat transfer fluid. Obviously, freezing temperatures dissuade the use of pure water. Glycols may be used to depress the freezing point, but maintenance of water chemistry is problematic and water/glycol solutions are generally limited to 300°F operation with high degradation rates for this temperature level.

Steam generating systems generally use a closed loop for the heat transfer oil, but boiler feedwater may be circulated through the collector field under pressure, and then flashed at the point of use. Pumping the water at high pressure causes very high parasitic pumping losses and closed loop systems using heat transfer oils are usually the preferred design.

COLLECTOR FIELD LAYOUT

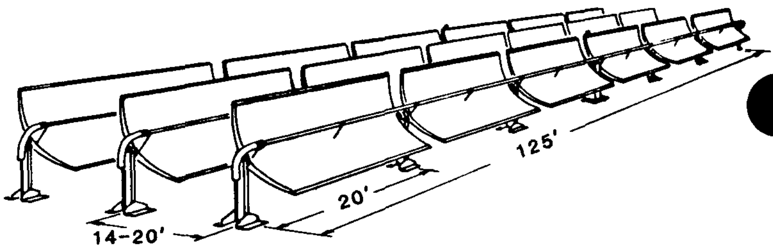


FIG.5

COLLECTOR FIELD FLOW SCHEMATIC

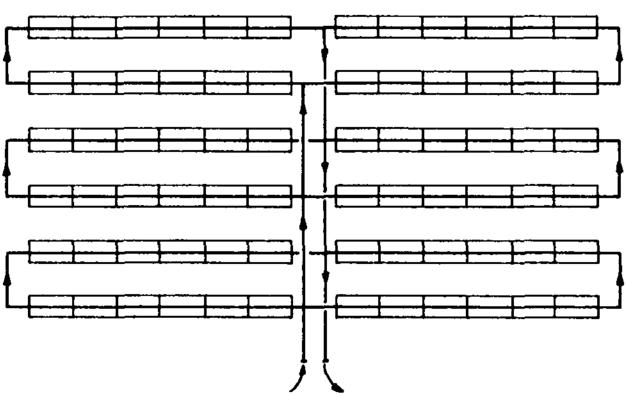


FIG.6

When temperatures exceed 300°F, and for the lower temperature systems as well, heat transfer oils such as the Therminol series by Monsanto, or the Caloria series by Exxon, or the Dowtherm series of oils by Dow have been used quite successfully. These oils are capable of operation at 600°F, but most exhibit high viscosity at very low ambient temperatures. Pump startup in very cold ambient temperature locations may be a design problem, but some of the oils, such as Therminol T-60 or Syltherm 800, have good practical low viscosity characteristics.

Heat transfer oils are all flammable with flash points in the 400°F range, but this usually doesn't pose a design problem for ground mounted, closed-loop systems.

The parabolic trough collector can compete, in terms of annual energy output, with flat plate collectors, for applications as low as 150°F. While the flat plate system can use all available sunlight, including both direct normal and diffuse sunlight, the parabolic trough intercepts more direct sunlight per year due to tracking, and the very high efficiency coefficient of the concentrating collector delivers more net energy on an instantaneous basis from direct sunlight. For temperatures above 180°F, the parabolic trough system usually is the design choice.

For some very large industrial process heat projects, central receiver systems may compete well with parabolic troughs. For temperatures above 600°F, a central receiver system is the most practical choice with parabolic dishes still being somewhat in the developmental stage.

There are several basic types of energy loads which are currently being addressed by parabolic trough systems. They include: Air-conditioning-space heat-hot water, process hot water, process steam, process drying and electric power. In each case, the heat transfer fluid is circulated through the collector array causing an increase to the fluid temperature. See Figure 6. Figures 7-11 indicate the basic flow schematics for each of the systems. In most cases, the solar fluid handling and control equipment is skid mounted, including the heat transfer fluid pump, heat exchanger or boiler, control valves and weather sensors.

When 24-hour operation is desired and sufficient land is available, a larger array is installed and the excess energy produced during the daylight hours is stored as heated transfer oil for use at night. The skid-mounted control system will pump the hot oil to

SOLAR PROCESS DRYING SYSTEM SCHEMATIC

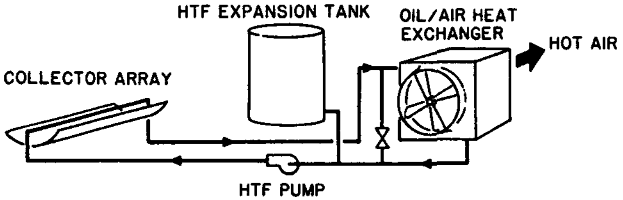


FIG.7

SOLAR PROCESS STEAM SCHEMATIC

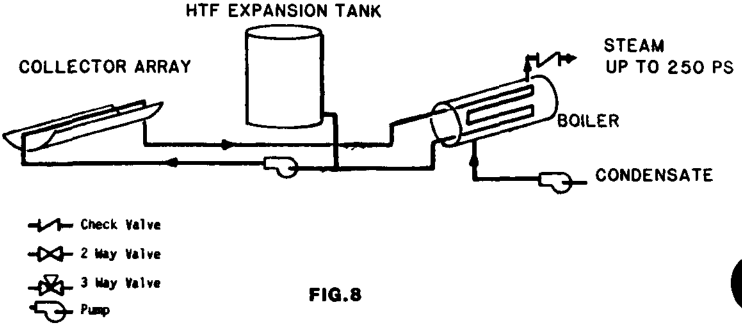


FIG.8

SOLAR PROCESS HOT WATER SYSTEM SCHEMATIC

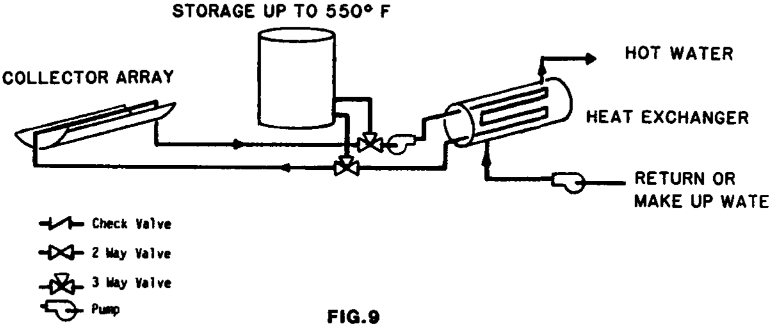


FIG.9

SOLAR HEATING AND COOLING SYSTEM SCHEMATIC

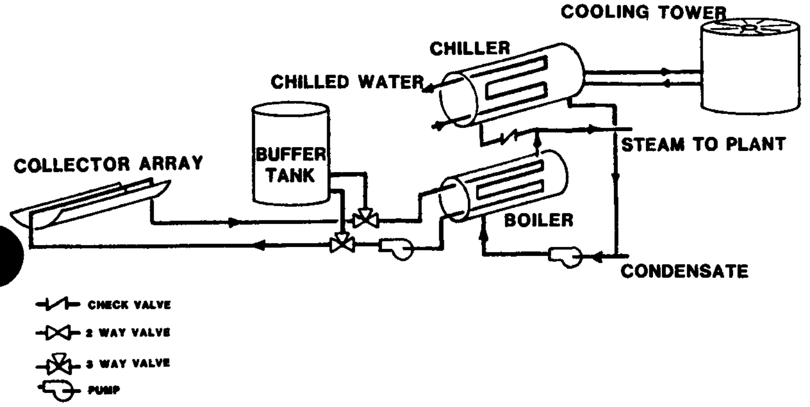


FIG.10

SOLAR POWER PLANT SYSTEM SCHEMATIC

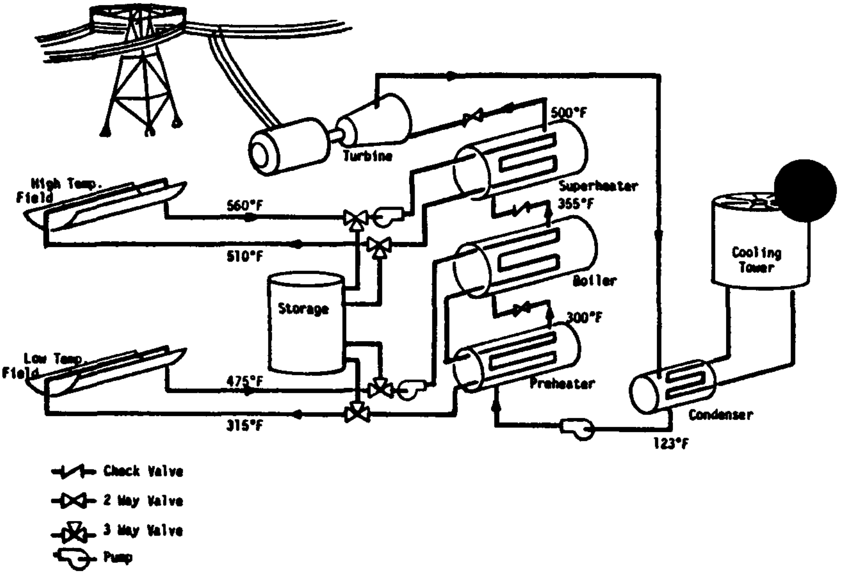


FIG.11

APPLICATIONS OF PARABOLIC TROUGH COLLECTORS

USER/SITE	ARRAY SIZE	THERMAL LOAD
Dow Chemical Dalton, GA	10,000 sq. ft.	150 psi steam
Control Data St. Paul, MN	25,000 sq. ft.	Heating/A.C.
Johnson & Johnson Sherman, TX	11,000 sq. ft.	15 psi steam
Irrigation Project Coolidge, AZ	22,000 sq. ft.	Electricity
U.S.S. Chemicals Haverhill, OH	50,400 sq. ft.	80 psi steam
Lone Star Brewery San Antonio, TX	10,000 sq. ft.	125 psi steam
Mississippi County Community College Blytheville, AR	38,800 sq. ft.	Heating/A.C.

Fig. 12

and from the storage tank, allowing operation into the night. Since the heat transfer oil has an upper temperature limit, such storage systems are far more efficient for lower temperature applications.

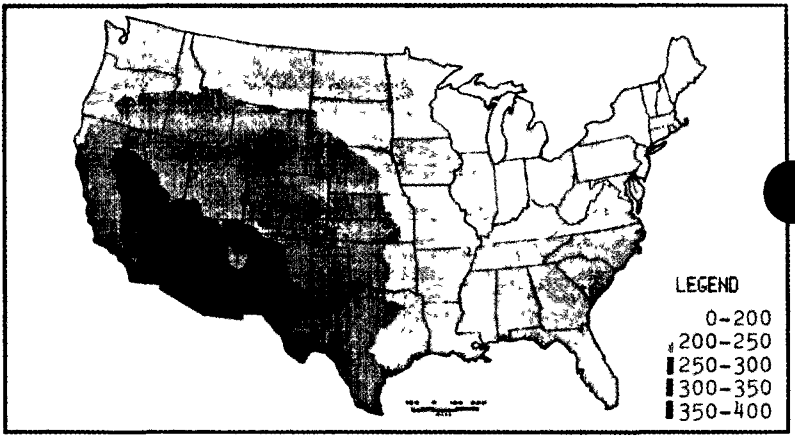
The concept of using parabolic trough solar collectors to deliver usable thermal energy is not a new one. The first well documented use of such a system took place in the late 1800's as a solar-powered irrigation system. Since then, low cost energy has curtailed consideration of solar concepts for development until recent years. The latest development of the same basic concept has given rise to very efficient and practical solar systems. Figure 12 is a chart showing a sampling of the industrial and commercial applications of parabolic troughs showing size, operating temperature, load and date of initial operation.

The economics of a solar parabolic trough collector system vary greatly with specific applications. Some of the variables which are involved are: Cost of fossil fuel, boiler efficiency, cost of land, availability of roof space, distance from collector array to load, geographic location (available sunlight) and state taxes and/or credits.

Figure 13 is a map indicating the variation in available output for parabolic troughs throughout the United States. The dark areas are high thermal output areas, as noted. The states of California, Colorado, Arizona and Oklahoma currently have tax credit for solar installations for industry and most economically attractive applications are found within these states. See Figure 14. Figure 15 is a summary table of potential parabolic trough applications for these four states showing ranges of system cost, collector system energy outputs, state tax credits and return on investment.

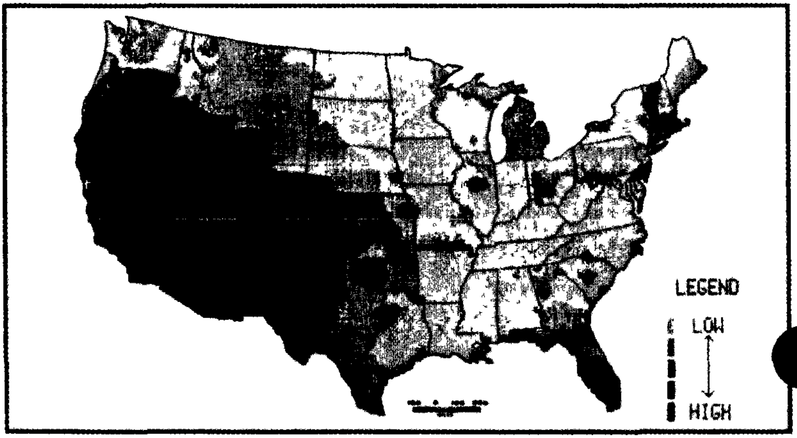
For new technology applications, such as solar, industry has historically required a rate of return which is higher than its normal process equipment investment hurdle. Many corporations will consider a 25% ROI, but the 30% to 50% range is perceived to be minimum for a new technology investment such as solar. Except for situations with exceptionally high fossil fuel costs, only the four states mentions in Figure 15 deliver these rates of return.

When an industrial user cannot justify a major capital expenditure, regardless of payback, or if the user does not have sufficient tax liability to take advantage of all credits and depreciation, an alternate financial concept is proposed. Many parabolic trough



PARABOLIC TROUGH ANNUAL AVERAGE THERMAL OUTPUTS

FIG.13



PARABOLIC TROUGH SOLAR ATTRACTIVENESS INDEX

FIG.14

TYPICAL SOLAR APPLICATIONS

RELATIVE ECONOMICS

State	AZ	CA	CO	OK	TX
Gas $/MCS	5.00	5.50	4.50	4.80	4.50
Collector Output MBTU	360	330	280	250	300
State Tax Credit	35%	25%	30%	30%	-0-
Disc. R.O.I.	+100%	38%	33%	27%	17%

Fig. 15

manufacturers are offering "third party" ownership for systems. Under this plan, the energy user leases the land necessary for the collector array, at a nominal price, to the system owner. The collector manufacturer engineers and installs the system at the user site, sells the system to the third party, and the third party then sells the energy produced by the collector system to the user at a discount rate over the ongoing cost of fossil generated heat. This plan allows the energy user to begin to save on the cost of process heat immediately, and, at the end of the energy purchase contract, should the user purchase the equipment at the then fair market value, even greater energy savings can be achieved.

While third party owners may or may not require the same rate of return on such an investment, it is clear that only the four states mentioned above provide sufficient payback for widespread use of the concept. An increase in the federal tax credit for solar applications would enhance the viability of other states which have marginal economics for such applications. An extension of current tax credits would allow sufficient time for energy prices to escalate, within these states, to a point where solar systems would be economically attractive to most industrial users.

Parabolic Dishes: Technology and Economics

Daniel J. Shine Jr.
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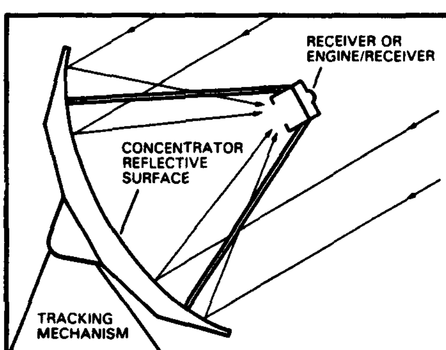
Nashua, N.H.

I welcome the opportunity to discuss the status of Parabolic Dish Technology and Economics and the need for a continuation of federally-sponsored RD&D in renewable energy technologies.

Federally-sponsored RD&D is needed, particularly in Parabolic Dish Technology, if the U.S. is seriously to pursue the goal of reducing oil imports and achieving some measure of energy independence within the next decade.

An illustration of a typical Parabolic Dish system follows.



Parabolic Dish Technology

Parabolic Dish Systems are one of several Solar Thermal Concentrating Technologies under development. This type of system consists of a dish-shaped parabolic concentrator that focuses the sun's rays on a receiver (or absorber). The receiver is mounted above the dish at its focal point. Sunlight is focused on an opening in the receiver to heat a fluid or gas circulating through the receiver. The hot fluid can be transported to the ground for a variety of thermal uses, or direct electrical generation can be accomplished by integrating an engine/alternator with the receiver at the focal point.

With an engine/alternator mounted at the focal point, each dish can be a complete power-producing unit (module), which can function either as an independent system or as part of a group of modules linked to form a larger system. A single parabolic dish module can achieve fluid/gas temperatures from 300° to 1500°C and can efficiently produce up to 25 kW of electricity. Technical issues presently being addressed are summarized below for the five principal dish subsystems.

Concentrator. The largest subsystem of a parabolic dish module is the concentrator, a shallow dish with a reflective surface that tracks the sun to focus sunlight on a receiver. Tracking along two axes ensures maximum solar energy collection during the day. Several concentrators have been developed in this century. Seven and eleven meter concentrators built and of particular note are successfully tested under DOE and/or industry sponsorship in the past few years.

The conventional optical configuration for a dish concentrator is a paraboloidal mirror. The paraboloidal shape may, however, be segmented into a number of individual reflecting facets, which may be curved or flat.

The ability to reflect and focus sunlight is a principal consideration in selecting materials and designs for dish concentrators. The classical optical material used is back-silvered glass. Reflective materials typically must be curved, the exact shape of the facets dependent upon the design of the concentrator. Materials other than glass, e.g., aluminum or aluminized mylar, can be shaped more easily, but such materials have lower reflectivity than back-silvered glass. Other technical questions being addressed are bonding of the concentrator layers, degrading of surface materials in the outdoor environment, and decreasing concentrator weight and cost while maintaining strength.

Receiver. Because the receiver absorbs concentrated solar radiation at very high temperatures (>2000°F), receiver materials must be developed that can withstand these and the potentially higher operating temperatures (up to 2700°F) of future dish systems. Several types of receiver have been developed and tested by DOE and industry since 1976. Additional research and development activities will concentrate on minimizing heat losses through the receiver opening (aperture).

Engines. Three types of heat engines are being tested for use with parabolic dishes: Brayton, Rankine, and Stirling. Heat engine designs for solar-thermal-to-electric dish applications must be adapted for use in different attitudes due to the varying sun angle from sunrise to sunset. However, key development issues are the achievement of high engine performance and reliability, and identification of operating requirements at the interface of the engine and receiver.

Storage. For dishes providing thermal energy, periods of direct solar operation can be augmented by the addition of a thermal storage system. The storage media that has been most researched consists of oil/rock mixtures for use with the in Rankine engine. Buffer storage (up to 1 hour) and intermediate storage (1 to 6 hours) can provide energy for dish systems during dark periods. Dishes operating in the Brayton or Stirling mode can be fitted with short-term thermal storage capacity (between the heat engine and receiver). The storage media will typically be a solid with high surface to volume ratios, e.g., ceramics, most frequently in a honeycomb configuration, when a Brayton or Stirling engine is used. These engines can be operated in a hybrid mode, where the engine runs on fuel, either fossil or renewable low BTU gas from biomass conversion, when sunlight is inadequate, providing a continuous source of electricity.

Controls. Dish systems track the sun in two axes. Each dish in a collector field is adjusted individually to ensure that the optimal amount of sunlight is being focused on the receiver opening. This requires the use of a computer-based active tracking mechanism to determine and maintain accurate alignment. Additionally, the control must regulate the engine/alternator in response to changes in the load requirement. This can be handled by appropriate modulation of the energy supplied by the Solar Receiver and/or the burner in a hybrid system. Other safety, and start-up/ shutdown functional considerations must be automated.

The foregoing provides a short descriptor of the technology issues being pursued today.

Sanders Associates and Sanders Solar Programs

Before presenting my views on a logical Parabolic Dish Program for the next few years, it would be appropriate to define briefly my company's past and proposed future role in the program.

Sanders Associates, Inc. is primarily engaged in the development, manufacture and sale of advanced technology electronic systems and products. Sanders conducts business in two principal industry segments, Government Systems and Products and Graphic Systems and Products. Sanders 1982 sales exceeded $435 million.

Sanders Government Systems and Products business includes defense electronics, component products, renewable energy systems products and international systems. The largest of these is defense electronics where Sanders is a leading producer of electronic and infrared countermeasures for aircraft self protection. Other defense markets include signal processing, ocean surveillance, air defense, training and simulation, and automatic test equipment.

Sanders has been part of the Solar Thermal R&D community since 1976. The company's principal effort in Solar Thermal has been in the development of high temperature receivers for Parabolic Dish and power towerapplications. Sanders has been awarded slightly over $5M worth of R&D contracts by DOE since 1976 and has spent somewhat over $1.5M of its discretionary resources on development of the technology over the same period. Sanders is presently under contract to DOE, through the Jet Propulsion Laboratory, to serve as systems integrator for an advanced technology 8 KW_e Parabolic Dish Brayton Power System which we expect to have operating during Calendar 1984.

Sanders has not yet entered the commercial marketplace with its equipment, and estimates that it is about three years from such entry.

Parabolic Dish System Benefits

Sanders Associates has concentrated on the development of Brayton engine powered Parabolic Dish Systems for a number of reasons, among them the following:

1. The Brayton Powered Solar Electric System promises to provide the lowest cost per delivered kW/hr compared with other systems;

2. Brayton engine technology is simpler mechanically than Stirling and Rankine technology;

3. The use of the advanced Brayton engine provides the highest (35%-45%) conversion efficiencies;

4. The Brayton uses ordinary atmospheric air where as the Stirling must use high pressure hydrogen or helium and the Rankine uses either water or an organic fluid;

5. Unlike the Stirling and small Rankine, the Brayton is currently being developed in appropriate sizes for Parabolic Dish applications, independent of the Solar Program for high volume commercial applications;

6. The modular nature of Parabolic Dishes grouped in farm-like clusters provide four powerful advantages to private industry in reaching commercialization:

   a. Only a small number of successful prototype modules need to be taken to proof of concept rather than to any large multi-megawatt scale;

   b. The ability of each module to be incrementally brought on-line permits short lead time on construction, negligible interest used during construction and rapid placement into a users rate base;

   c. Mass production benefits occur earlier and at a lower power market level due to the modularity of the 10-3 kW systems; and

   d. Additional modules can be added to farm-like clusters to meet the user's incremental power demand growth;

7. The minimal cooling requirements of the Brayton engines uniquely permit operation in the high insolation, arid regions of the U.S.

8. Multimodular systems permit routine maintenance and/or repair with only a partial output reduction.

The Present Situation/Federal Role to Date

In my opinion, over the past six years, DOE has proven to be a rather effective technology development broker. The program Sanders is now pursuing under DOE auspices utilizes advanced technology components developed by a variety of industrial organizations under DOE and Jet Propulsion Laboratory sponsorship. Component demonstration programs have been very successful to date, clearly justifying the cost. These demonstrations have taken place primarily at Government owned and/or operated sites, utilizing facilities that industry would not or could not duplicate. No single company or industry could justify on a private use basis the JPL, U.S. Army, DOE, and Sandia operated Solar Thermal facilities which have been critical to the development of Solar Thermal Technology; specifically the Army White Sands site, Sandia's Albuquerque and Livermore sites, and JPL's Edwards Air Force Base test facility.

