GEOPRESSURED-GEOTHERMAL ENERGY DEVELOPMENT: GOVERNMENT
INCENTIVES AND INSTITUTIONAL STRUCTURES

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CHAPTER I

OBJECTIVES, CONCLUSIONS, AND METHODOLOGY

A. OBJECTIVES

On July 1, 1978, the Center for Energy Studies (CES) of The University of Texas at Austin (UT), under sponsorship of the Division of Geothermal Energy (DGE), U.S. Department of Energy (DOE), initiated a study of the potential impacts of various federal incentive programs on the commercial development of the Texas Gulf Coast geopressured-geothermal resource. The objective of this study was to provide DGE with information and analysis which would assist in the development of incentive programs which would promote timely, efficient, and economic development of this potential energy resource. More specifically, the purpose of the study was to project the probable nature of resource development under the present incentive structure and to examine how this development might be changed by different incentive mixes. The study, completed on August 31, 1979, focused primarily on the institutional structure that might result from various possible incentive programs.

B. PRINCIPAL CONCLUSIONS

Based upon the results of this study the following major conclusions have been drawn:

1. Governmental programs which reduce the uncertainties associated with resource development will be more effective in the near term than incentives that improve potential project returns. Based on extensive consultation with representatives of the private companies most likely to develop the geopressured-geothermal resource, i.e., energy companies, gas transmission companies, electric utilities, and large energy users, as well as those most likely to finance this development, it appears that the primary reason for their hesitancy to invest in resource development lies in the uncertainties associated with resource production and utilization. These uncertainties involve the nature, extent, and probable life of the resource; the temperature, salinity, and methane content of the geothermal brine; the costs and operating characteristics of surface equipment; and possible legal and regulatory constraints. Incentive programs which improve expected project profitability (e.g., special tax provisions, production credits, low interest loans) will encourage development if offered in sufficient magnitude; however, it appears that before reasonable incentives of this type will be effective, much more information about the resource will be required so that potential developers can assess the probability that an expected economic return will, in fact, materialize. The DGE well drilling and demonstration program is specifically oriented toward providing this information and, therefore, appears particularly appropriate to current needs.
2. The incentives provided by 1978 national energy legislation markedly increased the commercial attractiveness of the geopressured-geothermal energy resource. However, energy property tax credits and the geopressured methane percentage depletion allowance should be extended beyond their current expiration dates, and additional incentives specifically directed to the geopressured-geothermal resource should probably be offered, if the resource is to be developed commercially during the 1980's. Though less important than support of research, development, and demonstration programs, government sponsorship of the following new risk-reduction incentives would most encourage geopressured-geothermal development:
 - exemption of geopressured methane from pipeline curtailment plans
 - liberalization of pipeline certification to transport user-owned geopressured methane
 - establishment of a forgivable loan program for reservoir exploration and confirmation
 - establishment of an insurance mechanism by which developers could obtain complete indemnification against losses caused by subsidence or damage to subsurface mineral formations.

Expected value incentives which would most encourage development are:

- geopressured methane and, possibly, geothermal heat production credits
- 5-year depreciation of geopressured-geothermal energy utilization equipment
- authorization for utility pass-through to rate payers of geopressured-geothermal R, D, and D expenses
- if a "windfall profits" tax is imposed on sales of certain domestic crude oil, exemption from that tax of profits re-invested in geopressured methane development.

Our analysis of these incentives is based almost entirely upon the degree to which they would encourage participation of private industry in resource development. Government policy makers should also examine these incentives in the light of larger societal issues such as: the degree and period of government involvement in private business affairs; the cost of these incentives to the government; the visibility of that cost; and the extent to which these incentives would or should give geopressured-geothermal energy a competitive edge over other unconventional energy sources.