Future Federal Role

Relative to the future Federal role, I believe that the Government should continue to support programs which will prove new technology at both the component and systems levels. Although many component development/demonstration programs have been highly successful, a true commercial market will not emerge until systems level testing over an extended period of time (12-24 months) has taken place. The reduced Federal role of recent years has delayed commercialization, particularly related to more advanced technology systems. Investors in the private sector are unwilling to supply needed capital until full systems tests have been completed. Further, in the Parabolic Dish System case, JPL has been the technology transfer medium. Withdrawal of DOE/JPL support will significantly reduce data flow between companies, as each component developer seeks to maximize his position vis-a-vis development of a system. Without a broker, technology development which is in the nation's long term strategic interests could be delayed.

Summary/Recommendations

The President's Domestic Policy Review (DPR) Board recommended a national goal of three quads (quadrillion BTU) for Solar Thermal Energy by the year 2000. I believe that a Congressional directive to the Department of Energy (or its successor agencies) to strive toward this goal would greatly enhance the prospects of commercializing Parabolic Dish Systems which could provide up to 1 quad of the 3 quad goal.

Over the past several years, DOE has been promoting what I perceive as an eight step program for advancing Solar Thermal Technology. Unfortunately, we are now stuck in the initial stages of Step 4, with little prospect for moving on. The eight steps are

1. Basic and applied research
2. Market research - perception of user requirements
3. Component development
4. Advanced System development and test
5. System engineering and field test
6. Test marketing - user test
7. Initial production of units and subsequent distribution
8. Sales and marketing

When a program moves beyond Step 4 and Step 5 to Step 6, cost sharing by contractors can logically be required by the Government. Until that time, very few if any component developers will be willing to invest substantial sums, not because the developers do not believe in the potential of the technology, and the related economics, but because the Return on Investment (ROI) requirements dictated by today's interest rates almost preclude long term high risk investments by publicly held companies. It is my belief that a 3-4 year commitment of $15-20 million per year to the Parabolic Dish Program will bring us to the point where industry and the financial community will be willing to invest substantial sums in commercializing a technology which could eventually save the U.S. 170 million barrels of oil per year.

In sum, I recommend Federal support of the Parabolic Dish Program at the $15-20M a year level through at least FY85-86. With such support, Parabolic Dish Technology can be fully tested and proven ready for commercialization. Cost sharing by industry in the latter stages of this program should be required. With this level of support the parabolic dish solar thermal community could well supply upwards of 1 quad of the nation's energy requirement by 1995-2000, displacing the equivalent of 170 million barrels of oil per year.

Daniel J. Shine, Jr. is Business Development Manager of Sanders Associates Defense and Information Systems Division. Sanders is a major defense electronics firm located in Nashua, NH. The Company has been involved in Solar Thermal research for several years. Sanders has designed, built, and tested several solar thermal components for DOE, the Jet Propulsion Laboratory and Sandia Livermore since 1976 and is presently acting as systems integrator and high temperature receiver supplier in the Jet Propulsion Laboratory's Brayton Turbine Parabolic Dish Module Program.

Mr. Shine is a Founder and Board Member of the Solar Thermal Energy Division of the Solar Energy Industries Association and is presently Chairman of the Division's Point Focus Committee. Prior to joining Sanders in 1976, he spent ten years in the Federal Government in various technology evaluation positions. Mr. Shine is a graduate of Merrimack College, North Andover, Massachusetts and holds an MS from Georgetown University's Graduate School of Foreign Service.

NEW TECHNOLOGY ACHIEVES SAVINGS THROUGH SOLAR COOLING

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OVERVIEW

Currently under construction at the Veterans Administration Hospital in Washington, D.C., is the first application of new technology that uses solar energy cost-effectively in the summer cooling process. Included is a monitoring system to establish operational data for the prototype installation. Other applications in different configurations are planned for the Science Museum of Virginia and the Monroe County Government Center in Pennsylvania. This paper describes the principal features of the techniques; alternative energy-integrated air-conditioning system arrangements based on the new approach; and the VA Hospital application.

The key development is a desiccant dehumidification system with (a) the ability to dry the moisture-absorbing desiccant with low-grade solar energy (130-140°F); and (b) a heat recovery technique that significantly increases the COP* of the desiccant regeneration (drying) process. The ability to use low-grade heat for desiccant regeneration has two important consequences: Solar heat at the required temperature is available from flat plate collectors during

*Coefficient of performance. Increased COP=less purchased energy to perform a given amount of work.

most of the cooling season (about 80% of the time in the Washington area); and recoverable "waste" heat, including cogenerated heat, can augment solar energy to further reduce purchased energy consumption. The heat recovery technique on the desiccant regenerator enhances the practicality of solar regeneration by reducing the collector area requirement.

This core development--a more energy-efficient desiccant dehumidification system which can use low-grade solar heat as the primary energy source--greatly increases the options for energy-efficient and cost-effective design of the total, integrated air conditioning system for the following reasons:

- Dehumidification (latent cooling) is removed from the refrigeration system. Since the latent cooling task represents a significant portion of the summer load on the chiller in a typical refrigeration system (20-50%), this shift reduces purchased energy consumption as well as the size of refrigeration equipment.

- The refrigeration system can operate at a higher temperature level, which increases the refrigeration COP and reduces energy costs, because-
  (a) there is no requirement to chill to condense out moisture (since dehumidification is by a moisture-absorbing liquid desiccant);
  (b) the remaining function of the refrigeration system--cooling for sensible temperature control--can be performed at a higher temperature level.

- The quantity of air distributed can be reduced to the minimum required for ventilation (0.1 cfm/ft^2/h in office facilities)--and the costs for ductwork and fan power reduced proportionately--based on the following:
  (a) The air is dry enough, after desiccant dehumidification, to enable this minimum quantity to handle the humidity load in the space.
  (b) A piping network circulates high-temperature chilled water (55°F instead of 42°F) to fan-coil terminals, which handle sensible cooling. (One advantage of a piping distribution network--over the larger ductwork of an all-air system--is greater flexibility to adapt to changing facility use: Fan-coil units can be plugged in where needed, without the space and cost problems associated with new ductwork.)

- Recoverable waste heat throughout a facility can be integrated to support solar desiccant regeneration. (Sources include heat from the desiccant conditioner via a heat pump, and jacket and exhaust heat from a gas or diesel engine/generator set which simultaneously produces electricity (when heat is needed) to power the chiller, fans and pumps. The cogeneration system also serves as a standby power source in case of emergency.)

- Based on the larger number of usable, non-utility energy sources with desiccant dehumidification, a selective-energy system can effectively minimize utility energy consumption and operating costs, by using other sources optimally before switching to utility energy.

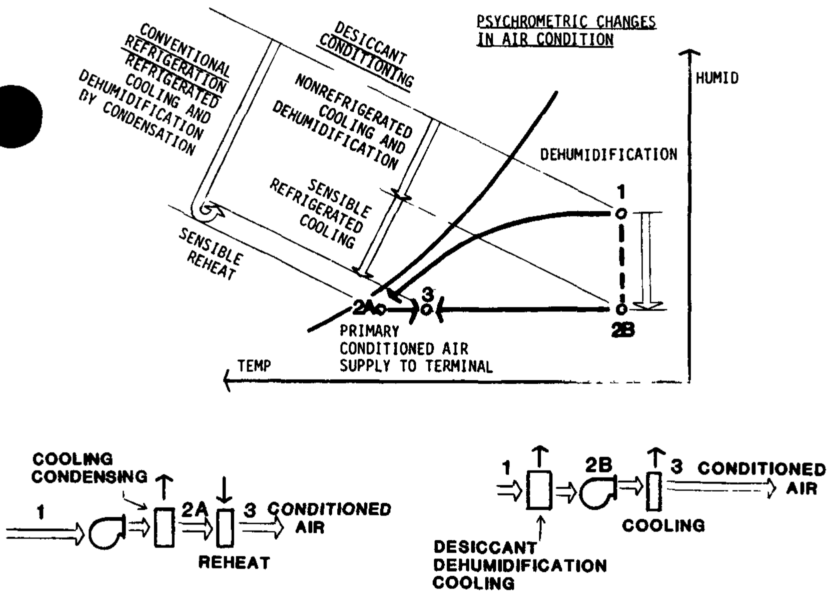
Other solar cooling technology to date has required solar heat of at least 200°F, since the solar energy has been used to power absorption refrigeration equipment. For that purpose, expensive evacuated-tube or tracking-concentrating collectors must be used--a requirement that has severely limited the practicality of solar cooling. By contrast, the cost-effectiveness of the solar desiccant dehumidification approach described in this paper stems from two factors: (a) low-temperature desiccant regeneration and (b) the greater scope for efficient design overall when sensible cooling is handled separately from latent cooling/dehumidification.

DESICCANT VS. REFRIGERATION DEHUMIDIFICATION

Air conditioning controls both the humidity and the temperature in a space. The method used to remove moisture affects the options available for heat removal (sensible cooling).

When dehumidification is by condensation, as in a conventional refrigeration system, the air is chilled to a dew point to condense out the moisture. Typically, 42°F chilled water is used. Sensible cooling occurs simultaneously. However, the air is overcooled in terms of the sensible temperature requirement. It must be reheated or mixed with warmer air prior to supply to the occupied space. Figure 1 illustrates the process psychrometrically: 1 to 2A shows the simultaneous lowering of the humidity and temperature levels through chilling to the dew point; 2A to 3 shows the return to a higher temperature for supply.

This process is contrasted with the desiccant dehumidification process in Figure 1: When a desiccant is used, moisture is absorbed by the desiccant and the humidity level lowered (1 to 2B) independent of sensible cooling. Subsequent sensible cooling by refrigeration (2B to 3) is to the required temperature only (higher-temperature cooling), with no need for reheat. Thus energy efficiency is increased based on Second Law thermodynamic techniques: using the highest-temperature cooling medium possible to achieve a given result, and using the lowest-temperature heating medium. That is, the temperature of heating and cooling mediums should be as near as possible to the required conditioned temperature.



CONVENTIONAL REFRIGERATION USING CHILLED WATER COOLING AND DEHUMIDIFICATION PLUS REHEAT.

DESICCANT DEHUMIDIFICATION PLUS SENSIBLE COOLING.

Fig. 1. Psychrometric Profiles:
Refrigeration vs. Desiccant Dehumidification

DESICCANT DEHUMIDIFICATION PROCESS

Desiccants are of two types, liquid or solid. Only liquid desiccants are discussed in this paper, primarily because a lower-temperature heat source can be used to regenerate (dry) the desiccant for re-use. In a desiccant system humid air is dried as it moves through or over a desiccant which absorbs moisture. (In the VA Hospital a spray of desiccant solution absorbs moisture from outside air passing through the conditioner. The desiccant consists basically of lithium chloride, a non-toxic, noncorrosive, bactericidal anti-freeze solution.) During this process two changes occur, one requiring the application of heat, and the other requiring the removal of heat:

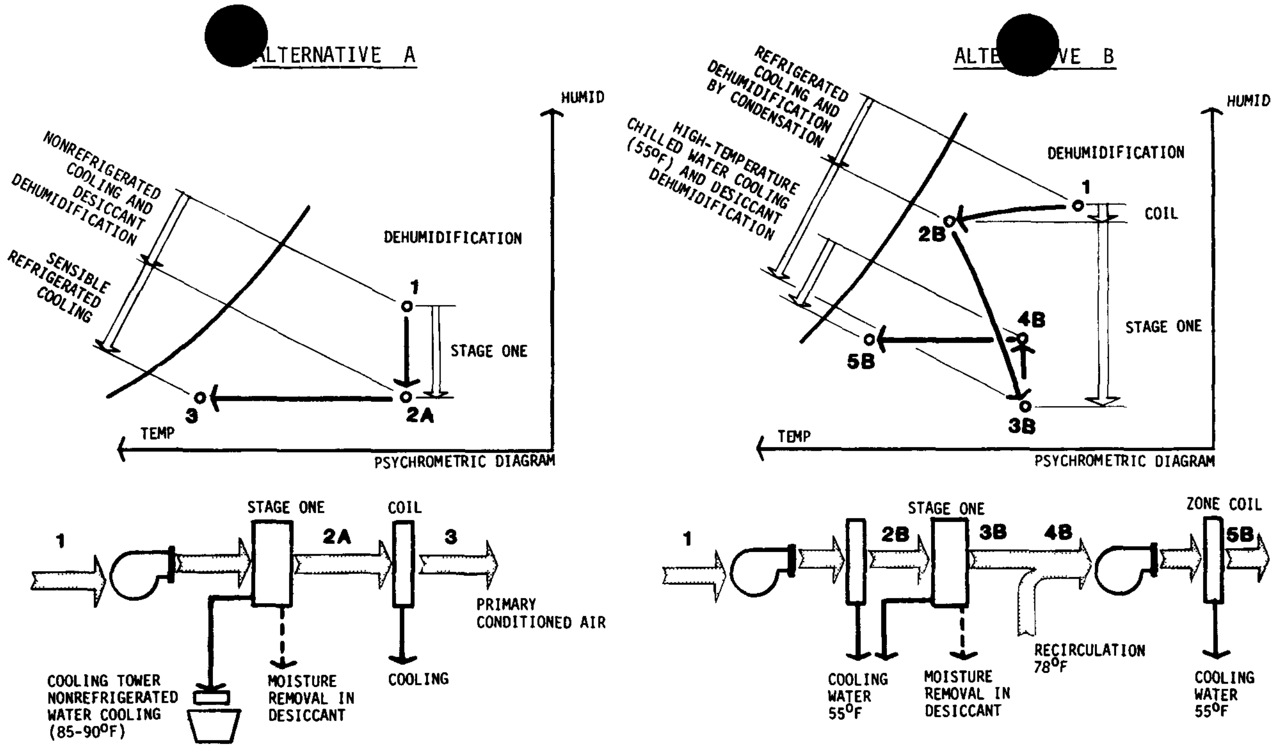
(1) Latent heat is released during moisture absorption. The latent cooling required to remove this heat (and maintain a constant temperature in the conditioner) can be done with nonrefrigerated cooling tower water, with well water, or with high-temperature chilled water (55°F). Figure 2 illustrates alternative desiccant system cooling methods. (At the VA Hospital, which is like Alternative A, nonrefrigerated water precools the desiccant solution before the solution is sprayed into the conditioner to absorb moisture.)

(2) The desiccant loses its effectiveness and requires drying. It is cycled through a regenerator or concentrator where heat is applied and the moisture is removed in the drier exhaust air stream. Low-grade heat of 130-140°F can be used, and can be drawn from thermal storage tanks that integrate solar energy, recoverable waste heat such as engine jacket and exhaust heat, latent heat from the conditioner via a heat pump, etc. (Solar energy and diesel engine heat handle regeneration at the VA Hospital.)

Both the cooling temperature in the dehumidifier (latent cooling) and the higher regeneration temperature can be varied , within certain limits and generally with a fixed temperature spread, depending upon the temperature level of available energy sources and cooling water. The dryness achieved by the process varies as a direct result of two factors, the temperature in the dehumidifier and the concentration of the desiccant solution. Drier air will result if either the temperature in the conditioner is lowered or the desiccant concentration is increased. Therefore, the concentration can also be varied within certain limits in response to available energy sources. However, the temperature required to regenerate the desiccant is a function of the concentration; the more concentrated the solution, the higher the regeneration temperature.

CENTRAL/TERMINAL FUNCTIONS: NEW ENERGY-INTEGRATED OPTIONS

When sensible cooling and dehumidification are separated and dehumidification is by desiccant, there is a broader range of options for the central plant/terminal functional relationship. Sensible cooling can be done centrally--or at terminals. The minimum ventilation quantity of air (0.1 cfm for offices) can be distributed from the central plant (dehumidified only)--or a much larger quantity (dehumidified <u>and</u> cooled). The central chiller can be eliminated entirely if terminal unitary heat pumps are used. (They become highly efficient with desiccant dehumidification, since there is no terminal condensation and they can operate at a higher temperature level for sensible temperature control only.)



NONREFRIGERATED WATER DEHUMIDIFICATION AND COOLING. COIL SENSIBLE COOLING.

HIGH-TEMPERATURE CHILLED WATER PRECOOLING, DEHUMIDIFICATION AND COOLING, AND ZONE COOLING.

Fig. 2. Desiccant Dehumidification Alternatives

These decisions affect capital costs as well as energy operating costs. They determine the size of the central plant, the size and type of the distribution network (large or small ductwork, piping, etc.), and the fan power. In most cases it will be cost-effective to distribute the minimum ventilation quantity of very dry air (thus minimizing distribution costs) and cool at terminals. However, the key point is that factors unique to a given facility have a stronger influence on these decisions--factors such as the size of the latent (humidity) load; the extent to which the latent load is external (outside air) or intern (people-generated); the length and costs of distribution runs; and specific owner requirements. The greater number of design options, with a desiccant system, provides more scope for trade-offs to optimize the capital/operating cost ratio for a specific set of conditions and requirements. Table 1 shows three principal options for the central plant/distribution/terminal relationship.

VA HOSPITAL APPLICATION

Under construction at the Veterans Administration Hospital in Washington, D.C., is the first application of desiccant dehumidification using low-temperature solar energy (130-140°F) to regenerate the desiccant. Solar energy from flat plate collectors alternates with cogenerated heat in a selective-energy system that automatically makes maximum use of available solar energy.

By removing dehumidification from the refrigeration system, supporting dehumidification with solar and waste heat, and then cooling the air efficiently, the VA design is expected to save a significant portion of total costs, including up to 50% of utility energy costs compared with a conventional refrigernation/condensation system. Figure 3 provides a schematic overview of the air conditioning system for the 168,000 ft^2 facility, which includes the following features:

Dehumidification and Desiccant Regeneration

- Dehumidification of outside air (the minimum quantity required for ventilation--19,000 cfm/h) by a moisture-absorbing liquid desiccant in a central conditioner.

- Nonrefrigerated latent cooling, using cooling tower water to maintain a constant temperature in the conditioner by removing the latent heat released by the moisture-absorption process.

- Weak desiccant (moisture-laden) cycles to regenerator for drying and return to conditioner. (In transit, the weak desiccant is preheated by the hot regenerated desiccant that is returning to the conditioner.)

TABLE 1

CENTRAL PLANT/TERMINAL ALLOCATION OF FUNCTIONS
- OPTIONS WITH DESICCANT DEHUMIDIFICATION -

CENTRAL PLANT	DISTRIBUTION	TERMINALS	DESCRIPTION/COMMENTS
I	I	I	I
(a) Desiccant dehumid. of O.A.-drier air (34 gr/#) (b) No central air chilling. Smaller refrigeration plant (no latent load)--produces 55°F chilled water.	(a) Minimum ductwork--drier, ventilation air only (0.1 cfm/ft^2/h). (b) Piping--high-temperature chilled water (55°F).	(a) Dry ventilation air distributed directly to rooms. (b) Fan-coil units recirculate room air, cool sensibly.	Central desiccant dehumid., terminal cooling. Minimum air distribution, dried deep enough to handle humidity load. Minimum ductwork. Minimum size refrig. plant (no latent load). Higher refrigeration COP (due to high-temperature sensible cooling).
II	II	II	II
(a) Desiccant dehumid. of O.A.-drier air. (b) No central refrigeration plant.	(a) Minimum ductwork--for drier, ventilation air.	Terminal unitary heat pumps (small heating/cooling plants). All on 60-90°F closed water loop connected to hot water storage tank--and cooling tower). No terminal condensation.	Central dehum., terminal plants for temperature control. COP of unitary heat pumps increased due to higher temp. (no need to chill for condensation).
III	III	III	III
(a) Desiccant dehumid. of O.A.-drier air. (b) Central sensible chilling (42°F) if all-air system desired. Smaller refrig. plant (no latent load). VAV air handlers mix dehumidified O.A. and variable volume of R.A.	Can minimize ductwork size and costs (and fan power) by distributing smaller quantity of colder (49°F) primary air (dehum. O.A. plus R.A.).	Double-induction boxes (VAV fan terminals) mix variable volumes of primary air and locally recirculated air for temperature control. Supply CV to room.	Central desiccant dehum. and cooling, if all-air system required. If distribution runs are long, reduce duct costs and fan power by distributing smaller quantity of colder air (49°F). Smaller refrigeration plant (no latent/dehumid. load). Double-induction fan terminal boxes minimize energy use by VAV control while maintaining comfort with a constant volume delivery.

COP - Coefficient of performance. Higher COP = less purchased energy to perform a given amount of work.
CV - Constant volume.
O.A. - Outside air.
R.A. - Return air (from rooms to central plant).
VAV - Variable air volume.

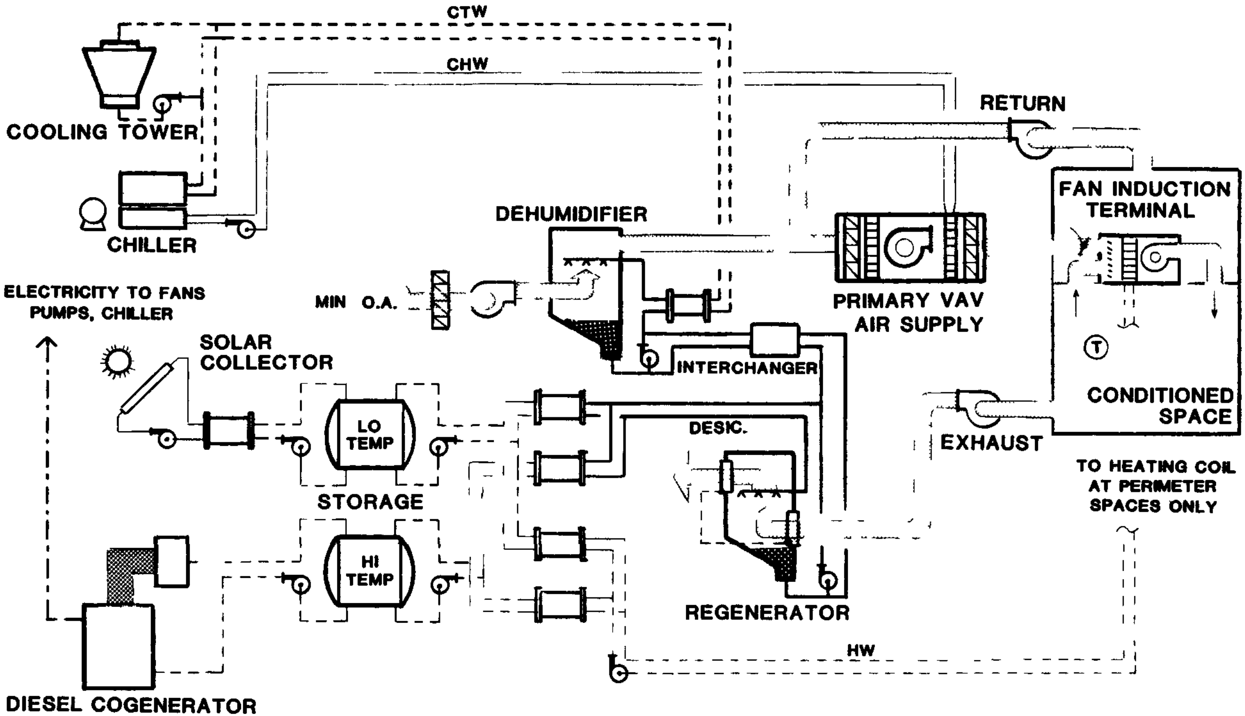


Fig. 3. Solar/Cogeneration Desiccant Dehumidification System (Veterans Administration Hospital)

- Heat for desiccant regeneration (drying) is from (a) low-grade solar energy, which is available about 80% of the time in Washington, and (b) jacket and exhaust heat from a diesel engine/generator set.

- When cogenerated heat is needed to supplement solar, electricity is generated simultaneously and used to power the chiller and the desiccant system's fans and pumps.

- As the weak desiccant is sprayed into the regenerator, moisture is removed in the warmer, drier exhaust air stream blowing through to the outside. A heat recovery mechanism on the regenerator significantly increases its COP and reduces the solar collector area required for a given amount of regeneration.

- A microprocessor control system sequences the use of heat from the low-temperature thermal storage tank (solar-charged) and the high-temperature tank (from engine waste heat) to ensure that
  (a) the solar potential is fully utilized, and
  (b) the diesel engine operates enough to meet the remainder of the regenerator heat requirement--<u>without</u> operating at night (a hospital requirement).

<u>Distribution and Sensible Cooling</u>

An all-air distribution system with central plant chilling only was a design requirement. Given that requirement--and long distribution runs--the most economical solution was to reduce ductwork and fan power by distributing the smallest quantity of air possible. This was achieved by distributing colder air than is usual--49°FDB saturated. First, dry air from the conditioner is mixed with a variable volume of return air in the central air handlers, which cool the air sensibly. From 0.5 to 1.0 cfm/ft^2/h of this primary air is distributed to fan induction terminal boxes which mix it with recirculated room air and supply a constant volume of air to rooms (1.1 cfm) to maintain uniform, comfortable delivery. Perimeter terminals include heating coils.

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NEW DESIGNS AND INSTALLATIONS OF PHOTOVOLTAIC ARRAY FIELDS WITH LOW BALANCE-OF-SYSTEM COSTS†

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ABSTRACT

This paper describes the design, development, and prototype installation of low-cost, modular array fields for flat-plate photovoltaic (PV) systems. Key features of the array field balance-of-system (BOS) components including structures, foundations, intermodule connection, field wiring, and system grounding are identified. Cost projections for the two alternative building-block array-field designs which have been developed show a significant reduction in the BOS costs compared to that experienced in previous PV installations. Prototype array fields of each design have been installed in the Sandia Test Facility. Installation costs of these fields are emphasized in this paper.

INTRODUCTION

For the past two years, Sandia National Laboratories, as manager of the U.S. Department of Energy PV Systems Definition Project, has been involved in a comprehensive program to develop modularized array fields which offer the lowest possible array-field BOS life-cycle costs. The program has now been completed for flat-plate systems with the installation of two prototype array fields in the Sandia Test Facility located in Albuquerque, NM. Each field has a

†This work was supported by the U.S. Department of Energy, Division of Photovoltaic Energy Systems Technology

peak power rating of approximately 30 kW and incorporates the modularized, building-block design which was developed for each during the course of this program.

The development of these fields is heavily based on the installation and cost experience gained from intermediate-sized, full-scale system experiments which have been installed and operated during the past few years through the U.S. PV program. The lessons learned from these experiments have served to identify areas where significant cost reductions can be made.

This paper will describe the development aspects of each of the two array-field designs, identify key array subsystem features, and discuss the prototype installations with primary emphasis on costs.

EXPERIENCE WITH PV SYSTEM EXPERIMENTS

Over the past few years several intermediate-sized PV systems have been installed as a part of the U.S. PV experimental program (1). Three recent ground-mounted experiments have contributed significantly to the understanding of the costs of installing systems. These three experiments are located in Beverly, MA; Lovington, NM; and El Paso, TX. Table I gives the installation costs (1980$) for these three experiments in general cost categories of site preparation, array foundations and structures, and electrical wiring (2). Table I also gives some facts about the systems.

The site prepraration costs range from $\$36/m^2$ of array area for the El Paso site to $\$166/m^2$ for the Beverly site. Both the El Paso and Lovington sites are what might be called favorable for PV system installation in that they are essentially level with no rock outcroppings or underbrush.

Table I. Cost Experience for Three Flat Plate PV System Experiments

SYSTEM FEATURES			ARRAY SUBSYSTEM COSTS ($\$/m^2$)			
System Location	Application	Size (kW_{peak})	Site Preparation	Foundation & Structures	Electrical	Total
Beverly, MA	High School	97	166	156	216	538
El Paso, TX	Computer UPS	17.5	36	108	399	543
Lovington, NM	Shopping Center	104	137	114	173	424

The difference between preparation costs for these sites is in the amount of site leveling done. The El Paso site was used essentially as is and the Lovington site underwent extensive grading for aesthetic reasons only. The Beverly site was on a steep hill and extensive excavation was necessary for system installation. From these costs one can conclude that "favorable" sites are desirable and that as little excavation as possible should be done.

Foundation and structure costs ranged in value from $108/m^2$ for El Paso to $156/m^2$ for Beverly. The bulk of these costs were in the shallow footing foundations. In the case of Beverly and Lovington an extensive amount of concrete was used in the shallow foundations to prevent sliding and tipping of the arrays. This had a large impact on the cost. This experience has led to new designs which utilize deep footing foundations as described below.

The final array subsystem cost element, electrical, contributed $173 to $399/m^2$ to the total system costs. The major items contributing to these costs were the conventional use of steel conduit and numerous junction boxes. Intermodule wiring was also expensive. This has led to approaches which are less conventional in an effort to eliminate as much of these cost items as possible.

The sum of these three cost elements have contributed from $424 to $543/m^2$ to the system cost. For a nominal 10 percent conversion efficiency this translates to $4.24 to $5.43 per peak watt, values which are clearly excessive. One of the principle values of these experiments has been the opportunity to study cost drivers in detail so as to make improvements in system designs. The modularized building-block designs described herein are examples of gaining experience from the current system experiments.

MODULAR ARRAY FIELD INSTALLATIONS

Two contractors, Battelle-Columbus Laboratories and Hughes Aircraft Company, were independently tasked to develop modularized, building-block array fields optimized for lowest life-cycle energy cost. Each design incorporates cost saving features identified through detailed examination of the system application experiments. A summary of the key features for each array-field building block is presented in Table II. Both designs use commercially available PV module hardware of the same size (2 x 4 ft) and output voltage, although each can be readily adapted to other module sizes with minor modifications. Since details of the design requirements and development aspects of each building-block design are discussed elsewhere, only a brief description of each array field, with emphasis on the prototype installation, will be included here (3,4). It should be noted, however, that complete engineering drawing packages and construction specification documents for each design are

Table II. Characteristics of the Modular Array-Field Building Block Designs

	Battelle Design	Hughes Design
PV Module	- 5-Vdc output	- 5-Vdc output
Foundation	- Steel hat-section stakes - Treated wood beam - Support spacing at 4 ft	- Steel footing in front; concrete curb in back - Support spacing at 4 ft
Structure	- Lightweight steel - Two-module panel	- Lightweight steel angle - Four-module panel
Intermodule Wiring	- Crimp-spliced pigtails with insulating pad	- Folded daisy chain with quick-disconnect connector
Field Wiring	- Direct-burial cabling - Buried shield conductor	- Direct-burial cabling - Power collection center
Building Block Size	- 10-kW peak output at NOC - 400 Vdc - Two rows of structures - 165 ft east-west by 18 ft north-south with aisles	- 10-kW peak output at NOC - $\mp$200 Vdc bipolar - One row of structures - 177 ft east-west by 20 ft north-south with aisles

available for immediate use and include example layouts for 20-, 100-, and 500-kW fields using the modular building blocks (5,6).

Battelle Design

The Battelle modular array field, shown in Figure 1, consists of three building blocks, each with a nominal

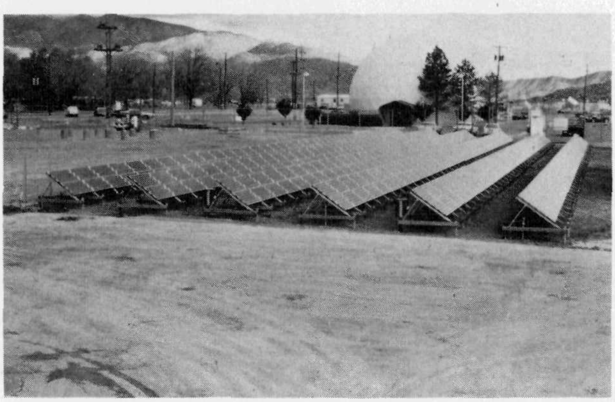

Figure 1. Battelle Prototype Array Field

output power rating of approximately 10 kW. The building block corresponds to a 400-Vdc branch circuit equipped with one junction box. Two 5-Vdc modules, containing six parallel strings of cells and a bypass diode each, are wired in parallel and 82 pairs are wired in series to form the building block. The high degree of paralleling and use of diodes minimizes the effect of cell failures and allows for 20-year operation with a maximum estimated power degradation of 15 percent, assuming normal cell failure rates and no module replacement. All field wiring is direct-burial cabling. The continuous metal support structure is attached to a buried bare-copper-wire counterpoise network to provide a uniform site ground.

The low-cost structure and foundation design is shown in Figure 2. The support system incorporates galvanized steel structural support members and galvanized steel foundation stakes (highway-sign posts) driven approximately 3.5 ft into the ground. Treated wood beams (20 yr or greater lifetime) permit simple fastening of the structural members using lag screws and provide cost-reducing flexibility in alignment during installation.

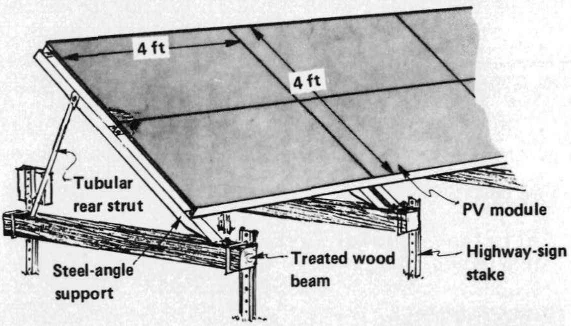

Figure 2. Structure and Foundation Design for the Battelle Building Block

Hughes Design

The Hughes modular array field, shown in Figure 3, also consists of three building blocks, each with a nominal output power rating of approximately 10 kW. The building block is a ∓200-Vdc bipolar branch circuit which consists of two 200-Vdc monopolar subarrays positioned in an east-west row. Each subarray has two parallel circuits of 40 series-connected 5-Vdc modules, each containing a bypass diode and six parallel cell strings. This design also exhibits high reliability and tolerance for cell failures. A daisy chain module-to-module wiring scheme is used whereby the circuits run in horizontal rows, fold back on themselves, and terminate in a common junction box at one end of the

Figure 3. Hughes Prototype Array Field

subarray structure. The modules are connected using quick-disconnect plug-in connectors. Power from each building block is routed from a subarray junction box to a power collection center (PCC) via direct-burial cabling. The PCC contains a standard circuit breaker switch and bus panel, fault detection sensing, and a power control module (PCM) for every two building blocks. Likewise, the PCM contains transient protection devices (MOVs), blocking diodes, and snubbers. Thus, the control of the array field is sectionalized in 20-kW increments.

The structure and foundation design is illustrated in Figure 4. It uses a galvanized steel-channel support

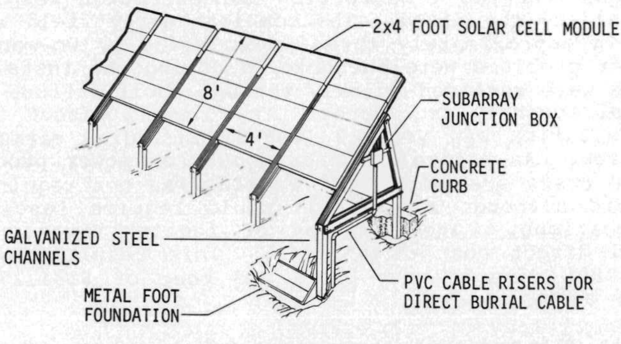

Figure 4. Structure and Foundation Design for the Hughes Building Block

structure and a hybrid foundation. The front foundation is a buried metal foot that is an integral part of the grounding network; the rear foundation is a concrete curb.

ARRAY FIELD COST AND INSTALLATION EXPERIENCE

The Battelle modular array field was installed using PV modules procured from Solec International, Inc. These modules are nominally 2 x 4 ft in size and carry a designation of Model S-4611. The Gardner-Zemke Company of Albuquerque was the construction subcontractor on the project, and was primarily responsible for all aspects of the installation including materials (except modules) and labor. The complete array field was installed in approximately two weeks using a four-man crew. No major problems were encountered and the installation proceeded as initially planned. The overall direct cost of the array field installation was $46,015 (1982$) which includes all labor and materials associated with the survey and layout, site preparation, structural subsystem, and electrical subsystem. These costs exclude the modules and power processing equipment, but do include the cost of module installation as well as all shipping costs for the structural and electrical components. Since the design calls for chain-link fencing around the field and none was included in this installation (the prototype was installed in an area with an existing fence), a mechanical contractor quote for fencing this field of $5,569 must be added to the previous cost for a total installed direct cost, including fee, of $51,584. Deflating to 1980$ shows a direct array-field BOS cost of $\$121.88/m^2$ of collector area (note that a deflator of 0.864 based on GNP-durable goods was used).

The Hughes modular array field was installed using 2 x 4 ft semicrystalline-cell PV modules procured from Solarex Corporation. Abbott Mechanical Contractors, Inc. of Albuquerque was the construction subcontractor responsible for installing the field. The complete array field was installed in approximately three weeks using a two-man crew. Only minor problems were encountered during the installation and these were resolved quickly through modifications to the structural assembly procedures. The overall direct cost of the installation was $49,129 (1982$) including markups for G&A and fee. As before, neither module or power processing equipment costs are included. Fencing was not required for this field although the design would require fencing for other locations. The addition of fencing gives a total installed direct cost of $55,441. This results in a deflated 1980$ direct array-field BOS cost of $\$134.27/m^2$ of collector area.

Table III presents the cost projections developed for the Hughes and Battelle designs, based on a field size of 100 kW and a business volume of at least 1 MW/yr. These values are in dollars (1980$) per square meter of collector

Table III. Array-Field Cost Projections for the Modular Designs

	$1980\$/m^2$	
	Battelle Design	Hughes Design
Site Preparation	8.05	8.96
Foundations and Structures	26.61	32.74
Electrical Subsystem	16.01	16.42
Total	50.67	58.12

area and are prices (including overhead and profit) derived through actual quotations from contractors and suppliers. As may be noted, the installed array-field BOS costs for the prototype fields are slightly more than twice the projected costs for high-volume business. Considering the much smaller field size, the first-time inexperience/costs of installation, and the lack of any continuing level of business to permit volume purchase of parts, the prototype array-field costs compare very favorably with the projections.

CONCLUSIONS

Modular array fields have been developed which offer significant cost reduction, both projected and actual, in the array-field BOS costs experienced in previous PV installations. Prototype array fields of these modular designs have been installed according to the planned installation procedures and no significant problems were encountered. Based on these designs and projected costs, the array-field BOS would contribute approximately $0.50 per peak watt to a PV system with a nominal conversion efficiency of 10 percent. This value is within the allowable system cost allocation which is required to make PV systems cost competitive with conventional energy sources.

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PROGRESS IN RESIDENTIAL PHOTOVOLTAIC APPLICATIONS

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INTRODUCTION

The concept of roof-mounted, utility-tied residential photovoltaic (PV) energy systems has been under intense investigation for the past several years. Initial results clearly indicate that these systems are technically viable. Such systems, using currently available (10 percent efficient) PV products, can meet the bulk of electrical energy needs of energy-conscious families who occupy energy-conservative homes, and widespread implementation could significantly influence traditional electrical energy generation patterns in the nation. The rate of implementation will hinge on many unresolved issues, the most important of which is economics.

THE CONCEPT

As conceived, the utility-tied residential PV system is elegantly simple and consists of but two major components, see figure 1: a roof-mounted photovoltaic array that, at solar noon, generates several kilowatts of power at about 200-volts dc, and an inverter, whose two-wire 60-cycle ac output is tied to the house's existing 240-volt distribution system. The properly sized inverter accepts all the dc power the PV array produces and converts all (less conversion losses) to ac power. If production exceeds consumption, excess power flows to the utility. When production is less than household consumption, as at night, the utility provides the shortfall. In effect, the small residential energy producer uses the

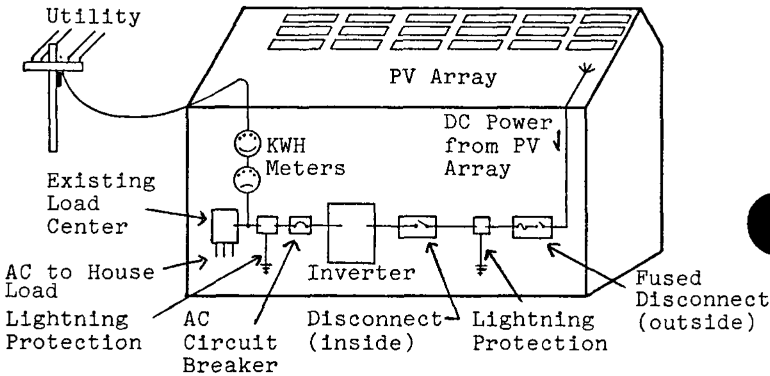

Figure 1. Line Schematic of Residential PV System Showing all Components

utility as a storage system--depositing sun-produced energy during the daytime when production exceeds demand and drawing upon the utility capacity when demand exceeds production. The scenario is extremely attractive to the homeowner and can be equally attractive to the utility whose peak demand is coincident with peak PV production times--the distributed PV production displaces some of the normal and costly peak energy requirement.

As implemented in about 35 sites in the United States and in several foreign installations, several lesser components associated with safety, convenience, protection, and code compliance are usually employed, also shown in figure 1. A fused disconnect, or switch, is usually mounted outside the residence in the dc leg between the PV array and the inverter to allow fireman and utility personnel to disrupt power production. A similar disconnect inside the house may be used, and an ac circuit breaker in the inverter output is mandatory (a new section of the National Electrical Code, scheduled for adoption in 1984, addresses this and other facets of building-mounted PV systems). Lightning protection devices usually protect both input and output sides of the inverter. A second energy recording meter may or may not be required, depending upon state-by-state implementation of PURPA (the Public Utility Regulatory Policies Act of 1978, which requires utility participation with distributed small power producers) and/or individual utility and producer negotiated agreements.

A final frequently employed feature not shown in figure 1 is a dc junction box. Most designers bring electrically individual subsections of the PV array down from the roof to a wall-mounted (outside or inside) junction box. This has the advantage of allowing easy diagnostics in case of problems, and the j-box is a convenient mounting location for fuses, string blocking diodes, lightning protection devices, and one of the previously shown dc disconnects. The j-box does constitute an additional expense, however, and may not be employed once more reliability data are gained.

RENT ACTIVITY AND STATUS

Since 1978 the U.S. Department of Energy has been actively pursuing the utility-intertied residential PV concept as part of the National Photovoltaic Program, a highly structured effort whose goal is to achieve significant penetration of photovoltaics into the nation's energy mix. An important feature of the residential program has been the establishment and operation of several regional Residential Experiment Stations (RESs). These field and evaluate successive generations of residential systems, first behind the fence and then in the community. The objective is to prove the concept, to identify the good and the bad, and to identify and address both technical and institutional issues that would affect widespread adoption. Three such stations exist. The Northeast Residential Experiment Station, operational in early 1980 at Concord, Massachusetts, was established and initially operated by the Massachusetts Institute of Technology (MIT) Lincoln Laboratory and is now operated by the MIT Energy Laboratory. The Northeast RES has five prototype residential-sized PV systems on its site and is collecting data from two off-site, occupied PV residences. The Southwest RES, established and operated by the New Mexico Solar Energy Institute, is on the campus of New Mexico State University in Las Cruces, New Mexico, and was occupied in September 1980, figure 2. It contains eight

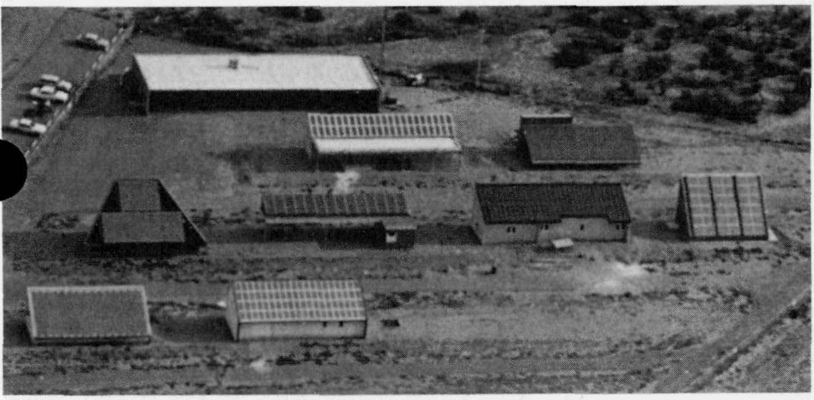

Figure 2. Aerial View of Southwest RES

prototypes on site with a ninth underway and is collecting data from two off-site, occupied PV residences in Santa Fe, New Mexico, and Yuma, Arizona. Details of the Southwest RES systems and first 18 months of operation are in reference 1. The Southeast RES, just underway, will be operated at several sites by the Florida Solar Energy Center and the Georgia Institute of Technology.

Each of the Northeast and Southwest RES prototypes is based on the design of a full-sized, energy-conservative residence appropriate to the region. However, to conserve funds in the initial behind-the-fence phase, each prototype is only a shell structure adequate to ensure that the full-sized PV subsystem is itself replicated and operates under the same mechanical and thermal environment as it would on the full residence. Figure 3 shows the General Electric residence and prototype for the Southwest RES, in which the underarray roof structure (cathedral ceiling) was replicated. Figure 4 shows the TEA, Inc., design; because of the rack mounting, no attempt to replicate the thermal environment was considered necessary.