3. A given incentive will not affect all potential participants in resource development equally. Differences in corporate and financial structure, regulation, and methods of resource utilization will cause the degree of encouragement given by a particular incentive to differ among industry types. Government policy makers should be cognizant, therefore, that any incentive will not only affect the pace of resource development, but also will influence which parties choose to become involved in that development.
4. At least through the mid-term, the institutional structure for commercialization of the geopressured-geothermal resource will be based on utilization of its methane component. This structure will likely be comprised of some mix of the following four development profiles:
 - production of methane by a petrochemical firm for use as feedstock or boiler fuel
 - production of methane by a gas pipeline company for sale
 - production of methane by an integrated oil and gas producer for sale and/or internal use
 - production of methane by an electric utility for use as boiler fuel.

The profile which will appear at a particular reservoir will depend upon local conditions, so that all four profiles may exist simultaneously at different sites. It appears that any energy produced from the enthalpy of the geopressured-geothermal fluids will be used for brine reinjection to enhance long-term methane production.

5. There is little probability of direct use of geopressured-geothermal energy for process heating or chilling in the near future. There is considerable interest on the Gulf Coast in new, low-cost energy sources; however, the relatively low temperature of geopressured-geothermal fluids, the difficulty of long-range transportation, the existence of unused low-grade "waste" heat, and the large capital costs associated with the heat exchangers required to use the fluids discourage the near-term process utilization of geopressured-geothermal heat. Nevertheless, continuing increases in fuel prices, restrictions on the use of conventionally produced methane, and demonstration of cost effectiveness in a practical situation might, in time, result in direct heating or cooling use.

C. METHODOLOGY

C.1. General

The study was conducted in three phases. First, the present status of various elements of geopressured-geothermal program was examined in depth. Next, projections were made as to how that program might develop if the present incentive scheme remains essentially constant. Finally, estimates were made as to how these projections might be altered by possible new incentive programs.

C.2. Present Status

Before analyzing the geopressured-geothermal program status it was necessary to define as accurately as possible the nature and significance of the resource. The Bureau of Economic Geology of The University of Texas at Austin has been examining the Texas coastal zone for several years to identify and characterize probable reservoir areas. During the past year a test well was completed in the Brazoria County area which has given some new insights into the nature of the resource; however, detailed information on even this single reservoir area awaits further testing of the well. A brief description of the resource and the uses to which it might be put is given in Chapter II.

The next step in examining the present status of the geopressured-geothermal program was to review the history of the program to date. To this end, records of past conferences, research reports, minutes of advisory council meetings, monthly progress reports, records of private grants, and other similar documents were carefully examined. Personal interviews were conducted with key program personnel and formal questionnaires were sent to all organizations which had been represented at any geopressured-geothermal conference or who had otherwise indicated an interest in the program. Based on this information a detailed description of the present institutional structure of the Texas Gulf Coast geopressured-geothermal activities was drawn. This description was forwarded to program participants for review and comments and the amended version is presented as Chapter III. Brief statements of the roles of participants not discussed in this chapter are given in Appendix A.

C.3. Projected Future Development Under Present Incentives Program

In projecting the probable institutional structures that might develop if the present initiatives program continues, three tasks were undertaken. In order these tasks were: (1) a review was made of major potential developers; (2) the presently existing incentives program was examined in detail; and (3) patterns of probable resource development were projected.

In analyzing the major potential developer, i.e., integrated energy companies, independent gas producers, gas pipeline companies, electric utilities, and energy-intensive coastal industries, emphasis was given to organizational framework, capital structure, regulatory restrictions, tax status, and historic willingness to accept risk.

The analysis of the natural gas industry is given in Chapter V, the analysis of the electric utility industry is given in Chapter VI, and the analysis of potential large industrial users is given in Chapter VIII and Appendix C. In addition an analysis of regulatory bodies which might play a role in resource development is given in Chapter VII.