Activity is not confined to the federal sector, however. Significant private sector effort is underway by utilities and individuals. Among probable others, these utility companies have built or retrofitted PV residences: Georgia Power in Atlanta, Arizona Public Service Company in Yuma, Arizona, and San Diego Gas and Electric in a San Diego suburb. Privately financed homes have been erected in Milton, Massachusetts, and Santa Fe, New Mexico (the latter was a "speculative" venture that sold immediately upon being placed on the market), and several others are underway. While there is no "boom"--current costs preclude the possibility of a strictly cost-effective application where utility service is available--it is clear that the early innovators are active for various motivations and

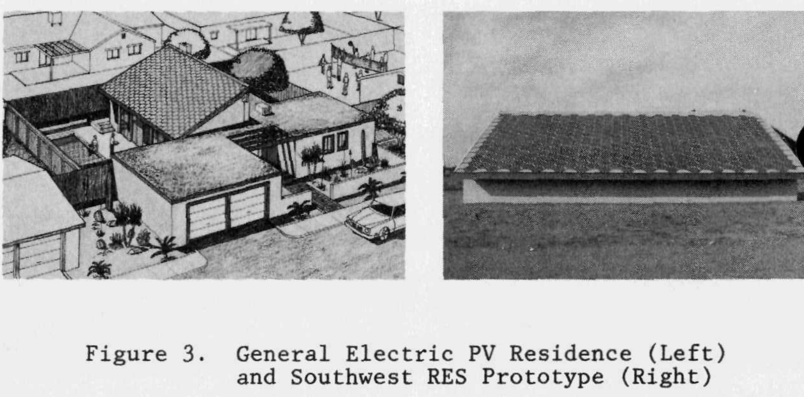

Figure 3. General Electric PV Residence (Left) and Southwest RES Prototype (Right)

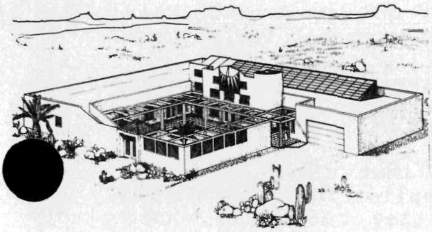 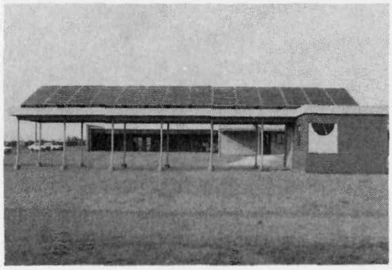

Figure 4. TEA, Inc., Southwest PV Residence (Left) and Southwest RES Prototype (Right)

that many of the utilities are more than slightly curious about a technology that promises to substantially change their way of operation.

RESULTS AND UNCERTAINTIES

The two operational RESs and the several private sector implementations have convincingly demonstrated that there are no significant technical barriers to the concept of residential PV systems. While there have been technical problems, particularly among first-generation inverters, and several technical issues require further experiment and analysis, results show that such small, distributed, utility-tied systems can be safe, reliable, predictable, asthetically pleasing, and essentially "maintenance free." The one exception to the last attribute may well be region dependent and result in a new services sector: roof washing, to maintain the PV array at peak efficiency! Some of our results are addressed in following sections.

PV Arrays. Most designers agree that the bulk of residential PV arrays will be roof mounted. The residence roof represents a readily available mounting structure, usually pitched. A south-facing array pitched at an angle somewhat less than the site's latitude extracts maximum annual energy. It is less accessible to children and animals and less prone to shadowing by flora, fauna, and other structures than ground-mounted arrays. The two existing RESs have evaluated all four conceivable types of roof mounting schemes:

°Direct, in which the PV modules are directly mounted to the roof plate and form the roof weather-shedding surface

°Standoff, in which the modules are "stood off" the roof surface/weather seal a few inches

°Integral, in which the PV modules are the roof plate, with no underlying structure except for rafters

°Rack mounts, appropriate for flat roofs structures, in which additional structure is provided to tilt the array at an optimal angle

Preliminary results indicate that direct mounts are not likely to achieve wide application, particularly in southern latitudes, because they result in unacceptably high PV cell operating temperatures--deleterious to both performance (PV efficiency increases with decreasing cell temperature) and longevity (most manufacturers offer a five-year warranty, and the community believes that a 20-year life is readily achievable). The integral-mounting concept is clearly viable and has an added advantage in that conventional roofing and structure are displaced. Standoff mounts are particularly appropriate for retrofit but will also enjoy wide use in new construction.

Of the approximately 1,200 PV modules installed at the Southwest RES, the overall reliability picture is very good. Of six different models of modules, three have had no failures. Of the remaining three models, one experimental type has had two failures associated with failure of the encapsulating laminate to keep moisture out, and another experimental model (direct mount) has intermittent internal shorting problems. The third problem model, a variant of a commercially available product, has had 7 intermittently open-circuited modules (of 80), believed to be associated with cell interconnects breaking after repeated diurnal thermal cycling. The manufacturer claims no failures in thousands fielded in less severe climates and is presumably improving interconnect design.

Inverters. Early in the RES program, only two brands of utility-interactive inverters in the 5- to 10-kilowatt size range were available, and both were evaluated at the two initial RESs. One, a fairly simple line-commutated device, has been fairly reliable and efficient (greater than 90 percent, daily energy out/energy in), but it is characterized by relatively poor power factor and current harmonic distortion performance. The other, a sophisticated self-commutated unit, is characterized by fully acceptable power factor and harmonic injection performance, but it suffers from low efficiency (less than 85 percent). Early reliability problems seem to have been cured, however. In January and August of 1982, two second-generation new-entrant inverters were retrofitted; each has totally acceptable performance characteristics, which include the ability to force PV array operation at its maximum power point, thereby extracting all possible energy. Neither has had a single failure. At least four other manufacturers are known to be nearing market readiness with residential-sized, utility-interactive inverters. While costs of all available inverters are unacceptably high, it appears to the author that when the market to justify mass production arrives, the inverter manufacturers will be ready with units that are fully acceptable in terms of price and performance.

An experiment conducted in November 1981 at the Southwest RES has sparked significant utility interest in the vital inverter performance characteristic. Both the utilities and the building codes require that inverters disconnect themselves from the utility distribution network when the utility goes down. This eminently reasonable requirement is motivated principally by safety considerations. Utility linesmen and other emergency personnel should not have to cope with backfeed from dispersed power producers when breaks occur. All currently available inverters and those on the drawing boards do indeed have circuitry that senses line voltage and frequency and which, when either of those parameters goes out of tolerance, can shut down the inverter. However, the author and others have speculated that under certain heavy penetration (of photovoltaic, wind, and other dispersed power producers) scenarios, no one inverter in an aggregate can tell if the utility is or is not present; hence, no one inverter will shut down and therefore none will. Specifically, in an electrically distinct portion of a utility distribution network on a given sunny (and perhaps windy) day, if aggregate demand is equal to aggregate dispersed production, the utility provides no power (and hence no current) to that portion of the network. Thus, if the utility drops out, there is no net change and no way for individual units to sense the loss of the utility. The Southwest RES test, under carefully controlled conditions, proved the point with only two inverters on-line. While the day when this hypothetical problem becomes a realistic problem is far away, many of us speculate that the utilities and others should not count on having dispersed small power producers go off-line as soon as the utility does, for we see a finite probability for finite amounts of time when that just will not happen.

On-Site Usage. To gain more insight into regional residential energy use patterns, and therefore a better understanding of probable energy flow in and out of a PV residence, both existing RESs are monitoring electrical energy use of five local (non-PV) residences. Data from each RES confirm that most of the PV energy produced in the daytime flows to the utility. This will be an important consideration in the states or regions where the selling price of the excess energy is the utility's avoided cost and the cost is low. An example of Southwest RES data is shown in figure 5. There the average daily consumption

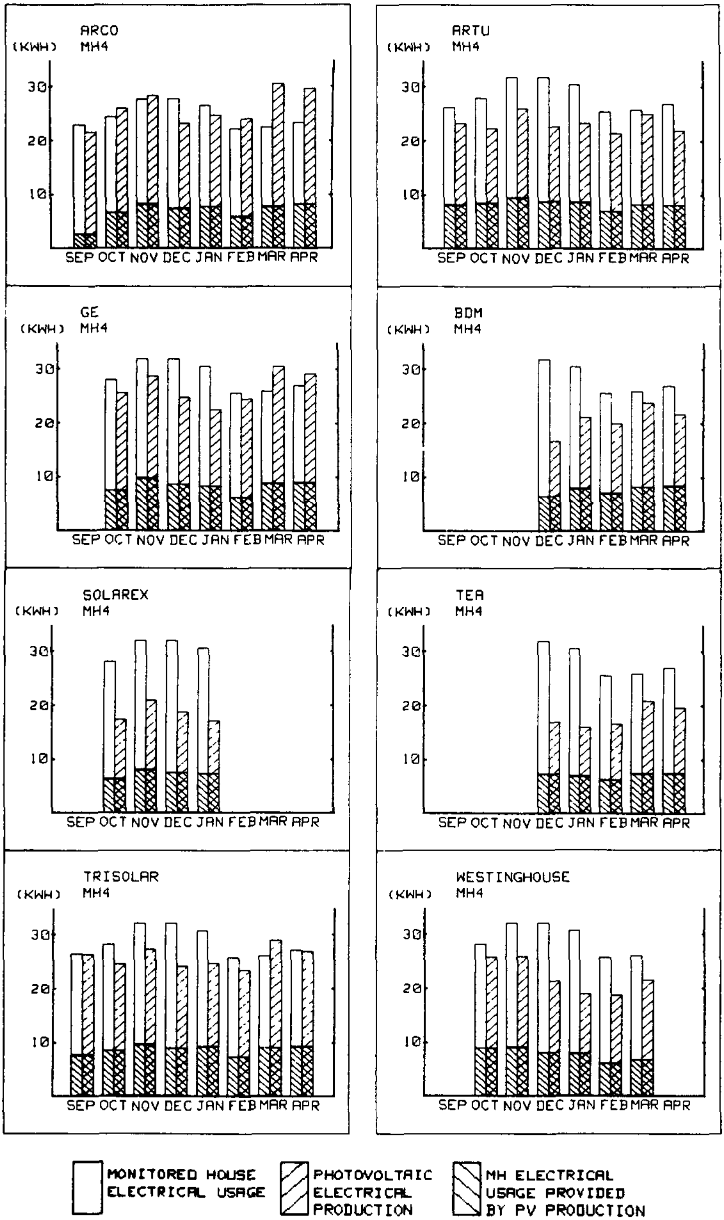

Figure 5. Average Daily Energy Data for the 8 Southwest RES Prototype PV Subsystems if Mounted on MH4

(for September 1981 through April 1982) of our monitored house four (MH4) is shown, along with average daily production of each of the eight Southwest RES prototypes. The cross-hatched areas of the histograms represent that portion of PV production used by the MH4 occupants. Note that percentage used "in-house" does not vary greatly from the smallest PV system (TEA, rated at 4.2 kilowatts peak) to the largest (ARCO, rated at 7.4 kilowatts peak).

Monthly Bills to the Homeowner. In those regions with -sell rates and metering schemes favorable to the spersed power producer, a residential PV system can substantially influence monthly bills. In figure 6 histograms show hypothetical bills (for September 1981 through April 1982) to the owner of Las Cruces MH4 if he were interconnected to the San Diego Gas and Electric Company (SDGE). The bills show two cases: with no PV, and with the ARCO Southwest RES prototype array on his roof. In the cases shown, SDGE's "standard" rates are used, and a net metering scheme is employed (meters are read monthly, and only net difference is billed). Without PV, the bill averaged about $80 per month. With PV, the average bill was about zero.

It must be stressed that while this favorable rate structure does exist in several areas, the situation is far less rosy for the small producer in many areas. As small dispersed producers proliferate and begin to substantially have an impact on utilities, it is inevitable that the situation in the "rosy" areas will change. Clearly SDGE could not operate with zero gross receipts, serving as a daytime receiver of energy and a nighttime supplier, yet being required to maintain peak capacity for a cloudy day (see reference 2).

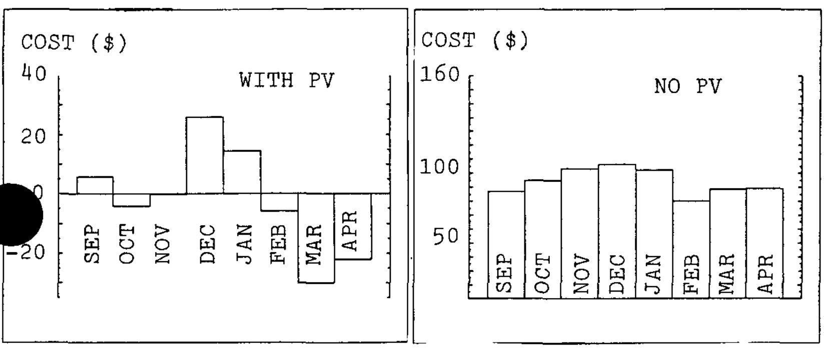

Figure 6. Hypothetical Bills to the Owner of MH4, SDG&E Standard Rates, Net Metering, With and Without the ARCO Southwest RES PV Subsystem

Institutional Issues. The RESs (and, of necessity, the early innovators) are addressing institutional issues, also. Our concerns include:

°Financing. Will the home mortgagers lend the \$8,000-\$10,000 extra for a PV system? Probably not initially; see the next concern.

°Appraisals. There is strong evidence (from solar thermal experience and our own investigations) that appraisers will not value a PV system at cost.

°Codes. Will they change sufficiently rapidly?

°Insurance. There are two major issues here: adequate loss protection for the owner and liability coverage. Many utilities are requiring \$1 million in liability coverage. Until there is experience over many years, either coverage may be expensive.

°Rates. As discussed earlier, the buy-sell rate structure will be a dynamic and nonuniform process for many years.

CONCLUSIONS

Utility-interactive residential PV systems are, in a technological sense, here. A number of federally and privately financed implementations across the nation are yielding vital information regarding performance, cost, reliability, and maintainability. Inverter manufacturers have demonstrated that performance-acceptable units can be fielded, and probably at eventually acceptable prices. If the \$1 per watt PV module were available today, residential systems would proliferate. In the near term, the three RESs and modest activity in the private sector will continue to identify and resolve remaining institutional and minor technical issues that will affect the life-cycle cost of such systems.

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SOLAR CENTRAL RECEIVER TECHNOLOGY DEVELOPMENT AND ECONOMICS – 100 MW UTILITY PLANT CONCEPTUAL ENGINEERING STUDY

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Section 1
INTRODUCTION

This study was conducted to determine the present-day feasibility of designing and constructing a commercial-size (100 MWe) solar thermal power plant, to be located in the southwestern United States. A conceptual design was developed and its financial aspects were explored; the study included consideration of:

- Alternative solar central receiver systems.
- Capital operating and maintenance costs.
- Financing and tax implications.
- Ownership by private utilities, municipal or other public agencies, or private investors.

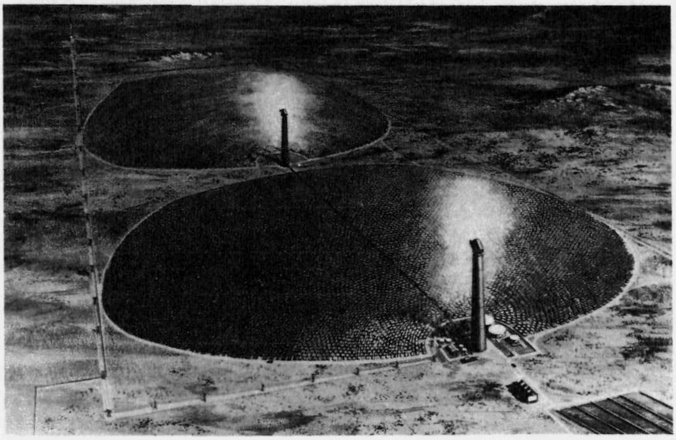


Figure 1. Solar 100

This paper describes the conceptual design, financial analysis, and the conclusions and recommendations. Figure 1 is an artist's rendering of the central receiver plant, designated the Solar 100 Project, which uses two separate heliostat fields and a common power block.

The further development of solar energy at this time is particularly desirable, in order to decrease the country's dependence on imported oil. For this reason, tax incentives are offered by the government for its development; these were examined during the study, and their implications are explained in this report.

Three major corporations, each with its own expertise, pooled their resources as participants in the study. The three companies and their primary responsibilies in the study were:

Southern California Edison Company (Edison)
- Design and Selection Criteria
- Plant Value Analysis
- Siting and Regulatory Investigations
- Steam Cycle Process
- Overall Study and Report Responsibilities

McDonnell Douglas Corporation (MDC)
- Alternative System Evaluations
- Design of Collector Field and Receiver
- Design of Steam Generator
- Plant Control Design
- O&M Cost Estimate

Bechtel Power Corporation (BPC)
- Cost Estimate
- Process Flow Diagrams
- Project Schedule
- Thermal Storage and Transport
- Receiver Support Towers
- Turbine Generator Plant

In addition to the three major participants, other manufacturers and contractors cooperated in the study by providing conceptual designs and budgetary costs.

To the extent possible, previous studies and work were used as a basis for this study and provided the direction of effort, i.e., a solar thermal central receiver station offers the best chance for solar technology to compete in the utility market with energy produced from oil.

The purpose of this conceptual study was to quantify the technical and cost feasibility of constructing a commercial solar thermal power plant. The bus bar energy cost compared to Edison's "avoided cost" is a measure of cost feasibility. The demonstration of technical feasibility was investigated through design analysis and risk assessment of the scheme chosen. It is the desire of the Edison Company to engineer, construct, and start up the Solar 100 plant by 1988 should the project demonstrate viability.

In order to disseminate information on the Solar 100 Project and to solicit comments on the conceptual study, the Utility Advisory Board (UAB) was formed. The UAB consists of various southwest utilities which would have a commercial interest in a cost-effective solar thermal power plant. The binding parameter which is common to all members of the UAB is the availability of solar sites; the southwestern portion of the United States is recognized as one of the best areas in the world for solar development.

Section 2
ALTERNATIVE SYSTEMS

Two alternatives to the molten salt receiver coolant were considered in the study, these are water/steam and liquid sodium Previous study results left some uncertainty in cost and performance This conceptual study examined the two alternatives on a site-specific comparable basis

WATER/STEAM

The system, shown schematically in Figure 2, consists of a tower-mounted water/steam-cooled receiver heated by a field of heliostats The receiver-generated superheated steam is routed directly to a steam turbine where it is used to produce electricity A portion or all of the steam can be routed to the thermal storage system Because of the impracticability of storing a large quantity of high-temperature steam, a secondary fluid is heated and subsequently stored The stored fluid is used to generate steam as needed in a separate steam generator Lower temperature steam produced in this separate steam generator is routed to a lower pressure admission port on the dual-admission turbine It was considered impractical to generate reheat steam with this system, therefore, a lower efficiency nonreheat turbine must be used

The direct production of steam in a solar receiver would appear to be the most natural transition from fossil-fired plants to solar thermal plants However, the transient nature of solar energy makes it impractical to directly couple total solar receiver output to a standard utility turbine Also, storage of large amounts of high-pressure steam to buffer a turbine from receiver output and increase plant capacity factor is at best very costly and at worst virtually impossible Therefore, it is necessary to consider the use of an intermediate fluid for energy storage The transfer of heat from one fluid to another and back again results in losses which yield steam from storage at a lower temperature and pressure than that from the receiver This necessitates the use of an admission turbine (one capable of accepting two different steam inputs rated steam from the receiver and derated steam from thermal storage) and overall reduced electrical generating efficiency for the plant The reduced efficiency translates to a larger, more costly solar collection system

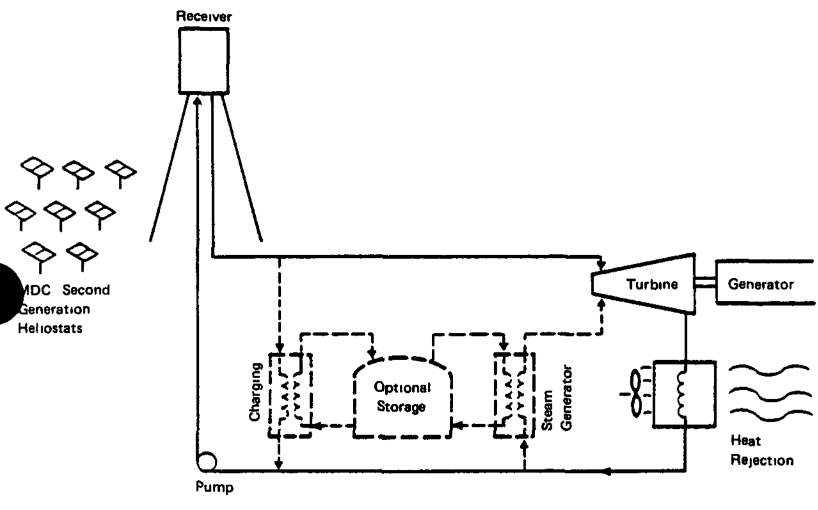


Figure 2. Solar Central Receiver System—Water Steam

LIQUID SODIUM

The system, shown schematically in Figure 3, consists of a tower-mounted sodium-cooled receiver heated by a field of heliostats Sodium heated in the receiver is routed through a sodium/water steam generator The steam is then used in a conventional manner to power a reheat turbine generator set to produce electricity The cooled sodium is returned through the thermal storage to the receiver The thermal storage system buffers the steam generator from solar transients as well as supplies energy during extended periods of no insolation (i e , after sunset)

Use of sodium as a high-temperature heat transfer fluid had its genesis in the nuclear industry Liquid sodium is thermally stable at the elevated temperatures required for pressurized wa reactors and has certain characteristics which make it suitable for a reactor coolant Major sodi equipment, similar in size to that required for solar use, has undergone extensive developme for use in breeder reactor systems This includes pumps, valves, lines, and a steam generator, the sodium receiver development is considered to be as far along as that of the salt receiver

The relatively high thermal conductivity of liquid sodium permits receivers to operate at higher flux levels than with other fluids being considered for solar use The high conductivity limits front-to-back receiver tube temperature differentials and permits higher flux for the same allowable stresses than could be permitted with other fluids The major advantage of operation at high flux is a reduction in receiver size (area) for a specified power level This theoretically reduces the cost of the receiver as well as improves its thermal efficiency (reduces area-dependent losses, convection and radiation) Although these benefits are realized for external cylindrical receivers (externally heated), cavity receivers (internally heated) may be limited by aperture size (i e , the heliostats may require a larger target to minimize spillage losses) and may not realize this benefit

Relatively high cost and low specific heat limit the economical usefulness of liquid sodium as a sensible heat storage media Sodium's lower volumetric specific heat (product of density and specific heat) also drives up the cost of storage tanks Accordingly, sodium-based systems would probably be more competitive only in the lower capacity factor ranges Also, the highly reactive nature of sodium and water is important in the design of sodium components (primarily steam generator systems) and may increase the cost of these components

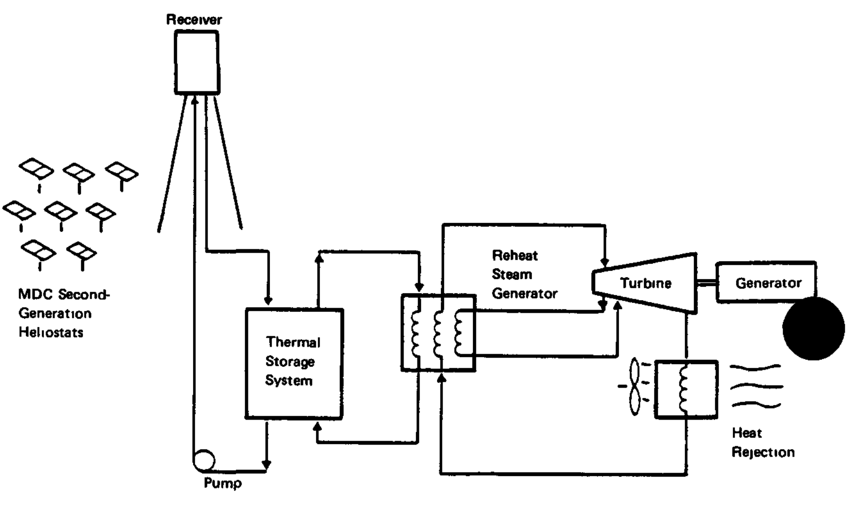


Figure 3 Solar Central Receiver System—Liquid Sodium

SELECTION

The molten salt receiver system showed the best cost performance advantage (particularly at higher capacity factor) *There was no substantial overall relative difference in other more qualitative parameters* Therefore, the molten salt system was selected as the baseline configuration