On completion of an initial examination of these factors, it was believed desirable to contact the involved parties directly to verify preliminary findings. The two major vehicles for accomplishing this verification were a meeting of representatives from major possible participants in December, 1978, and a mail survey of smaller possible industrial users in the spring of 1979. In addition to these formal mechanisms, a number of informal meetings were held with various possible participants. An executive summary of the December 1978 meeting is given in Appendix B and the results of the industrial users survey included in Chapter VIII.

In order to project the probable nature of geopressured-geothermal resource development, given continuation of the present initiative structure, it appeared necessary to: (1) determine the relationships among investment decisions, risks, and projected rates of return and (2) define the present incentives to geopressured development. The latter point became particularly relevant because the 1978 federal energy legislation was enacted during the period of this study. A brief discussion of investment risk criteria is given in Chapter IV and an overview of present incentives available to geopressured-geothermal resource development is given in Chapter IX.

Based on the above information, analyses were made of the major factors that would affect the decisions of each of the major participants to invest in geopressured-geothermal development. Taking these factors into account, projections (profiles) of the most probable future scenarios for resource exploitation were developed. These four profiles are described in Chapter X, along with two utility electricity generation profiles which, though they do not appear very probable, appear the least improbable of the various medium-scale electricity generation scenarios which were studied.

C.4. Effects of Changes in Present Incentive Programs

In order to examine the possible effects of new or modified incentives, a broad listing of sixty-eight possible incentives was prepared (see Appendix D). From this list, the twenty-five considered to be the most important were chosen. The impact of each of these possible incentives on each of the six profiles previously described was then analyzed. Particular attention was given to those incentives which would materially encourage overall resource development and to those incentives which would provide relatively more encouragement to one potential type of developer than to another. The analysis of impacts of different incentives is given in the final chapter, Chapter XI. Overall, this chapter represents the most important part of the study as it presents a reasoned analysis of possible federal incentive programs and the probable impact each would have on the rate and nature of the development of the geopressured-geothermal resource.

CHAPTER II

GEOTHERMAL RESOURCE OVERVIEW

A. OVERVIEW OF GEOTHERMAL ENERGY - THE EARTH'S HEAT

Geothermal energy is rapidly becoming recognized, both in the United States and abroad, as a viable source of energy which can supplement fossil fuels for electric power generation. Exploration and development of geothermal reservoirs is intensifying in the western United States and Mexico, and will continue to expand as petroleum supplies diminish and costs increase. Although geothermal energy is commonly perceived as a new and exotic energy source, it is neither. Steam has been used for electric power generation since 1904 in Larderello, Italy, and geothermal waters have been used for space heating and agricultural purposes in other parts of the world since 1890. Geothermal power generation began in the United States in 1960 at The Geysers, California, and new fields are under development in the Salton trough of southern California.

With nuclear power technology and development lagging behind original time estimates, critical energy shortages appear certain as our needs outstrip our supply of available fuels. As a result of the energy crisis becoming manifest in the United States, an old source of power--geothermal energy--is attracting much attention as a means of alleviating national dependence on fossil fuels.

Geothermal energy represents a "here and now" source of energy. This energy, derived from the heat of the upper 10 km of the earth's crust, represents both an available and virtually nonpolluting power source. Although The Geysers field, with a present power output of 625 mw, is the only geothermal field now in operation in the United States, recent studies have indicated that geothermal resources in this country are widespread. The National Petroleum Council (NPC) has estimated that by 1985 this source of energy could, with rapid development, account for between 19,000 mw and 132,000 mw of power. The latter figure would represent approximately 13.3 percent of estimated energy needs in the United States by that date.

What is geothermal energy? Basically, it is the energy that can be extracted from the natural heat of the Earth. The fact that the Earth is a vast storehouse of heat is evidenced by widespread occurrences of volcanoes, fumaroles, and hot springs. Boreholes drilled into the Earth show progressively higher temperatures with depth. Scientists estimate that temperatures at the center of the Earth lie within the range of 6000°F to 8000°F (3500°C to 4500°C). However, most of this heat is currently beyond the range of our most sophisticated technology. At this time we can only drill for and economically utilize the heat located within about the upper 25,000 feet (7 1/2 km) of the Earth's crust. Although this thin outer shell represents a tiny fraction of the total volume of the Earth, White [1] calculates that more than 3×10^{26} cal of heat is stored in this surficial layer---this is more than 2,000 times the heat stored in all the known coal deposits in the world. The energy supply is so great that it could potentially supply a large percentage of our power needs for centuries to come.