Section 3
PROJECT DESCRIPTION

The Solar 100 plant, rated at 110 MWe (gross) and 60% capacity factor, will be the world's largest solar thermal power station The design concept of the plant is flexible such that the plant may operate in most southwestern areas, i e , a generic design was chosen to produce the least bus bar energy cost

The Solar 100 plant was conceptually designed to be integrated into Edison's electrical grid system *Presently, the Edison system consists of approximately 15 000 MW of installed capacity and is* comprised of a generation mix, principally oil/gas units This design was also generic in nature to permit installation by different utilities anywhere in the southwest United States and was based on the following requirements

- The plant will be designed to deliver 110 MWe gross (net to a system grid is assumed at 100 MWe) and will be a stand-alone design
- The plant will be capable of providing the maximum load for a period not less than 8 hours when operating solely from insolation on the most favorable solar day of the year
- The plant will have a mechanical availability factor of 96% (exclusive of meteorological limitations) and will have loading and unloading characteristics similar to a fossil power plant
- Minimum thermal storage shall be required to allow operation of the turbine generator during cloud transients Additional thermal storage shall be added consistent with plant economy

The following design criteria also applied

- All systems will be designed in accordance with Edison's Standard Design Criteria insofar as they are applicable to solar design
- The plant will have a 30-year design life
- The plant's seismic design criteria will be in accordance with the building criteria of the Uniform Building Code
- All applicable codes and standards will apply
- The plant will be designed in accordance with the environmental conditions similar to those of Solar One (e g , temperature, insolation, wind, etc), foundation data was, however, site specific
- The unit will be base loaded on a daily startup and shutdown basis

The most important site-specific parameter which was assumed for the project was the insolation data Barstow, being the site of Solar One, had a significant amount of solar radiation and meteorology data already recorded Accordingly, this data with minor modifications was used at the nearby selected site in Lucerne Valley

It was the intent of the study to determine the size and loading of the solar plant to meet two different criteria

- A generic plant design that would be applicable to location anywhere in the southwestern United States and Hawaii
- A plant that would best suit Edison's requirement

The study indicated that a 100 MWe plant operating at a 60% capacity factor would produce the least bus bar energy cost However, Edison's initial investigation into dispatch requirements indicated that a plant of 25-40% capacity factor would be optimum Further analysis indicated only a slight cost penalty associated with reducing the capacity factor from 60% to 40% assuming a constant energy production (i e by reducing the capacity factor from 60% to 40% and raising the peak capacity from 100 to 150 MWe) For the purposes of this study, a generic 100 MWe, 60% capacity factor plant was assumed, a determination was also made of cost sensitivity to variations in capacity factor

The solar thermal power plant is sized to produce a nominal 100 MWe net when operating at rated conditions The selected receiver fluid for this conceptual study is molten nitrate salt, however, further consideration of alternate fluids may be desired before a selection is made for final design A two-module collector field is used, each with a separate tower, however, the power block will be common to both fields The capacity factor was designed at 60%, which therefore requires a solar multiple of 2 4 (i e , ratio of design-point solar power to rated steam generator required power) and heat storage of approximately 8-1/2 hours The steam cycle uses one standard reheat utility turbine of approximately 110 MWe gross rated capacity with six extraction points for feedwater heating

The concept of solar thermal electric power is relatively simple and is illustrated in Figure 4 Solar radiation is collected at the receiver by the use of heliostats, the heliostats track the sun (by computer control) and reflect the radiation back to the receiver The layout of the heliostat positions is called a collector field A collector field may completely surround the tower (similar to the 10 MWe Solar One plant), or the entire heliostat field may be located north of the tower, as is the case for this study The receiver is a partial-cavity type to capture the solar radiation with minimal losses Molten salt used as the receiver fluid will be heated by the solar radiation and cooled by water/steam in the steam generator The receiver fluid circulation is therefore a closed loop, constantly circulating the molten salt to provide heat to the steam cycle Once steam is produced, electric power is generated using a conventional Rankine cycle

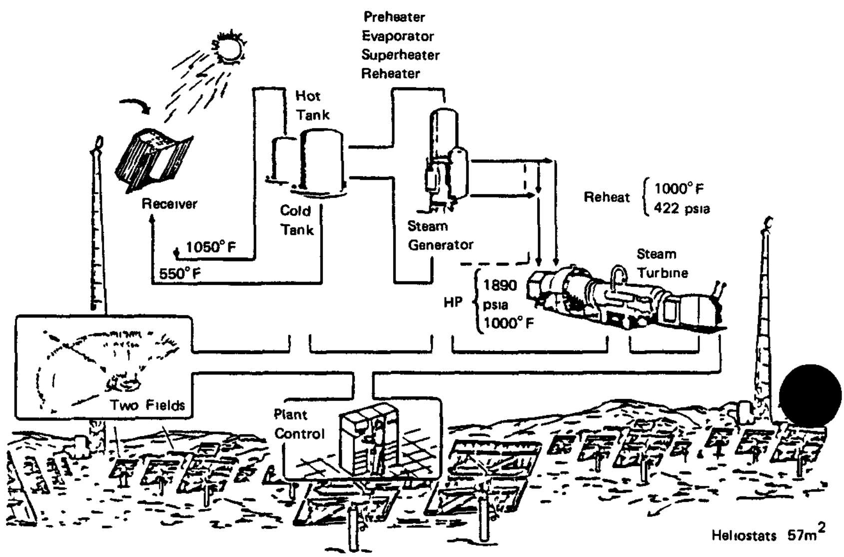


Figure 4 100 MWe Solar Central Receiver Plant

An important aspect of solar thermal electric power is the method for heat storage In order to reduce the cost of electricity produced by the plant, the facilities must be used as much as possible Studies indicate approximately 8-1/2 hours of storage are required to minimize bus bar energy costs Specific analysis of energy and capacity worth would have to be performed by each prospective owner/utility since the generic worth of energy from Solar 100 (or any power plant) should not exceed the energy worth of alternative sources

The study was site-specific with location of the solar plant at the proposed Lucerne Valley peaker park site located approximately 30 miles southeast of Barstow, California

Collector System. The two-module collector system is arranged in a north-south alignment The collector system consists of heliostats, field wiring and electrical equipment, and collector control and alignment equipment The two fields will have a total of approximately 15,400 heliostats (assuming MDAC Model 50 design) and will require about 1 4 square miles of land area (0 7 square mile for each field)

Receiver System. There is a receiver and tower for each collector module The receiver system consists of the tower and the receiver unit (partial-cavity type) with its control, surge tanks, door, and support structure The top of the towers will be approximately 585 feet from the base of the receiver structure The midpoint of the receiver aperture will be approximately 675 feet above grade

Storage and Transport System. The storage and transport system includes all receiver fluid piping to the receiver and steam generator, two storage tanks (hot and warm storage at 3 6 million gallons and 3 3 million gallons, respectively), and the associated pumps, valves, controls, and cover gas systems Total salt flow will be approximately 6,500 gpm per receiver, salt leaving the tower will be 1,050°F and will return at 550°F from the warm storage tank after leaving the steam generator

Steam Generator System. The steam generator system includes the preheater, boiler, superheater, and reheater heat exchangers and their associated piping, valves and controls Main steam superheat will be approximately 1,000°F at 1,800 psia with a flow rate of 742,000 lb/hr Reheat steam will be approximately 1,000°F at 442 psia with a flow rate of 653,000 lb/hr

Steam Cycle. The steam cycle includes the turbine generator, condenser, feedwater heaters, and the associated pumps, valves, and controls The cycle is a conventional Rankine cycle of the type found in most fossil-fired plants and will have six stages of feedwater heating The turbine operates with sliding or variable presssure during daily startup and shutdown for economic and maintenance reasons The turbine will be rated at relatively low nominal pressure of 1,800 psig to reduce expected downtime and maintenance The gross turbine heat rate is 7988 Btu/kWh

Plant Control System. The plant control system includes hardware and software necessary to coordinate the control of the plant including the heliostat field and to provide operator interfaces and displays

Balance of Plant System. The balance of plant system includes the facilities, utilities, switchgear, cooling tower, and other conventional equipment and structures necessary to complete the plant Some of the subsystems may be shared with the peaker plant as planned for the Lucerne Valley (e g , firewater, service air, and water)

Plant operating modes are most easily described by separating the plant into a heat collection (including heliostat and receiver) and a power generation function The heliostats collect the sun's direct insolation and concentrate the energy on the receiver The receiver transmits its energy to the salt from the warm storage tank and the heated salt is returned to the hot storage tank The power generation function uses a conventional Rankine cycle to produce power

HELIOSTAT OPERATING MODES

The heliostat or collector system operating modes can be commanded either automatically or manually through the plant control system, or manually in the field The two operating modes are normal tracking and standby There are additional nonoperating modes (or stow positions) for nighttime, high winds, and periodic maintenance (including cleaning)

Normal Tracking. Each operational heliostat tracks the sun so that its reflected beam strikes the receiver at its preassigned aim point Tracking is by articulation of two axes (azimuth and elevation) to positions based on a computed, apparent sun position

Standby. For emergency or planned reasons the heliostats can be directed to a standby position The beam is directed off the receiver to a nearby safe position

Normal Stow. The preferred heliostat stow position will be with its reflector surface nearly vertical Face-up storage is planned for high winds

Cleaning and Maintenance. Manual positioning of the heliostats, either individually or in groups, to positions that facilitate corrective maintenance and/or cleaning will be possible

RECEIVER OPERATING MODES

The two operating modes for the receiver are normal operation (including startup and shutdown), and warm or overnight hold There is an additional nonoperating mode of cold shutdown

Normal Operation. In this mode, salt is supplied to the receivers at about 550°F with adequate pressure to maintain receiver flow and control The salt flow is regulated by a throttle valve downstream of the receiver feed pumps There are three half-capacity receiver feed pumps for each receiver

Under most conditions of insolation transients, the feed-forward control on the receiver will maintain adequate salt outlet temperature control When large, opaque clouds come over the field, a 20% rated flow minimum condition may be reached which results in receiver outlet temperature of less than 1050°F The minimum flow constraint of 20% is applied under all insolation conditions

Warm or Overnight Hold. During periods of no insolation, such as nighttime, the receiver is put in a warm hold mode The receiver door is closed, and the collector system is stowed Salt circulation is halted, and trace heaters are used on demand to maintain the salt in a molten state (above 430°F)

POWER GENERATION OPERATING MODES

The two operating modes for power generation are normal operation (including sliding-pressure operation and low-power operation) and warm hold There is also an additional nonoperating mode of cold shutdown

Normal Operation. In this mode, salt is supplied to the steam generator at 1050°F The steam generator produces primary steam at 1000°F and 1800 psi and reheat steam at 1000°F The salt is returned to the warm tank at 550°F Feedwater is supplied at 460°F

During startup, the feedwater heaters operate at a reduced temperature, and steam generator drum steam is fed to the salt preheater to peg feedwater temperature at 460°F The pressure ramp rate is controlled to keep the superheater inlet temperature ramp rate below 150°F per hour due to metallurgical (thermal stress) limitations Since the turbine is required to execute daily off-on cycling, sliding pressure is used to start up and shut down the turbine and minimize the thermal cycling effects on the turbine

Warm or Overnight Hold. Under warm shutdown, the superheater and reheater are isolated by shutoff valves on both salt and steam sides The temperature change is slow, and these units will not require the use of trace heating The evaporator and preheater are similarly isolated with trace heating as required

Section 4
PERFORMANCE

The performance analysis of the Solar 100 Plant is categorized into three parts (1) insolation model, (2) plant output, and (3) availability analysis

INSOLATION MODEL

Estimates for the insolation (sun energy) available for central receiver systems are generally developed in one of three ways (1) measurement of direct normal insolation, (2) correlations based on measurements of global or total horizontal insolation and meteorological data, or (3) correlations based on models of the atmosphere and meteorological data The DELSOL (developed by Sandia) and R-CELL (developed by University of Houston) computer programs generate insolation data by the latter method, and these codes were used in Solar 100 modeling The daily insolation profile was then adjusted based on measurements from the first and second types of estimates

For Barstow, 4 years of direct normal insolation measurements are available through Edison and West Associates, and approximately 30 years of data are available using the Jet Propulsion Laboratory SOLINS computer program with SOLMET data Due to the extensive insolation data available from Barstow, it was assumed all Edison sites would, with minor variations, exhibit the same insolation This resulted in a value of 2576 kWh/m^2 year with an average of 3230 hours of usable sunlight per year These values include the effects of weather and are based on using all sunlight for elevations greater than 10 degrees above the horizon (i e , usable insolation)

PLANT OUTPUT

The steam generator and turbine generator are sized for a gross output of 110 MWe The net plant output during operations at full gross power rating (110 MWe) range from a minimum value of 96 6 MWe (collector fields and all receiver feed pumps operating) to a maximum value of 104 5 MWe (early evening storage operations before receiver trace heating is required) The annual average net power output is 98 3 MWe

The annual energy delivered from the receivers to the storage tank is enough to operate the turbine generator at rated gross output for 5325 hours per year, assuming 100% plant availability The plant auxiliary loads are expected to consume 62 million kWh per year leaving a net annual production of approximately 24 million kWh* (assuming 100% plant availability) The annual output is 489 million kWh after accounting for planned and unplanned outages

AVAILABILITY ANALYSIS

The availability calculation for this power plant was performed in two ways The analysis for the solar portion of the plant (heliostat field, receiver, steam generators) was performed by estimating the predicted failure rate and recovery time for each component The remainder of the plant was analyzed by utilizing industry-wide availability data for similar sized steam units Table 1 compiles the summation of the availability analysis

*Transformer losses and efficiency degradation in the turbine and auxiliaries over a 30-year life were not included in the production calculation

Table 1 Availability Analysis

System	Expected operating time* (hr/yr)	System downtime – unplanned outage (hr/yr)	System unavailability (%)
Heliostat field	3313	0	0
Receivers (2)	3313	104	0 59
Steam generator	5256	64	0 72
Turbine	5256	220	2 51
Molten salt loop			
Receiver	3313	20	0 11
Steam generator	5256	10	0 11
Control system	8760	0	0
Unplanned outage – total			4 04
Planned outage			1 45
Plant availability			94 49% (≈ 94 5%)

*Initial estimates of operating time, availability analysis was not revised to reflect final estimates of operating times

Section 5
COST

The capital cost estimate is shown in Table 2 The estimate is based on a joint effort by the three participating companies The estimate includes all additives (i e , labor, fringe benefits and payroll taxes, field indirect costs for manual and nonmanual labor, field engineering and indirect material, and equipment costs) *Contingency, averaging approximately 20%, is also included* Cash flow in 1981 dollars is shown in Table 3

Operations and maintenance (O&M) costs have been estimated for plant operation during the first year and an average subsequent year These are itemized in three categories material, water, and labor The estimates are shown in Table 4

Table 2. Conceptual Cost Estimate Summary by System Solar 100 MW Thermal Plant (Molten Salt)

System Description	Cost (Dec 1981 $, millions)		
Collector field/receiver/tower	206 5*†		
Thermal storage	52 5		
Steam generator/turbine-generator	23 4*		
Plant master control	12 1*		
Balance of plant	35 7		
Subtotal		330 2	
Switchyard/transmission	3 6		
Subtotal		3 6	
Total field cost		333 8	
Spare parts and maintenance equipment	8		
Sales Tax	12 7		
Subtotal		13 5	
Engineering and home office	29 0		
Subtotal		13 5	
Additional contingency		54 5	
Escalation		—	
Total - Work Order Level (1981 $)			430 8
Allowance for funds used during construction (AFUDC)			88 3
Cost of capital (COC)		127 1	
Construction overhead (without AFUDC or COC)			17 5
Total capital cost (with AFUDC)			536 6
Total capital cost (without AFUDC or COC)			448 3
Total capital cost (with COC)			575 4
			(≈ 580 0)

*Part or all of the cost is MDC scope which includes their assessment of contingency
†Cost estimates are based on a price for 75,000 heliostats

Table 3. Cash Flow

Year	%	Capital cost (Dec 1981 $, millions) Work order	With AFUDC	With COC
1982	0 5	2 3	2 7	2 9
1983	2 6	11 7	14 0	15 1
1984	18 4	82 8	99 4	106 7
1985	14 6	209 7	251 6	270 3
1986	28 9	130 0	156 1	167 6
1987	3 0	13 5	16 2	17 4
Total	100 0	$450 0	$540 0	$580 0

Table 4. O&M Summary Average Year ($ thousands)

	Spares, parts, and consumables	Service contracts	Total ($)
Materials			
Collector field	383	370	753
Tower	1	—	1
Receiver	11 1	—	11
Thermal storage and transportation	26	—	26
Steam generator	1	—	1
Turbine and balance of plant	548	—	548
Plant control	—	202	202
			1542
Water cost (expensed)			1393
Labor	Manning		
Supervisor	4		160
Operators	27		1138
Maintenance	26		1035
Security	10		277
			2610
Total			5545

Section 6
FINANCIAL ANALYSIS

The purpose of the financial analyses which follow was to develop a preliminary assessment of the financial feasibility of the Solar 100 project as described and defined in earlier sections of this report

A 100 MW solar facility could reasonably be owned by a utility, a municipality, or – with modification of existing federal regulations – an entrepreneur To ensure that the alternate scenario results would be based on comparable data, the common input values and assumptions, as detailed in Table 5, were held constant between scenarios

The mode of ownership would impact the means of financing and the availability of tax credits Currently, if owned by a third party a solar facility would be eligible for a 10% investment tax credit (ITC) and a 15% energy tax credit (ETC) A utility would qualify for only the ITC while a

Table 5. Financial Analysis Common Assumptions

General

- Plant rated capacity – 100 MWe (100% electricity, no cogeneration)
- 30-year operational life
- Power availability
  - 489,990 MWh/year net of scheduled and forced outage and auxiliary power requirements
  - Scheduled availability

1986	12 5%
1987	62 5%
1988 on	100%

Annual escalation rates

■ Capital equipment	10%
■ O&M and A&G	9%
■ Energy payments	
1982-1985	11 0%
1986	10 0%
1987-1990	9 6%
1991 on	9 3%
Property tax	2 0%

Revenues

- Schedule – avoided cost basis (November 1981 basis)
- Energy payments
  - Rates (November 1981 – January 1982 dollars)

$0 080/kWh.	On-peak
$0 073/kWh	Mid-peak
$0 071/kWh	Off-peak

Costs

- Investment

	Dec 81 dollars
Base investment (incl engr)	$363 6 million
Sales tax	12 7
Additional contingencies	54 5
SCE construction overhead	17 5
Total investment	$448 3 million

Table 5. Financial Analysis Common Assumptions (Continued)

- O&M

Annual O&M (incl waterline)	
Average	$5 55 million*
1st year add (one time)	$0 81 million**
Municipal bond debt service	$0 74 million***
One-time water surcharge	$1 11 million
Insurance	2 5% of principal
A&G	1 1% of investment*
Property tax	1 0% of investment

*Allocate relative to power availability
**1986 cost - $1 25 million
***$0 985 million/year, starting in 1986

Capitalization

- Assumptions

Element	Debt	Capitalized for TC	Capitalized for Deprec	Capitalized for P Tax	Expense	Levelized O&M
Capital	X	X	X	X		
Sales tax	X	X	X	X		
IDC/commit fees		X	X			
Property tax		X	X			
Construct/liab insur	X	X	X	X		
Engineer (1st 2 yr)	X	A	A		X	
SCE AG&I	X	X	X	X		
Water maint						X
O&M - Basic					X	
- AG&I					X	
- Property tax					X	

X = Prime treatment
A = Alternative

- Funding

Type cost	N/R engineering		Capital investment				
Year	82	83	84	85	86	87	Total
Percent	5	2 6	18 4	46 6	28 9	3 0	100 0

municipally owned facility would not qualify for either credit, nor would it pay taxes in general Financing would be more readily available to a utility or municipality than to an entreprenuer The cost of financing would be least for a municipality and most costly to the entrepreneur

Given the unique set of advantages and disadvantages, the overall assessment of the results based on the financial analyses of the three scenarios indicates that a solar 100 plant owned by private investors who sell the output to Edison shows the most promise However it is important to note that under the present provisions of PURPA a 100 MW solar plant owned by private investors would be subject to state and federal rate regulation

UTILITY OWNERSHIP

A utility's objective is to minimize the cost to the ratepayer subject to the constraints of reliability, capital availability, regulatory law, and demand The focus of a financial analysis from the utility perspective must therefore be on the total cost of a project to the ratepayer The objective of the financial analysis of the 100 MW Solar facility was to access the reasonableness of the various potential modes of ownership, the total cost to the ratepayer under utility and third party ownership were compared Additional utility specific assumptions are shown on Table 6

For a facility constructed and owned by a utility, once operational, the ratepayer will be charged the return of capital, return on capital, income taxes, all other taxes, administration costs, and expenses incurred to operate and maintain the facility For the purpose of this analysis, perfect and instantaneous ratemaking was assumed This implies that all costs are recovered as incurred Additionally, full normalization of all tax timing differences was assumed It was also assumed that perfect and instantaneous ratemaking removes the only financial risk associated specifically with the solar project Because the project is relatively small and to the extent that the Commission allows full cost recovery, there would be no incremental financial risk per se

Table 6. Financial Analysis Utility Assumptions

Cost of capital			
Component	Capital ratio	Cost	Weight cost
Long-term debt	45%	12%	5 4%
Preferred stock	11	11	1 2
Common stock	44	19	8 4
Total	100%	—	15 0%
AFUDC rates			
1982			9 20%
1983			9 75
1984			10 25
1985			10 50
1986			11 30
1987			11 60
SCE capital escalation rates			
1983			13 0%
1984			14 0
1985-1986			11 0
1987 on			10 0

Capacity payment

- $180/kW/year
- 60% nominal capacity factor

Tax considerations

- Federal
  - 15-year ACRS depreciation
  - 10% ITC
- State
  - 30-year straight-line depreciation

Regulation

- Normalization of ACRS depreciation & ITC

In the early years the largest components of the revenue requirement for a Solar facility are the return of capital and return on capital Consequently, as shown in Figure 5, the annual revenue requirement declines until the year 2001 At that time the operating costs start to dominate the total revenue requirement, causing it to increase by the end of the operating life The revenue requirement has increased by about 17% over the initial levels Avoided cost payments, under the study assumptions, would increase over the entire 30-year period Figure 6 shows that the annual revenue requirement and the avoided cost payment would equalize in the 1995-1996 time period From 1996 on, the annual avoided cost payment would exceed the annual revenue requirement

For decision-making, the total present worth of the annual revenue requirements and the total present worth of the avoided cost payment must be compared Figure 7 shows that, because of high revenue requirements in the early years, the cumulative present worth of the revenue requirement remains above the cumulative present worth of the avoided cost payment throughout the 30 years Note that that is true whether a 10% capital escalation rate or Edison's corporate capital escalation rates are assumed

	Capital escalation assumptions	
	10%	SCE Corp
	(Millions)	
Total PW revenue requirements	$601 1	$640 5
Total PW avoided cost payment	536 1	536 1