Although the Earth's heat is vast, current technology does not enable us to randomly drill wells in order to obtain sufficient quantities for efficient utilization. Like other sources of fuel, we must locate concentrations of geothermal heat at relatively shallow depths in order to provide an economically feasible supply of power.

Geothermal energy is being exploited in many parts of the world today. In Iceland, individual homes and entire communities are heated with hot geothermal water, while vegetables and flowers are grown in hothouses fueled by geothermal springs. Shallow deposits of hot water are tapped for home heating in Klamath Falls, Oregon, and Boise, Idaho. Using geothermal steam, modest amounts of electricity are being generated in the United States, Italy, Japan, Mexico, New Zealand, and other locales.

Today the technology exists for a much greater use of geothermal energy for power production. New processes under development are likely to lead to significant expansion of this power source. The total potential impact of these developments is estimated as having the ability, ultimately, to meet half of the electric power generating needs of the United States [2].

B. THE GULF COAST GEOPRESSURED-GEOTHERMAL ZONE

In Texas the principal geothermal zones are long, linear, high volume aquifers extending from Laredo to Beaumont. It is presumed, but not yet verified, that a similar reservoir band also runs along the seaward length of the coastline as well. Because of a unique combination of factors involving the accumulation and compaction of great quantities of sands and muds in the Gulf Coast area, hot, overpressured aquifers, usually referred to as geopressured zones, have been created. It has been reported that the geopressured zones along the United States' Gulf Coast Basin are currently among the largest potential sources of natural gas [3].

Geologically speaking, the occurrence of geopressured zones such as are found along the Texas-Louisiana Gulf Coast is uncommon, and this geopressured area is one of the largest zones in the world. Geopressured zones are areas of sedimentary deposits containing trapped water at higher than normal pressures. This trapped water is estimated also to contain significant quantities of dissolved methane. Here, sedimentary deposits exhibit a maximum thickness of some 50,000 feet in some areas, with the upper 25,000 feet primarily composed of alternating series of rock layers which may be broadly classified as sandstones or shales, which are believed to be the origin of the methane in the geopressured formations. However, it is thought that the producing formation of a geopressured aquifer will only be anywhere from 50 feet to 300 feet thick, with a sizable lateral extension. In the Gulf Coast Basin the possibility of hitting a geopressured zone occurs at depths of 5,000 to 15,000 feet, depending upon the age and distribution of sediments.

The resource acquired its present character as a result of geologic events dating back approximately 60 million years. Rivers and streams deposited sediment along the shoreline as they emptied into the Gulf of Mexico. As younger systems deposited their sediment loads over the older units, great quantities of sand sank into the muds of the older delta systems. The penetration of sands into underlying muds resulted in isolation of large sand bodies from the overlying strata. As more and more sediment was deposited, the weight bearing down on earlier deposits increased and they tended to compact. This compaction was accomplished primarily by the expelling of saline water. Frequently, however, the water had no place to go because the surrounding sediments were more or less impermeable to water (having been made that way by pressure and by chemical reactions peculiar to their particular makeups). When this occurred, the water was forced to carry some of the weight of the overburden and began to heat up. As it heated and developed greater internal pressure, the water was better able to absorb methane gas which bled in from the surrounding sediments (shales), which were also under great compaction forces.

The resulting dramatic increase in sediment and fluid pressure often approach lithostatic pressure (one pound per square inch per foot). Thus, fluids contained within these regions will flow naturally into wellbores and to the surface, which gives the possibility that the hydraulic energy may be converted to useful purposes such as the generation of electricity.