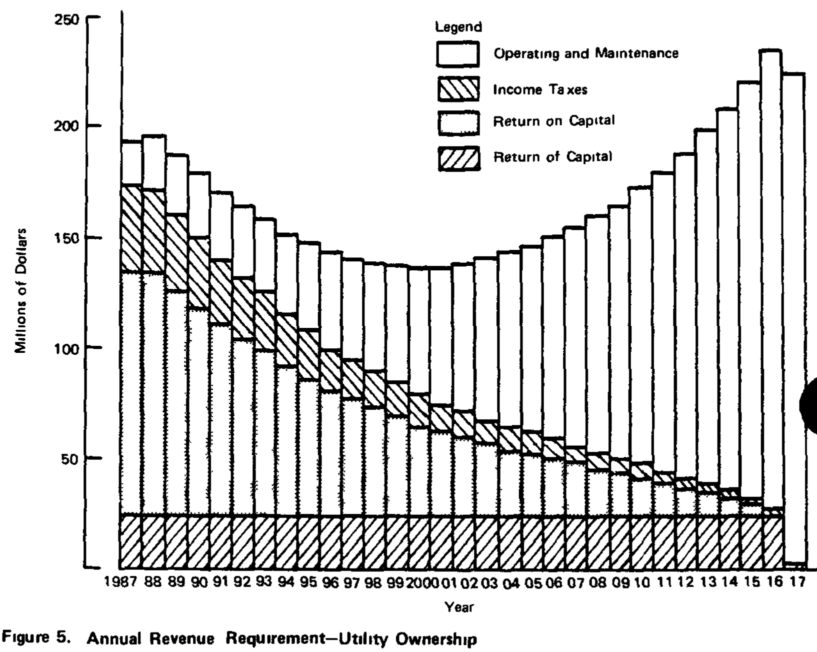


Figure 5. Annual Revenue Requirement—Utility Ownership

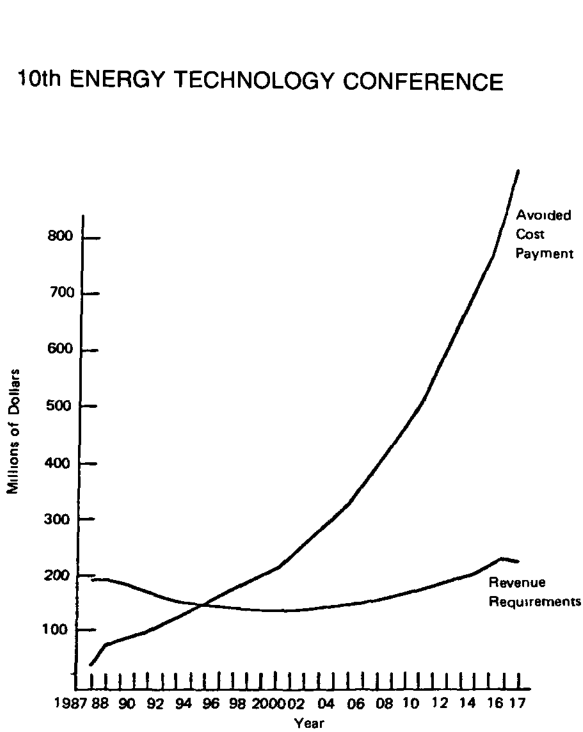


Figure 6. Comparison of Annual Cost to Ratepayer—Utility Ownership

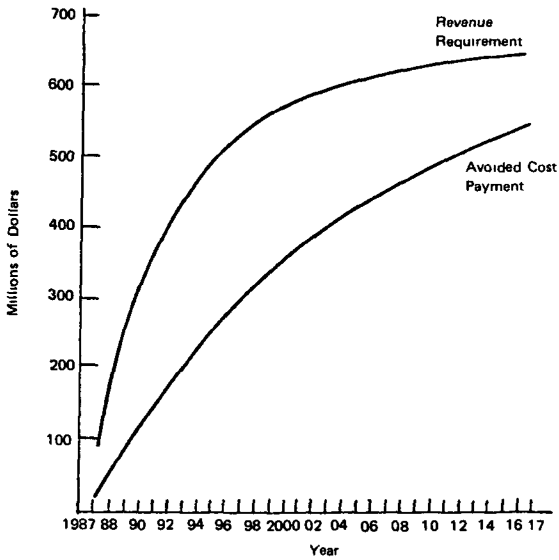


Figure 7. Utility Ownership—Cumulative Present Worth

These results indicate that the cost to Edison's ratepayer of obtaining electricity from a 100 MW solar facility would be minimized by purchasing the power from a third party at full avoided cost

MUNICIPAL OWNERSHIP

This scenario assumes that a city or other local public agency owns its own distribution system and wants to consider developing its own generating capacity to serve at least part of the needs of its customers rather than depending on purchased power

From the standpoint of the Southern California Edison Company, this scenario has the advantage of making approximately 100 MW of generating capacity in the Edison system presently used to serve public agencies in its service area available for alternative uses, thus delaying the need for adding new capacity

In exchange for a substantial present investment the community would be gaining the potential for significant long-term savings

- The facility can be financed with tax-exempt bonds thus reducing interest costs
- Materials and equipment used in construction would not be subject to sales or use taxes
- The facility would be exempt from property taxes

On the other hand, the potential tax benefits associated with private financing and ownership would be lost under this scenario

To assess the possible interest in ownership of a 100 MW solar plant by a local public entity a financial analysis of such an investment was conducted The assumptions used in the base case analysis are found in Tables 5 and 7 the results of the analysis are shown in Figure 8 which is based on an estimated average cost of purchased power of 6 0345 cents per kilowatt hour in the fourth quarter of 1981 and shows how the estimated cost of purchased power compares with the estimated cost of power generated at the solar plant based on the assumptions used No transmission costs have been included in the analysis

Table 7. Financial Analysis Municipal Assumptions

Construction costs	
■ Total investment	$448 3 Million
Less	
Sales tax	12 7
SCE constr overhead	17 5
Municipal investment	418 1 million
Financing	
■ Interest on bonds – 12%	
■ Bond reserve fund – 1 yr level debt service	
■ Bond issuance cost – 3% of bond amount	
■ Interest earned on unexpended bond proceeds – 14%	
■ Interest earned on debt service/reserve fund – 12%	
■ 30-year maturity	
■ Level debt service	
■ Bond issuance 3Q82	

ENTREPRENEUR OWNER

The entrepreneur owner supports the utility's objective of minimizing ratepayer cost since the entrepreneur's income is determined by the utility's avoided cost as allowed by the energy supplied The entrepreneur must determine whether the income received in meeting the utility's objective will earn a satisfactory return on the investment in the resources required to generate

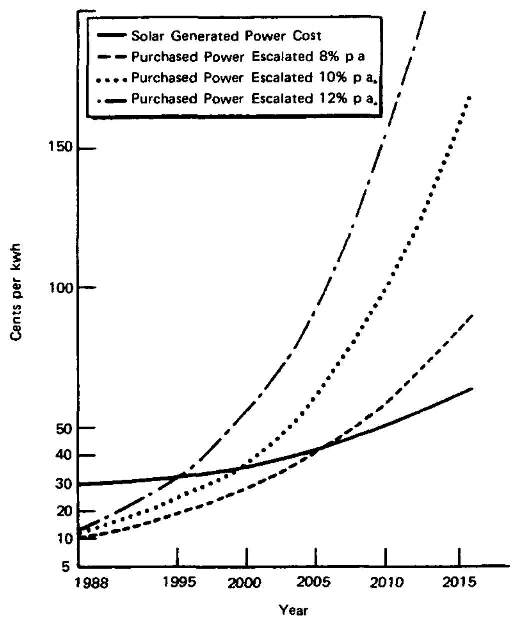


Figure 8. Estimated Cost of Solar Generated Power Compared to Estimated Purchased Power Costs at Selected Escalation Rates

the energy stream A satisfactory return must meet or exceed the marginal rate acceptable to the investor considering the perceived resource requirements and risks inherent in the project

The acceptable marginal rate will vary with each investor, so that the analysis seeks to define the cash inflows and outflows, and then to determine values for the various financial figure of merits that an investor would employ in making an investment decision In addition, financial sensitivity to various risks such as capital cost overruns and unrealized avoided costs are of interest to the investor

The analysis capitalizes all costs during construction except those in the first two years which are engineering-related The latter are expensed and, thus, not included in the tax credit and depreciation base Federal energy tax credits are taken and the 5-year ACRS schedule is employed, but state energy credits are not taken and 8-year depreciation is assumed for state taxes The after-tax results are summarized below

	NPV @20% (dollars in	Maximum exposure* millions)	IRR	Year 2000 Sales	Return on Capital
Baseline	$35	$ 67	35%	35%	16%
80% cost multiplier	$50	$ 54	43%	37%	21%
120% cost multiplier	$20	$112	28%	34%	12%
100% avoided cost	$48	$67	39%	36%	18%
80% avoided cost	$23	$67	30%	34%	13%

*Occurs in 1985

The baseline case calculates the avoided cost energy payments at 90% of allowable avoided cost and considers capital and engineering costs of 427 million in December 1981 dollars This value is based on the total work order level costs of 431 million less 4 million for the switchyard and transmission line which the utility provides (Table 2) The cost also excludes the utilities construction overhead and cost of capital which are considered in the cash flows Heliostat hardware costs which account for almost 40% of total costs are based on assumed overall production of 75 000 heliostats over 10 years Table 5 details the common assumptions while Table 8 delineates specific assumptions used for the entrepreneur perspective Figure 9 indicates the nature of cash flow By the year 2000 the internal rate of return and the return on sales are within a few points of their final values but the return on net capital employed ultimately grows to 80%

Table 8. Financial Analysis Entrepreneur Assumptions

Financial

- Construction loan
  - Short-term loans until turnover
  - First loan 1982
  - Payment of interest only during construction period based on loan to date + 1/2 of current year loan
  - 65% debt 35% equity
  - 18% interest rate
  - Commitment fee at 0 005 per year of remaining loan
  - Commitment based on total loan commitment less loan to date + 1/2 of current year
- Project financing
  - 65% debt 35% equity
  - 16% interest rate
  - 10 year loan
  - Constant payment loan
  - Loan cost issuance fee at 0 006
- Discount rate
  - 20% after tax

Avoided cost payment

- Energy payment
  - Negotiated at 90% of full payment (consideration for Edision providing land interconnection facilities and switchyard hardware)
- Capacity payment (levelized 1988 dollars)
  - $240/kW/year (based on the 1985 figure escalated – not an Edision published payment)
  - 0 60 nominal capacity factor (0 56 calculated after forced outage)

On-Peak		Mid Peak		Off-Peak	
Summer	Winter	Summer	Winter	Summer	Winter
0 87	0 78	0 88	0 72	0 48	0 30

  - Capacity and availability penalties applicable in off-peak period only
  - Negotiated at full payment due

Tax considerations

- Tax credit
  - Federal – 25% (in year cost incurred)
  - State – 0%
- Tax rates
  - Federal – 46%
  - State – 9 6%
- Depreciation (partial start in 1986 balance in 1987)
  - Federal – 5 year ACRS on federal
  - State – 8 year SYD

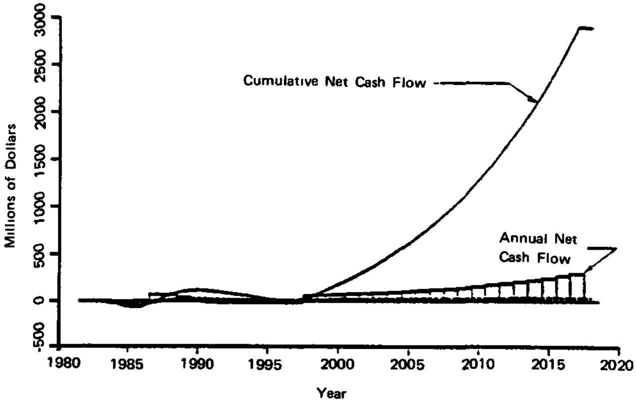


Figure 9. Entrepreneur Ownership—Baseline Cash Flow

Figure 10 indicates quick profitability once operations start, but then several years of negative net cash flow cause declining returns as the tax impact of depreciation and interest expense lessens The downward spike reflects one year (1997) when the cumulative net cash flow goes negative, again The final loan payment is made in that year ending any further negative net cash flows Capital overruns may still allow an acceptable internal rate of return (IRR) but, as implied, may extend the period of negative cumulative net cash flow by several years Underruns will maintain a positive cumulative net cash flow as well as substantially improve the IRR

Figure 11 shows the combined impact of escalation rates and the percent of avoided cost realized in revenue Profitability appears especially sensitive to the escalation rate of revenues although the

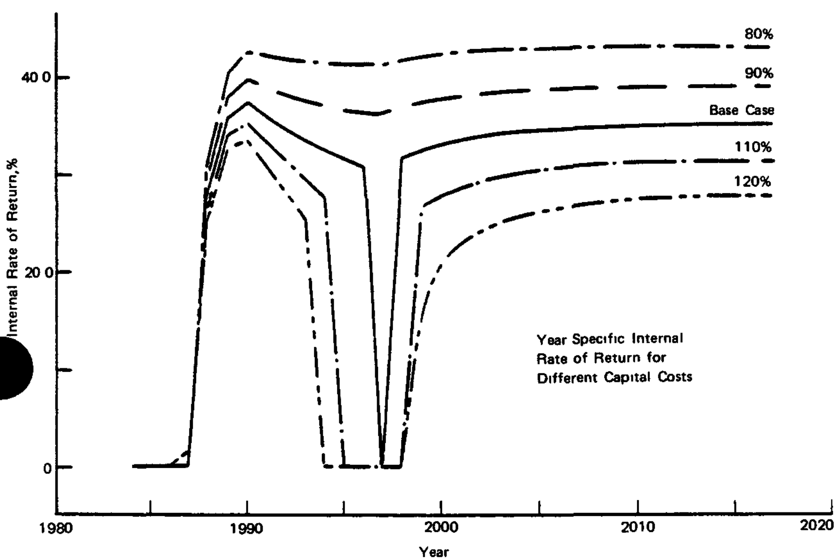


Figure 10 Sensitivity to Capital Cost

level of avoided cost revenue realized is also quite significant The figure suggests that energy cost escalation below general inflation need not discourage investors provided the power purchase contract provides revenues at close to full avoided cost

Figure 12 indicates the importance of the federal energy credit, as well as the impact if the credit is cut off before project completion The curve reflects that the energy tax credits are taken as capital outlays are made Thus, an advantage is gained as the cutoff date is extended The energy tax credit is scheduled to expire in December 1985 Extension or "grandfathering" is essential to any entrepreneural ownership of a project this size

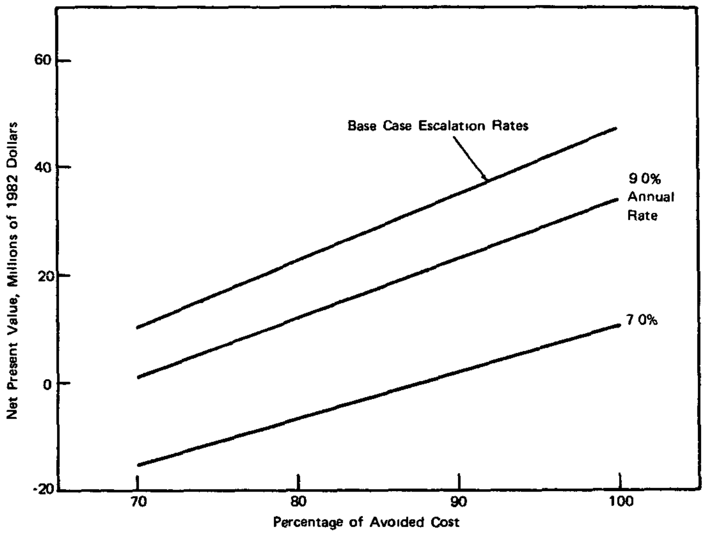


Figure 11. Sensitivity to Electricity Revenues

Section 7
RISKS AND CONSTRAINTS

Solar One provides a solid basis for the readiness of solar central receiver technology for commercial application However it does not provide specific molten salt operational experience Although there is extensive industrial process experience with molten salt for more than 40 years there are specific equipment designs necessary to meet the unique requirements of the solar plant operation The two most important items which must be addressed are the receiver and steam generator

The greatest technical risk is in the molten salt receiver Some of the risk is inherent in the scale up from previous equipment such as the 5 MW_t unit tested at CRTF and some is inherent in the high-temperature thermal cycling characteristic of the receiver operation The primary risks are that performance may be lower than expected and receiver tubes may fail prematurely This can be addressed by extra margins and redundancies as well as appropriate quality control and maintenance planning It is believed that the background and experience available will permit design and construction of that equipment for Solar 100 to proceed without unusual problems

The technology of molten salt steam generators has not been fully proven, although there is extensive experience in design and fabrication of similar heat exchangers The risk is inherent in

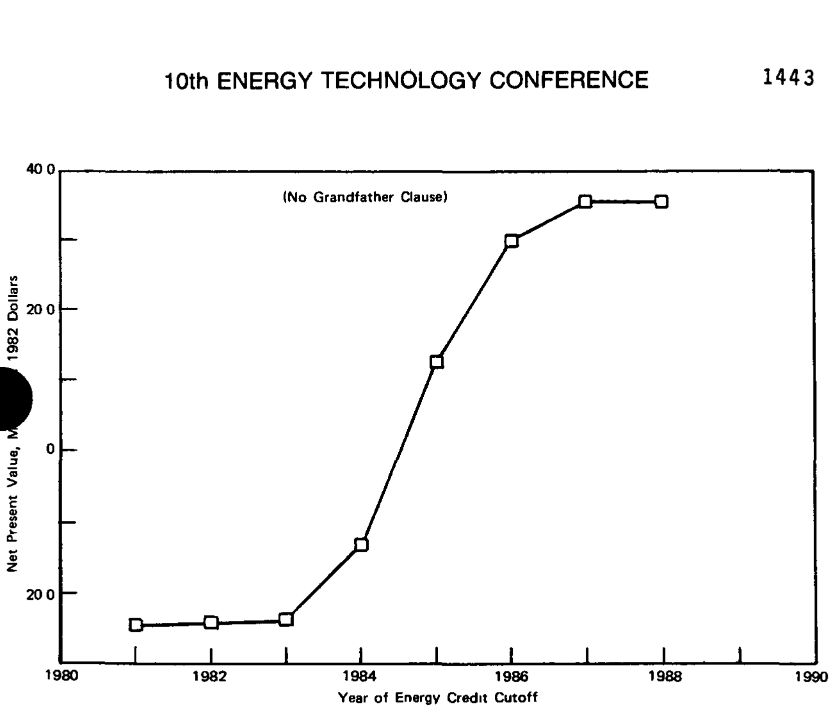


Figure 12. Energy Credit Cutoff

the scale-up and extrapolation from other equipment No specific risks have been identified The perceived risks can be addressed by extra margins and redundancies as well as appropriate quality control and maintenance planning It is believed that the background and experience available will permit design and construction of this equipment for Solar 100 to proceed without unusual problems

There are inherent risks associated with any type of new technology which must be tempered by the advantages of developing a new nonpetroleum power source The technical problems noted do not appear insurmountable, careful prototype testing and prudent and judicious engineering design should minimize the risks of nonperformance or reduced performance

Section 8
REGULATORY ANALYSIS

The permitting and regulatory cycle of the Solar 100 project can essentially be related to four agencies California Energy Commission, the California Public Utilities Commission, federal authorities, and local agencies

The California Energy Commission (CEC) has the sole authority for the certification of thermal power plants within the state of California The provisions governing the certification process are set forth in the Warren-Alquist Act (Cal Pub Res Code Sections 25500 et seq) Jurisdiction of the CEC is limited to licensing only those thermal power plants rated at 50 MW or more

Typically, the provisions require a 12-month Notice of Intention (NOI) proceeding and an 18-month Application for Certification (AFC) for licensing of a thermal power plant The NOI is a statement prepared by the applicant containing a description of the proposed project, a statement of need for the project, and a discussion of the relative economic, technological, and environmental advantages and disadvantages of alternative sites and facility proposals The AFC is the regulatory process by which a specific design at a specific location is evaluated In addition, the

Warren-Alquist Act also enables a thermal power plant with a generating capacity of up to 100 MW to be exempt from the NOI process Under this statute only an AFC is necessary, and the Commission is required to issue its final decision within 12 months of the filing date Solar 100 qualifies for this exemption, an AFC was filed with the CEC on December 1, 1981, and a final decision was provided in December, 1982

In addition to certification by the CEC, Edison is required, if it is the plant owner, to obtain a Certificate of Public Convenience and Necessity from the California Public Utilities Commission CPUC authority is limited to rate and system reliability issues However, a third-party owner does not have to file with the CPUC although CEC filing (AFC) would still be required

Generation and transmission facilities that are to be sited on federal lands will require a pe from the appropriate landholding agency No significant obstacles are anticipated at the Lucerne Site since it is already owned by Edison

Generally, the CEC authority preempts local jurisdiction, however, the regulations of local agencies must still be met No significant obstacles are anticipated at the Lucerne Site

Section 9
CONCLUSIONS AND RECOMMENDATIONS

The conceptual study investigated the technical and financial feasibility of a commercial 100 MWe solar thermal power plant The conclusions of the study follow

1 It is technically feasible to build the Solar 100 thermal central receiver plant by 1988 which would have the following characteristics
   a) 98 3 MWe net average output
   b) 489 million kWh annual energy production
   c) 60% capacity factor and 94 5% availability (excluding meteorological conditions)
2 Further receiver prototype testing and operational experience with Solar One will minimize technical risks associated with Solar 100
3 The plant has an estimated capital cost of $580 million and average operating expenses of $5 5 million (nonlevelized 1981 dollars)
4 Utility ownership would result in an energy cost that exceeds avoided costs (i e , energy cost of Solar 100 exceeds Edison's incremental rate)
5 Of the three ownership alternatives considered, third-party ownership appears to offer the most promise However, under the present provisions of PURPA such a plant would be subject to federal and state regulation
6 Although this conceptual study was essentially site-specific to Edison's requirement, the analysis also shows the technical and financial concepts developed to be applicable to most southwestern US utilities

To further pursue Edison's corporate objective of having 300 MWe of solar capacity by 1990, Edison released a Solar Program Opportunity Announcement (SPOA) on May 3, 1982, to solicit proposals for a third-party ownership of Solar 100, proposals were due September 17, 1982 Edison, therefore, hopes to have a minimum of one large solar central receiver by 1990 at or bel avoided cost to its ratepayer

The unit cost of heliostats (which account for approximately 40% of the total plants cost) will be reduced as other utilities make commitments to install solar central receiver plants Therefore, it would be beneficial if solicitation similar to the SPOA were issued by other utilities so that the generic design can be adapted to unique generation mixes and energy rates for comparison to present-day alternatives

PHOTOVOLTAIC POWER FOR UTILITY APPLICATIONS: 12 MONTHS FROM CONCEPTION TO STARTUP

THE TRANSITION FROM PUBLIC TO PRIVATE SECTOR FUNDING

John B. Cheatham

ARCO Solar, Inc.

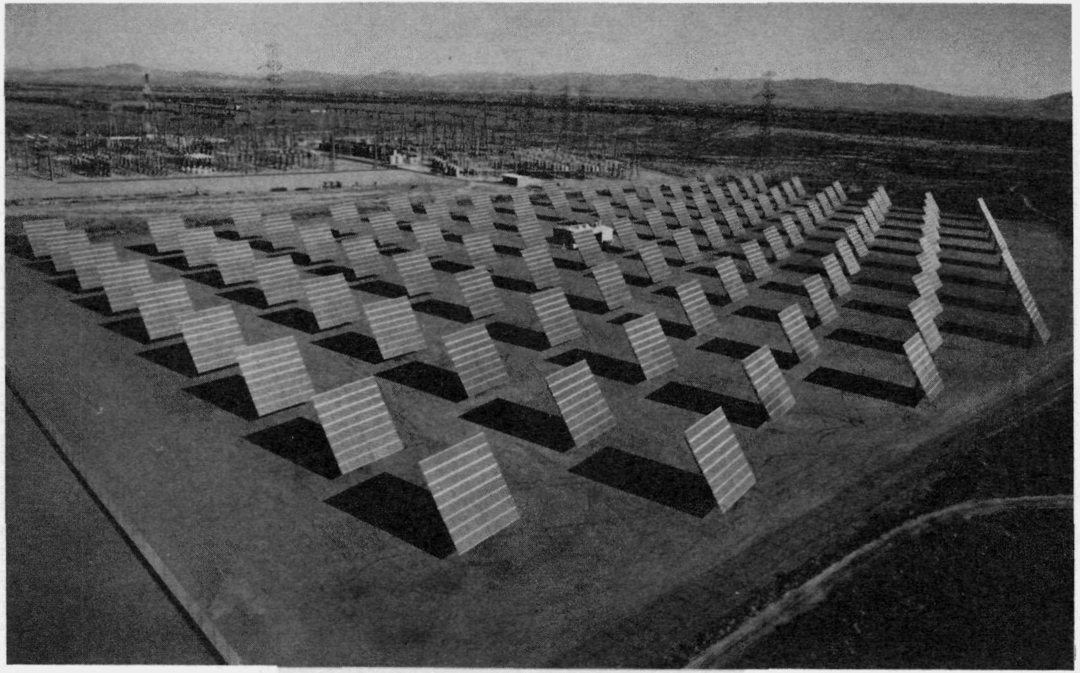
Woodland Hills, California

The ARCO Solar Photovoltaic Power Plant (One Megawatt), located on 20 acres near Hesperia, Calif., was dedicated on February 15, 1983. The plant was designed and built by ARCO Solar, Inc., the leading manufacturer and marketer of photovoltaic modules and systems in the world. (The installation is owned and operated by ARCO Solar Electric Power, Inc., a subsidiary of ARCO Solar, Inc. ARCO Solar, Inc. is itself a subsidiary of Atlantic Richfield Company, a natural resources corporation based in Los Angeles.)

Photovoltaic or solar electric modules are constructed of semiconductor diodes. When light strikes their surface, it stimulates the release of electrons that can be guided into a circuit to become a useful electric current. Originally developed to power NASA satellites, photovoltaic systems are now being put to use in a great many down-to-earth applications around the world.

This particular ARCO Solar power plant is capable of producing 3 million kilowatt-hours of electricity annually. Its rated capacity is at least three times greater than that of any existing photovoltaic system in the world.

Power from the installation is purchased by Southern California Edison (SCE), the management of which is commit-



The ARCO Solar Photovoltaic Power Plant:

One Megawatt

ted to the accelerated development of alternative and renewable energy sources in the 1980s. SCE meters the electricity produced and delivers it to customers through its existing distribution facilities. The plant produces enough electricity annually for approximately 400 average Southern California homes.

Although conventional power plant construction can sometimes take several years, the ARCO Solar installation was built in less than a year's time. This was made possible by the simplicity and elegance of photovoltaic technology, in combination with ARCO Solar's management, manufacturing and research and development capabilities.

Permits for the installation were relatively easy to obtain. ARCO Solar received fine cooperation from the San Bernardino County Departments of Building and Safety and Planning, which allowed construction without rezoning the land area, and expedited environmental approvals. There was not a great deal of environmental impact to be considered, since photovoltaic systems produce no waste products or noise, and require very little maintenance.

The power plant's successful construction and operation clearly demonstrates the capacity of the private sector to develop and fund this type of installation. There have been a number of solar projects that have experienced substantial delays. It is important to note that these delays are probably due to the heavily experimental nature of these projects, in combination with the significant restraints imposed by regulations surrounding government-funded and -managed projects. Delay is inherent in most government-managed projects due to the extensive (and often costly) review process to which they are subject.

Solar tax credits at the state and federal level are clearly the most expeditious as well as economic way for policymakers to promote the rapid development of this new technology. It is unfortunate that just at the point when these tax credits are beginning to demonstrate their fundamental efficacy and efficiency for such large-scale utility projects, that they are being brought into question by policy makers. This project, and others on the drawing board, are a clear indication of the fundamental soundness of this approach to private sector stimulation.

The project was a marriage of two technologies: ARCO Solar, Inc. photovoltaic modules and third-generation ARCO Power Systems trackers (ARCO Power Systems is a unit of ARCO Solar, Inc.). This combination is a first in the industry, and offers several advantages:

1) Arrays mounted on trackers can generate 40 percent more electricity than comparable arrays on stationary mounts, because they are optimally oriented toward the sun

at all times. (SCE has its peak power requirements in the hot summer months. This power plant provides an increase of about 50 percent compared to a fixed array in these critical summer months. Also, photovoltaic installations generate peak power on summer afternoons -- at the very time of day when there is the greatest demand for power to run air conditioners.)

2) Because of this optimal orientation throughout the day, substantially greater amounts of power are available dur early morning and late afternoon than would be generated stationary-mounted arrays. This increase in the capacity factor is an important consideration to those concerned with obtaining the maximun electrical output throughout the day, since such installations produce at full capacity for longer periods of time each day.

3) From its years of experience in the installation of stationary mounts, ARCO Solar has learned that the cost of design and installation of foundations for fixed solar arrays can be high, and site-specific work time consuming. Trackers, however, are easier and less costly to install. Fewer holes need to be excavated and no bases are needed. The foundation system is a simple hole bored in the ground, with a vertical tube grouted in the hole with cement. Thus, construction crews are able to work with simple components using familiar techniques.

Trackers are constructed of parts that are easily available: steel pipe; Butler trusses, and gear boxes. They may be assembled on-site. For this installation, supports positioned on the ground were mounted with pre-assembled panels of photovoltaic modules that had been shipped to the site. Once the panels and supports were assembled, they were raised into position and fastened to the tracker pedestals.

Construction of the power plant was completed in less than nine months, by a small crew using a minimal number of pieces of heavy equipment to prepare the site and install the equipment.

The modularity of ARCO Solar photovoltaics makes possible the construction of many different types of systems. Single modules or panels can provide power for rural electrification, transportation signals, water pumping and telecommunications devices. Arrays and groups of arrays can provide village electrification, or, in the case of this installation, serve as utility substations.

The trackers used in the power plant are based on a design used with heliostats. It is equally effective in orienting the photovoltaic arrays toward the sun. The trackers' double-axis design allows them to be both moved toward the sun during the day, and positioned for seasonal changes in the sun's elevation as well. Tracker movement at the installation is computer-controlled, allowing for automatic operation. The computer calculates the precise orientation needed at a particular time to take maximum advantage of available sunlight.

So in summary, power plants built of double-axis tracker-mounted photovoltaic arrays have a number of significant advantages:

1) There is a comparatively short lead-time from conception to startup.

2) Construction is quick as well, due to the simple nature of the tracker components and the modularity of the photovoltaics.

3) Photovoltaic installations impact the environment only minimally.

4) Photovoltaic power plants provide peak electrical output when utilities most need it in areas where the load is greatest in the afternoon.

ARCO Solar has the expertise necessary to construct a power plant such as this nearly anywhere in the world. In the future, we look forward to producing many more of these installations, on a scale as large as necessary to fill our clients' needs.

THE STATE OF WIND ENERGY DEVELOPMENT OVERSEAS

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U.S. Department of Energy

The windmill in its earliest form was invented by some unknown genius in Persia around the 2nd or 3rd century (Fig. 1). The concept was brought back to Europe by returning Crusaders in the 11th and 12th centuries although some historians opt for an independent development in the eastern Baltic. Be that as it may, it was then utilized extensively in northwestern Europe and England until the advent of steam.

It was brought to the New World in the 1600's but didn't catch on. Competition from hydropower (waterwheels) in the Northeast and low winds in the Southeast were deterrents. As important, the traditional sailcloth windmill was highly labor intensive and manpower was in short supply in the early colonies. In the mid 1800's, the multi-bladed, self-furling (automatically regulated), waterpumping windmill was developed and that ubiquitous machine played a major part in the opening up of the West providing water for drinking, cattle raising and the thirsty boilers of the early railroad locomotives crossing the plains.

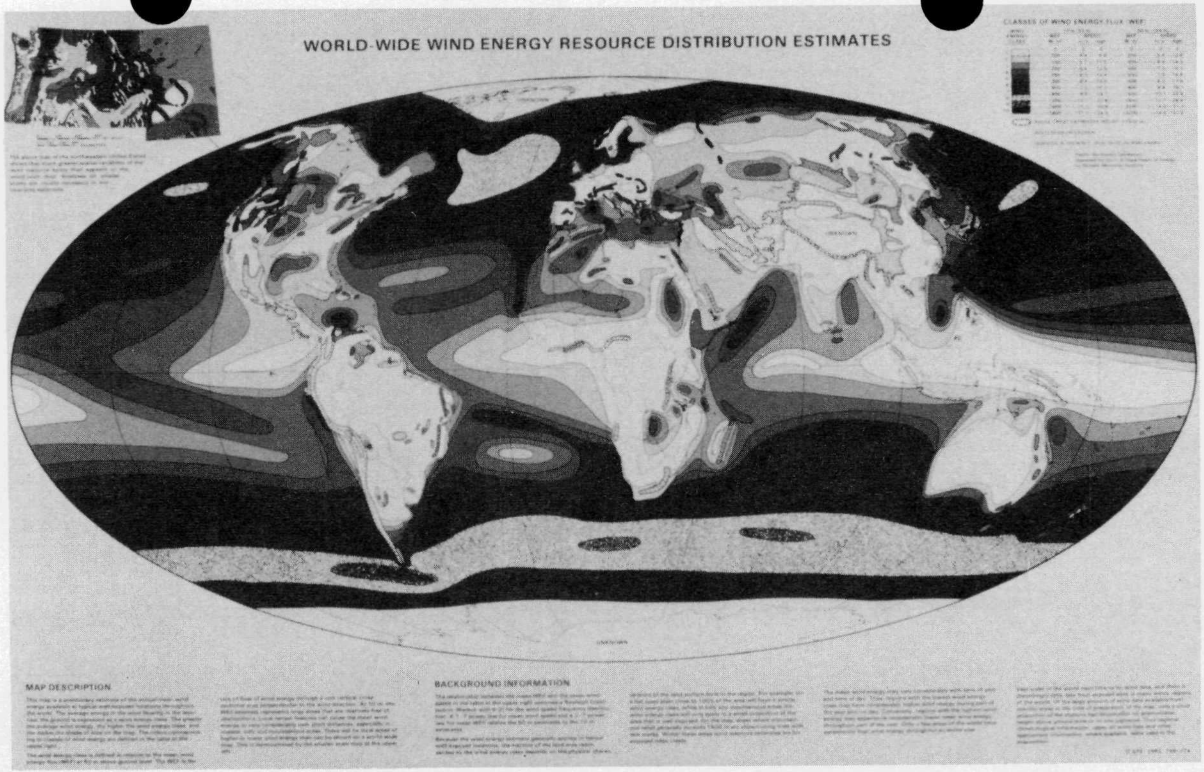

Fig. 1: World Wind Energy Map

Just before the turn of the century, Charles Brush hit on the idea of putting an electrical generator on the output shaft. (I might add that this occurred in Cleveland, not far from the present location of the NASA Lewis Research Center, a focus of large wind energy systems development.) That led to the extensive use in the midwest of the small wind electric generator in the 1920's and 30's until the advent of rural electrification.

Actually, it was the work of LaCour and Juul in Denmark in the early part of the century that initially perfected the idea and windpower was examined as an alternate to oil fired generation around the time of both world wars (Fig. 2). The development of windpower essentially stopped in the U.S. by 1940 whereas it continued in Europe albeit at a modest rate until about 1960 when the low cost of conventional energy ended the work. England, France, Germany and Denmark had been at the forefront.

There are three points to be made from this short excursion into history. Wind systems have has come and gone at intervals in history as their relative cost has fluctuated with respect to competition from conventional fuels. Second, Europe has not only the tradition of the "old Dutch windmill", but a more modern tradition of innovation and development of advanced electrical generating wind turbines. Third, and more specifically, at the time of the rising interest in alternative energy sources in the early 1970's, the Europeans had more in-depth experience on the modern wind turbine than existed in the U.S.

Thus as the U.S. program started in the early 1970's, the first "U.S." test data came from the Danish Gedser wind turbine. Since it was the only machine of the WW II era to still physically exist, a U.S.-Danish bilateral agreement was implemented to refurbish and test the machine (Fig. 3) while the U.S. was building its initial Mod O/OA series. This project also provided some insight into the 2-blades versus 3-blades question.

Denmark continued as one of the first European countries to begin testing new systems. In 1979, two 40 meter diameter, 630kW machines commenced testing at Nibe, near Aalborg in northern Jutland (Fig. 4). While both are upwind threebladed machines with concrete towers, they have a major configurational difference. Nibe A, similar to the Gedser, has basically fixed pitch blades with controllable tips and external bracing whereas the Nibe B has cantilevered full span pitch control. Each machine now has about 2500 hours of test time and thus an extensive amount of data has been accumulated.

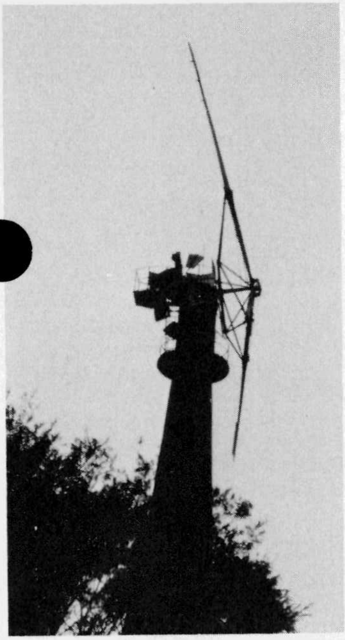

Fig. 2: 1942 FLS 90kW Danish wind turbine

Fig. 3: 1950 Gedser machine during restoration in 1977

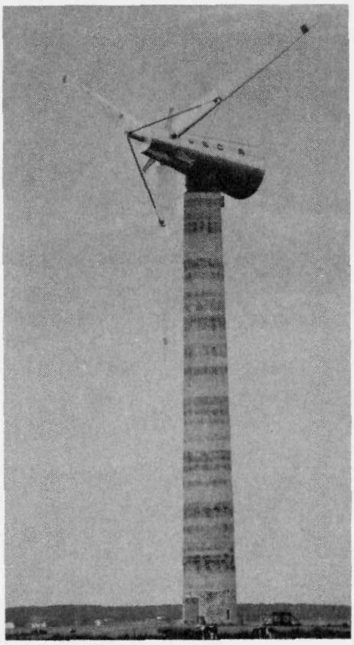

Fig. 4: Nibe wind turbine installation

TVIND WIND MACHINE

Fig. 5: Tvind wind turbine in western Jutland

A private project by a Danish experimental school led, at about the same time, to a rather spectacular achievement. The Tvind machine (Fig. 5) on the North Sea coast has a 54 meter diameter, 3 bladed downwind rotor with full span pitch control and is rated at 2MW. It is unique in that 500kW of the variable frequency output is utilized directly for building heating and the remainder is inverted to allow connection into the grid. A newer project consists of a joint venture between the Vorlund Company in Denmark and ASEA in Sweden, supported by the Danish government to continue to test the 265kW Vorlund machine and upgrade it to 340kW. The machine has dual generators to optimize output under both low and high wind conditions (Fig. 6).

Denmark is also a leading country in the development of small wind systems. A test center at Riso, Denmark has performed a similar role to our Rocky Flats Plant in providing extensive experimental data on small machines. A major difference between Denmark and the U.S. (and I am not commenting on the relative merits or appropriateness of their approach) is that the extensive renewable energy grant and tax credit program in Denmark has a requirement that the machine must receive an "approval" from Riso to be an eligible purchase, thus acting as de facto standards. The long tradition of wind systems in Denmark, the involvement of mid-sized companies (vis-a-vis very small or very large companies in the U.S.) and the relative economics in their fuel cost and tax credit environment has led to the rapid installation of Danish small wind systems. There are many hundreds of new 20-50kw systems in use on farms in that small country. Belgian and Dutch firms manufacture some on license and we are beginning to see some exported to the U.S.

Two other international agreements came into being at about the same time as the bi-lateral with Denmark and for the same reasons. An International Energy Agency Agreement on Wind Energy R&D was initiated in 1978. It consists of a series of Annexes (primarily analytical modelling and wind resource projects or tasks); eleven countries joined the basic Agreement with various countries participating in each Annex.

The second activity is the IEA Agreement for Cooperation on Large Scale Wind Energy Systems. A prerequisite for joining this agreement is a commitment to build one (or more) large wind systems and thus initial participation consisted of Denmark, the U.S.,

Fig. 6: Volund intermediate sized wind turbine

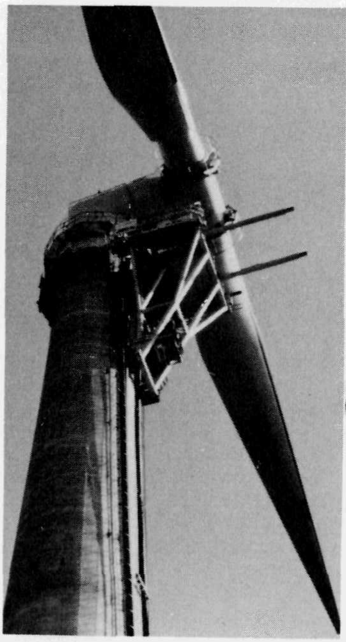

Fig. 7: WTS-3 system near Marglarp, Sweden

Sweden and Germany; the U.K. and Canada joined later and I will be discussing their systems. The Agreement involves the exchange of general information (but not design tools or design details) and test data. Thus there is reasonable guid-pro-quo as well as protection for each country's proprietary needs.

While the U.S. invested more heavily in windpower than the European countries in the later 1970's and perhaps "jumped ahead", steady progress has been made overseas and this year represents somewhat of a culmination with a number of large experimental systems reaching the test stage.

One must recognize that each country is different; each has different energy situations, different resources, different objectives and different constraints and this leads to not only a difference in program content but a difference in the technology being pursued. For example, most European countries have very high population densities and thus with the exception of Denmark discussed above, have put little effort into small individual sized wind systems concentrating on the large systems instead. For the same reason, interest in off-shore wind systems has been much more extensive in Europe, particularly in the U.K., where it represents a major theme of their program. A new IEA Annex to investigate off-shore wind power was recently signed by the U.K., Netherlands, Denmark and Sweden.

The availability of the wind resource vis-a-vis the availability of (or perceived desire to use or not use) conventional power sources has led to quite varying relative program expectations between wind power's use as an indigenous energy source versus an export product. With that in mind, let me discuss the major activities in other countries.

The Swedish National Board for Energy Source Development has taken an approach similar to the U.S., starting with a 20 meter diameter test bed (unfortunately later destroyed when a crane tipped over) followed by two parallel competing design and development contracts for MW scale systems. The WTS-3 (Fig. 7) represents a joint effort between Karlskronavarvet (a subsidiary of Swedyards) and Hamilton Standard of the U.S. The 3-MW, 80 meter diameter two-bladed downwind system is nearly identical to the WTS-4 purchased by our Department of the Interior from the same makers for tests at Medicine Bow, Wyoming. These units incorporate a number of advanced features including a delta-3 hinge, fiberglass blades and, while currently operating with a servo-driven yaw control, has the planned capability to operate in "free yaw". That is a feature common in small systems but which has never yet been successfully accomplished on large machines although the Danish Vorlund and others have attempted it and it has been tried during research tests on our Mod-O. The WTS-3 now has over 100 hours of testing since its erection in June of 1982 at Maglarp in southern Sweden and has achieved its full 3 MW output.

The competing KaMeWa machine (Fig. 8) is located on Gotland Island and is a 2MW, rigid hub upwind system of 75 meter diameter with a reinforced concrete tower and steel blades fabricated by ERNO/VFW in Germany. In some respect the KaMeWa represents a more conservative design philosophy than the WTS-3, but is does incorporate several innovative features.

The upper assembly consists of 3 subassemblies; the generator, the gearbox assembly and the rotor and the machine does not utilize a nacelle in the normal sense. The generator is mounted vertically in the tower top and is driven by a bevel gear at the output of the gearbox. A built-in hoist system runs on rails up the tower side to carry each of the three subassemblies and thus no separate crane or gin-pole is needed for erection or removal for major maintainence. This system also entered testing in the fall of 1982.

In Germany, a very high technology approach has been taken. The centerpiece Growian I (standing for Grosse Windenergie Anlage) at 100 meter diameter has the largest rotor yet built (Fig. 9). It also is a self erecting machine with the nacelle climbing the tower and the shafting being connected after it reaches the top. Several very advanced features are incorporated including variable rpm with VSCF generator to maintain high power coefficients and reduce torsional stiffness. An extensive anemometer tower network has been installed upwind to rotationally sample the entering winds. Located on the North Sea coast north of Bremerhaven and built by MAN, the 3MW machine successfully "climbed" the tower in October and first turn is scheduled for this spring.

Perhaps 25 kilometers away stands the Monopterous, 49 meter "diameter", 350kW experiment (Fig. 10) which is considered both a 1/3 scale model of a potential future 145 meter, 5MW Growian II as well as a possible intermediate scale machine in its own right. The major characteristic of a counterweighted single blade is self evident. The design argument for such a concept goes as follows: the quest for higher power coefficients, lower gearbox torque and lower material requirements requires higher tip speed ratios. This in turn leads to lower solidities and hence very narrow chord blades and to

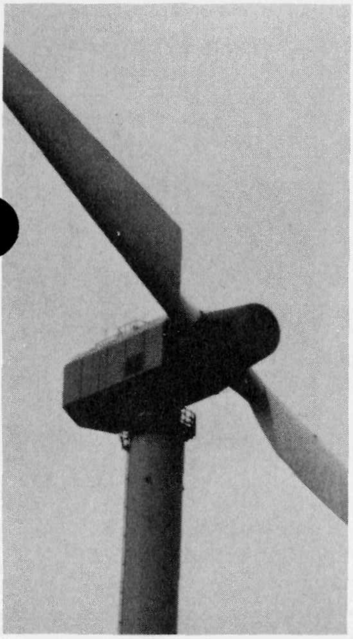

Fig. 8: KaMeWa machine on the Island of Gotland

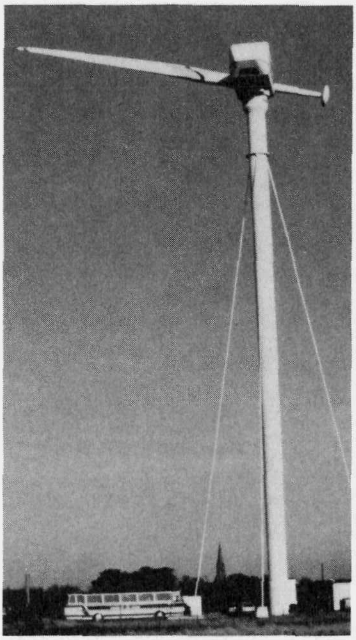

Fig. 10: Unique 1-bladed Monopterous wind turbine

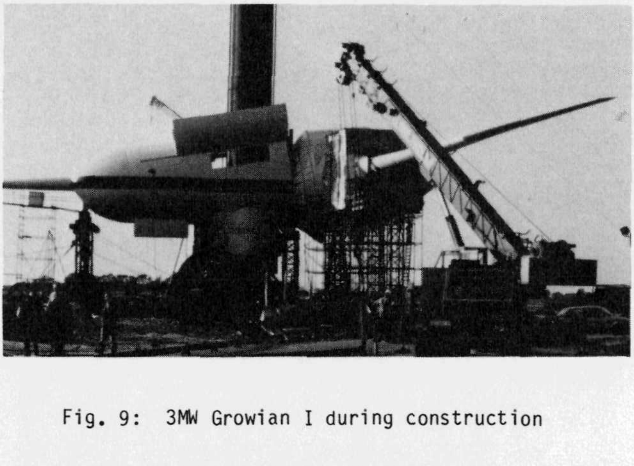

Fig. 9: 3MW Growian I during construction

maintain aerodynamic efficiencies, to proportionately thin airfoils. These run into design difficulties in maintaining adequate spar strength. This trend has led the number of blades to decrease from the older multi-bladers to four, then three, in most cases to two and here to one blade. I don't think the trend can go much further. Whether the expected performance advantages can outweigh the asymetrical dynamic conditions is yet to be determined. Built by MBB and completed last fall, the full testing program is also scheduled to start this spring.

The privately developed 52 meter, 265kw Voith machine has been under test for some time in southern Germany and with a tip speed ratio of 16, represents about the furthest in that direction that a 2 bladed machine has yet attempted.

For the sake of time, I must now discuss other developments more briefly. The Canadian program has concentrated almost completely on the vertical axis Darrieus type systems. A 200kW research unit has been under test at the HydroQuebec test facility on the Magdalene Islands in St. Lawrence Bay for several years. While at one point it was destroyed (due to human error) it was rebuilt and the results obtained were sufficiently positive that in February 1982 authority was obtained to proceed with Aeolus. Presently in the design stage, Aeolus will represent the first MW class Darrieus. Several other Darrieus machines from 5kW to 500kW are in various stages of design and testing by private firms in Canada.

In the United Kingdom there are, in effect, two programs. The U.K. Department of Energy and the North of Scotland Hydro Board are funding the development of a 3MW, 60 meter diameter machine for installation in the Orkney Islands. While the initial preliminary design arrived at a very stiff 2-bladed system, sufficient time passed pending approvals that a major evolution has been occurring and it is not clear at this time what the final configuration will be, but much softer systems with teetered hubs are under investigation. The prime contractors, in order to both gain development experience and potentially meet the intermediate market are building a 250kw scale machine and construction is presently underway at the samed Burger Hill site in the Orkneys. Several small and vertical axis machines are also under development.

In parallel, the Central Electricity Generating Board (CEGB) has begun a program to investigate wind power by purchasing units of machines already in existence for test and evaluation. The first competition, for an intermediate machine, was won by WTG of New York and one of their 200kW machines similar to their first Cuttyhunk Island, Mass. and other installations in the U.S. and Canada, started operating in 1982. It is, by the way, based on the general dimensions and configuration of the Danish Gedser mentioned earlier. A similar competition is expected this year for a MW class machine.

Some recent activities in other countries include a 25 meter, 300kW test bed at Pettin, Netherlands and approval was recently obtained for a much expanded program including a multi-unit 10MW cluster; a 100kW test unit is operating in Japan (Fig. 11); field testing of approximately a dozen 5kW to 60kW machines is occuring in Ireland including a direct heat (butter churn) approach; vertical axis research in China; France has a 100kW unit in test; Italy has an array of ten 50kW machines in a test cluster in northwest Sardinia and is embarking on the design of a MW scale system; numerous small scale projects in or for developing countries are underway.

Fig. 11: Japanese 100kW test bed

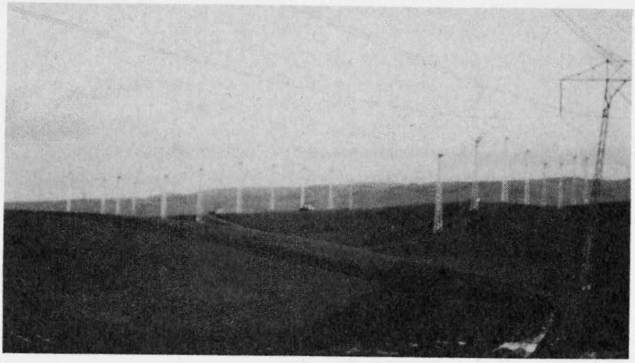

Fig. 12: One of several "farms" of 50kW machines, Altamont Pass, Calif.

Fig. 13: Cluster of three 2.5MW Mod-2 wind turbines, Goldendale, Wash.

With that brief "grand tour", let me conclude with some summary observations. Essentially all machines, here, there, big and little have run into various development problems but their resolution and progress has been steady. If I can also make a, perhaps over-simplified and certainly personal, analogy; Sweden appears to be making Volvo's and Saab's, Germany-Mercedes, DenmarkDatsuns and the U.S.-Chevrolets. What I mean, and what is obvious from the photographs, is that the effects of configuration variables is certainly not yet clear with just about every combination and permutation of blade number, rotor location, and geometry being represented. A major more specific difference between Europe and the U.S. is that with the notable exception of the Voith-Hutter machine, European systems tend to have much higher tower to rotor diameter ratios--or rather U.S. machines have optimized toward larger rotors on shorter towers. While I believe that the U.S. is pretty much ahead of the world in both small (Fig. 12) and large (Fig. 13) machine technology, it is also clear that major activities and competition is occurring world-wide.

The next two years will represent a very exciting time as hard test data replaces paper studies and it is not yet clear which concepts will dominate the future technology of windpower. What is clear is that serious interest, in what was just a few years ago an area of perhaps benign neglect, is now world wide and that in the appropriate regions and applications wind power may again, as it was in the past, be extensively utilized as a significant source of energy.

DEVELOPMENT OF THE WIND POWER GENERATION OPTION

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ABSTRACT

Electric utility industry activities in wind power have increased significantly in recent years due to encouraging results which have emanated from various federal and privately funded research and development programs. This paper discusses the technological status and prospects of wind turbines for electric utility applications. A summary of utility activities is given. The wind power program of the Electric Power Research Institute is also discussed.

INTRODUCTION

Results from major wind turbine field experiments during the past few years have been encouraging and have significantly improved the understanding of the future research and development requirements for evolving a viable utility power generation option. This generation option could ultimately be of significant value as a fuel saver in windy areas with ample site availability. However, significant improvements in cost and performance, relative to the current state of the art, are still prerequisites to widespread use of wind turbine technology. Continuation of a well-paced research and development program in the next few years will be necessary in order to achieve the ambitious goal of evolving a generation technology that is cost-effective, proven to be technically sound, and available for widespread deployment as early as the 1990's.

HISTORICAL PERSPECTIVE

The rapid tempo for wind turbine research and development during the past few years has been established by the federal program in a series of progressively more advanced wind turbine experiments. Both horizontal-axis and vertical-axis machines have been under development. The premiere field experiments in the federal program during recent years have been the four MOD-OA wind turbines. These machines have produced a wealth of performance information.

From a historical viewpoint, the MOD-OA program is widely regarded as the most successful horizontal-axis wind turbine research and development program to date. This program was managed by the NASA Lewis Research Center for the U.S. Department of Energy (DOE). These machines are each rated 0.2 megawatts for an 18.3 mph wind speed at 30 feet above ground level. These machines were located in Hawaii, New Mexico, Puerto Rico and Rhode Island. As of June 30, 1982, these machines had collectively produced nearly 3700 MWh of energy in over 38,000 hours of synchronized operating time. Although last to be installed, the unit in Hawaii produced the most energy. This machine's relatively good performance stems from the excellent wind resource availability in Hawaii and from the fact that this unit incorporated a number of improvements relative to the three other MOD-OA machines.

The MOD-OA machines are currently the only modern experimental wind turbines for which there is a long-term history of performance in applications to bulk energy supply in actual utility systems. NASA has attained all of its primary objectives in this program, and the machines have been shut down. Although the ultimate disposition of all the MOD-OA machines has not yet been decided, the more advanced, megawatt-scale MOD-2 machines are now the premiere federally-sponsored wind turbines. However, before leaving the MOD-OA program, its page in the history of wind turbine research and development warrants additional recognition. The program's major achievements were associated with verification of the durability of new low-cost rotor blade concepts, validation of analytical codes, clarifying the requirements for wind turbine compatibility as a bulk power source in utility networks, and providing baseline data on control concepts, component reliability, and overall machine performance. Thus, the design work on more advanced machines has benefited significantly from insight gained in the MOD-OA program. Finally, the field experiments with these early research machines have laid groundwork and set precedents for activities in the burgeoning test programs of more advanced wind turbines.

CURRENT STATE OF THE ART

The current state of the art in horizontal-axis wind turbine research and development in the United States is represented by the 2.5-megawatt MOD-2 and the 4-megawatt WTS-4. The MOD-2 was developed by Boeing Engineering and Construction Company (BEC) under a DOE-funded program managed by the NASA Lewis Research Center. Five MOD-2 machines have been recently constructed by BEC. Three of these machines were constructed under DOE sponsorship at the Goodnoe Hills site near Goldendale, Washington, with support and cooperation of the Bonneville Power Administration. The fourth MOD-2 was constructed for the U.S. Bureau of Reclamation near Medicine Bow, Wyoming. The fifth unit was constructed for the Pacific Gas and Elecric Company at a site in Solano County, California. This fifth MOD-2 has a cutout wind speed of 60 mph as opposed to 45 mph in earlier units.

The WTS-4 is a competing horizontal-axis wind turbine design developed by Hamilton Standard, a division of United Technologies Corporation. The first prototype was recently constructed by Hamilton Standard for the U.S. Bureau of Reclamation near Medicine Bow. A number of other U.S. industrial sponsors are designing or developing prototype advanced horizontal-axis wind turbines, but none of these efforts has progressed as far as the MOD-2 or WTS-4. The largest known machines, under design at this time by the General Electric Company and BEC, are the MOD-5A and MOD-5B, with expected ratings in the range of 7.0 to 7.5 megawatts. The WTS-4 and five MOD-2 machines are on the threshold of test programs aimed at evaluating their performance and their operation and maintenance requirements. These test programs are also expected to identify key research and development activities for advancing the state of the art and developing machines with cost and performance characteristics that are suitable for widespread applications.

The state of the art in vertical-axis wind turbines is represented by the 17-meter, 0.1-megawatt Darrieus machine developed by Sandia National Laboratories. A few industrial organizations are developing and testing similar machines. At this time, the technology development and long-term testing of vertical-axis machines have not progressed as far as those for their horizontal-axis counterparts, and the prospects for vertical-axis machines in utility applications are not as well understood. However, some small vertical-axis machines have been successfully deployed in other applications such as water pumping.

Experts in the field of wind power believe that it is desirable to develop the largest feasible multimegawatt machines for most utility applications (especially for typical good sites with large open land areas and uniform wind flow). However, some specialized situations are also expected in which unusual site topography or some siting constraint would mandate use of submegawatt wind turbines. For example, the terrain could be so rough that it is not possible to transport and construct a multimegawatt machine. However, the following general advantages are expected to result in a lower cost of energy from the larger machines when the technology matures:

- Increased energy capture and better use of typical good sites.
- Lower operation and maintenance costs.
- Better safety and security.
- More practical coordination, control and dispatch of units in a generating station.

It is noteworthy that currently only relatively small wind turbines are available to the investment community. Hence, to take advantage of significantly attractive tax incentives for developing wind power generation, some developers have begun investing in clusters of these smaller machines. At this time, there is not sufficient operating and performance experience available to evaluate the merits of this approach to bulk power supply, but some experience of this kind may be accumulated over the next few years. However, the experience may not be made generally available by the wind power developers in many cases. In other cases, the instrumentation and measurement will be inadequate to fully evaluate performance.

UTILITY INDUSTRY ACTIVITIES

Utility participation in wind power development is essential if the technology is to make a significant contribution to overall energy supply. Economies of scale, distances between good wind turbine sites and most population centers, space requirements, and maintenance demands make utilities the logical primary market. In general, wind power's greatest potential value is in displacement of fuel consumption during windy periods, rather than displacement of planned generation capacity. Under normal operating circumstances, a utility would preserve its most expensive fuels, typically oil or gas, during windy periods. Utilities that have high dependence on these costly fuels and are in or near windy areas are promising early markets for wind power development. Because wind is intermittent, little or no credits for capacity displacement are likely to be realized from the installation of wind-powered generating stations. However, if the cost of wind turbines declines enough, the fuel displacement value of the technology may be sufficient to result in its economic viability independent of credits for capacity displacement.

Utilities are involved in wind turbine field experiments, negotiation of energy purchase agreements with independent developers of prospective future wind turbine clusters, or in some cases doing both. Other areas of utility activity in wind power include planning and siting studies.

ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PROGRAM

In the next two years, EPRI's wind power program will emphasize participation in key test and evaluation programs for state-of-the-art wind turbines in partnership with cosponsoring utilities and wind turbine developers. The overall objective of EPRI's wind power program is to develop a viable generation option for use by the utility industry as a fuel saver in diversifying future generation expansion. Participation in the key wind turbine test programs will support attainment of this objective by enabling EPRI to:

- Maintain a firm understanding of the status and outlook for wind turbine technology.

- o Define key follow-up research and development activities for advancing wind turbine technology in terms of improved performance and lower cost.

- o Develop a technical information base.

As a follow-up to these test programs, EPRI cosponsorship of advanced wind turbine research and development programs in subsequent years is being considered as a next step toward attainment of the stated overall objective.

In parallel with the near-term test programs and follow-up advanced machine development, EPRI will continue existing broad technology assessments to maintain a perspective on key complementary wind turbine research efforts throughout the world. This broad-based information will be a vital factor in planning, execution, and evaluation of the new activities. State-of-the-art horizontal-axis wind turbines are currently under test in Sweden and West Germany. Additional programs are being planned in Denmark, France, Italy, the Netherlands, Norway, and the United Kingdom. A major effort to develop vertical-axis machines is taking place in Canada.

OUTLOOK

Although the rapid wind turbine technology advances achieved during the past few years are good reasons to be enthusiastic about the long-term promise of wind power generation, the job is far from complete. Significant improvements in cost and performance, as may be achieved through additional technological advances, are needed to make wind power competitive in widespread utility applications. EPRI's planned emphasis in the next few years on key test programs with follow-up development of advanced machines is expected to help maintain momentum established by the DOE program in recent years. This EPRI activity will also provide both coordination of key individual test programs and an efficient means for direct involvement of the utility industry in the wind turbine research process. If this process is carried to completion and its objectives are attained, wind power could begin making a significant contribution to our international energy requirements prior to the end of this century. Wind power is not going to be the singular solution to the problems of future energy supply, but it is one of a blend of technologies that collectively may be the solution.

Small Consumer-Owned Wind Machines and Associated Interface Problems

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Introduction

The oil embargo of 1973 stimulated intense public interest in alternative sources of electric energy including wind energy. At that time there were several manufacturers of stand-alone wind-electric systems for rural and remote applications. The federal government, primarily via ERDA (later DOE), then began financing feasibility and engineering studies and prototype construction of large and small wind electric systems--primarily for interconnected applications where the units operate while connected to utility lines. It takes at least 15 feet of shelf space to store the resulting research reports which provide the research, methods and computer codes needed for well-engineered small and large WECS (wind electric conversion systems). There are some unanswered questions--especially concerning WECS-utility interface problems when WECS output is a significant fraction of local load or system generation capacity--but the major work has been done.

WECS Market

What has happened in the small WECS (SWECS) marketplace during this decade of R and D activity? More than 80 manufacturers have announced or delivered WECS with at least 50 currently active--in development or production. Many firms have left or entered the market with SWECS models of various configurations. The author estimates that at least 20 firms are now delivering production SWECS for consumer application. At the October 1982 American Wind Energy Association Meeting, a market research firm called Strategies Unlimited gave the following estimates of the number and value of WECS sold as:

Year	WECS Sold	Dollar Value in Millions
1979	1000	3.9
1980	1700	6.7
1981	2400	13.7
1982	2500	21.6

The increase in unit price not only reflects inflation but also an increase in the capacity and thus price of the WECS sold as buyers found that larger machines are more viable in most applications. "Wind farming," not addressed in this paper, is the dominant force in the large SWECS or small WECS market. Nevertheless, a significant number of SWECS are purchased by individual consumers who use them as a dispersed generation source interconnected to their utility. Most are installed in rural and semi-rural locations and a minor fraction of these had on-site wind data available as a basis for a purchase decision.

Reliability

Field tests by the author [1], various utilities, public service groups, the U.S. Department of Agriculture and the Rocky Flats Wind Test Site (mostly DOE financed) all indicate that the manufacture, installation, and maintenance of SWECS is easier to plan than to implement. It is difficult to reproduce in a factory the hostile environment of an economic wind site and extensive field experience and resultant modifications will be needed before SWECS designs have reasonable MTBF's (mean time between failures). One year is a reasonable target and most installations have several outages per year. A satisfactory MTBF isn't enough because the mean time to repair (MTTR) must also be small (several days) so significant energy production isn't lost. Current SWECS down times in the author's current monitoring program range from a week to months. Satisfying reasonable MTBF and MTTR criteria requires a field service structure with fast feedback to the manufacturer, trained personnel, and rapid accessibility to repair parts. It appears that the several currently-successful SWECS manufacturers realize this and it may be no coincidence that most of these are partially owned or backed by large established industrial firms. A majority of outages are caused by lightning, blade or bearing failure, inverter problems and brake failure. Some manufacturers and installers underestimate loads from high winds which cause many of the mechanical failures and some of the electrical ones (overcurrent). Nevertheless, several existing models are within reach of the reliability criteria suggested and reliability will likely improve as field experience accumulates. The experience gained by testing and engineering programs such as those at Rocky Flats will also help manufacturers and installers. Improved reliability and a reasonable system life will be necessary for continued growth in the number of operating SWECS.

Economics

An economic SWECS installation depends upon the following conditions:

- The wind regime in the area.
- The wind velocity over the rotor disc at the particular site. (High and relatively steady wind is best and usually requires towers over 80'.)
- Adequacy of installation of footings, tower, nacelle and wiring.
- Performance characteristics of the SWECS chosen.
- SWECS reliability
- SWECS lifetime (20 years will be hard to reach).
- System fixed (net purchase) cost.
- System repair costs (strongly related to reliability).
- Utility buy-back conditions.

Since economic SWECS installations are so strongly site dependent, general statements regarding economic operation are unreliable. None of the current installations in Michigan are likely to be economic but a properly-sized SWECS with a current installed net cost of $1.00 per average annual kWh of A-C output, a lifetime of 20 years, and a utility rate of $.10 per kWh will come close. See [2] for programmable calculator methods of estimating economics of SWECS. To date, the better Michigan installations are running about $2.00 installed cost per annual kWh output. However, one instrumented coastal site in a state wilderness area has a measured wind regime which would likely yield an economic site given the target reliability and lifetime criteria. Even if available for development, this site is too windy and sand-blown to be habitable.

Interface Requirements

It isn't enough for an interconnected SWECS installation to be economic--it, and any other SWECS in the same area, must not degrade the quality of service to other utility customers. The utility has a regulatory obligation to deliver a homogeneous product to its customers and this is maintained by specifications on fluctuations of voltage magnitude and harmonic content (under 5%). The utility is also obligated to protect its customers, personnel and equipment during load and system disturbances and outages. This protection requirement is complicated by the presence of distributed generation (as from SWECS, small hydro, photo-voltaic arrays, steam cogeneration) on its distribution lines. When distributed generation is present, the utility alone cannot provide all necessary protection and so utilities require SWECS installations to include some of the protection functions onsite. The list of interface or interconnection problems [3,4,5] is longer than the solution list [4,6] but most can be solved in situations where SWECS exported power to the utility is a small fraction of feeder load (small "SWECS penetration"). Various state public service commissions, the AWEA, and the IEEE have drafted interconnection regulations and suggested standards which are reasonably consistent in their technical (as opposed to buy-back) requirements. The AWEA standards are now at the committee level in the ASTM process.

Although the safety-related requirements are usually well-accepted, there are several technical interconnection problems and associated requirements which are not. One is related to the variability of wind velocity and the others to the nature of the electrical source in the SWECS and all increase with penetration.

- Unless battery storage (inefficient) is used, A SWECS immediately converts wind velocity fluctuations, which are large at most sites, into large fast power fluctuations. No residential and few industrial loads, and no other generation source, has such extreme fluctuations [1]. The standard deviation over an hour of these power fluctuations typically exceeds 1/3 the average power over that hour. The fluctuations often induce corresponding voltage variations of several per cent. The phenomena is likely to cause customer annoyance at high penetration levels.

- All induction generator and many inverter SWECS require reactive support ("out-of-phase current") from the utility. It is drawn in the former to maintain the magnetic field in the generator and in the latter due to triggering of the inverter semiconductors. It is often described by the concept of power factor. When a utility supplies <u>only</u> out-of-phase current, the power factor is 0 and when <u>all</u> current is in phase (as with resistive heating) the power factor is 1. It can be explained using an example where an induction generator SWECS exactly matches onsite power demand. In this case *no* energy is being sold to the site by the utility and the watt hour (billing) meter isn't moving. Nevertheless, an ammeter placed in the service wiring will indicate a value (typically roughly equal to the magnitude of current the SWECS is producing) which is the out-of-phase excitation current. The power factor is now 0 at the interconnection. <u>The problem is that the utility must supply the system losses that providing this current entails and do so without receiving any revenue since the billing meter isn't moving.</u> Providing only reactive current can also unbalance system protection devices if penetration is high. Normal power factor on distribution lines is .9 and the costs for the corresponding exciting current are included in the normal energy charge.

- Inverter SWECS (which are used with variable speed rotors) generate significant odd harmonics [1,3]. These, if large enough, not only interfere with nearby AM radio receivers and rural telephone lines but also cause overheating of nearby motors and distribution transformers. A recent study [7] indicates that most harmonics are injected into the utility system (exported). Again, the problem severity increases with penetration. Measurement and amelioration methods for harmonics are complex and relatively expensive, and more work is needed in this area. Improved inverter technology will help.

<u>Recommendations</u>

This review of SWECS design, installation, economics, reliability and interconnection effects clearly indicates that a successful interconnected wind system is a significant engineering accomplishment. Although adequate engineering R and D results are available for most design problems, the author believes that field experience to date indicates:

- A performance and certification organization is needed on a national scale since small utilities cannot afford comprehensive testing and mamufacturers need performance criteria that don't vary much by location and utility. An institutional arrangement between organizations like UL and Rocky Flats is an obvious possibility.

- Reasonable (to SWECS owner, utility, and neighbors) interconnection requirements are needed. They must allow for site and utility differences while not burdening manufacturers with conflicting requirements and costly unneeded control devices. A modular plug-in control panel where various relays can be inserted is one possibility and a microprocessor interface controller is another. They should be included in the SWECS installed cost.

- Utility distribution engineers need portable and easily-operated instruments to assess the interconnection effects discussed in the previous section.

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