C. ECONOMIC AND RESOURCE ESTIMATES

At the present little interest has been shown in the commercial development of the geopressured-geothermal resource for any reason, such as electricity generation, other than for the methane content. And on this subject there is a wide variation of resource estimates, as shown in Table 2-1, which indicates a large degree of uncertainty in the resource assessment by the various groups.

Based on the wide range of recoverable resource estimates, it seems evident that the actual amount of recoverable methane remains unknown for the present. This in turn affects the projected economics of recovering the methane from the geopressured zones. The economic projections would be characterized by uncertainty, and dependent upon numerous factors, including:

- the value of the methane
- the cost of drilling wells suitable for production of fluids at depths of below 15,000 feet
- the ability of the geologic structure to sustain production for a reasonable economic recovery period
- the ability to produce the resource and dispose of waste without significant environmental damages
- the methane saturation of geopressured brine

TABLE 2-1
ESTIMATES OF NATURAL GAS IN GEOPRESSURED AQUIFERS

Date	Name	Total Resource in Place (Tcf)			Recoverable Resource (Tcf)		
		Texas	La	Total	Texas	La	Total
'75	USGS, #726			24,000			2,500
'75	LLL-Howard						222
'76	MOPPS 11						500
'77	Brown (Hudson Institute)			50,000			5,000
'77	Hise (LSU)			3,000			150
'77	Dorfman (UT)			5,700	82		257
'77	Lewin Associates*	184	800	984	4	40	45
'78	Wallace (USGS)		3,200**				
'78	Bernard					14	

*Assumes only in-place and recoverable resource in sands below 300°F. isotherm, and in sands capable of 20+ year production.

**New USGS estimate for South Louisiana and nearby offshore only.

Source: Myron Dorfman. "Evaluation of Natural Gas from Geopressured Zones,"
Gas Supply Review, October, 1978, p.3.

However, if interest continues in the development of the geopressured-geothermal resource a number of detailed steps must be taken to accomplish the task. Figure 2-1 gives an itemized account of the action necessary for commercial development. These utilization tasks may result in either one of the four outcomes shown in the figure, or some combination thereof. These steps are uniform for all outcomes. It is, however, evident that development of the resource by the interested private firm or firms is not currently economically viable because of the many unknown resource parameters. The solution suggested by these interested firms has been to fund extensive research programs in the many uncharted areas of geopressured resource development.

D. GEOPRESSURED RESEARCH PROGRAMS

Several geopressured research programs investigating the nature and dimensions of geopressured-geothermal aquifers along the United States Gulf Coast have been proceeding since 1974 [4, 5, 6, 7]. Funding has been largely provided by the Department of Energy, Division of Geothermal Energy (DOE-DGE), or its predecessor agencies, and various industrial groups in Texas and Louisiana. The studies have centered on obtaining a thorough background of information concerning the extent of the potential resource, fluid characteristics, the technological procedures associated with well design and drilling, reservoir engineering studies, methane extraction techniques, and the institutional, legal, and environmental implications of the resource development. Research has been centered primarily at The University of Texas Center for Energy Studies in Austin and at Louisiana State University, (LSU) in Baton Rouge [8].

E. CONCLUSION

With the rapid depletion of our petroleum reserves, alternative sources of energy are required to alleviate dependence on foreign fuel. Geothermal energy represents a viable energy source which, with rapid development, may partially fulfill our energy requirements. Present technology is sufficiently advanced to explore for, drill, and produce geothermal wells. There are however, other barriers to resource development which must be addressed first.

Figure 2-1: UTILIZATION TASKS

CHAPTER III

EVOLUTION OF THE CURRENT TEXAS*

GEOPRESSURED-GEOTHERMAL INSTITUTIONAL STRUCTURE

A. EARLY INVESTIGATIONS

The modern history of interest in the geopressured zone along the Texas-Louisiana Gulf Coast probably begins in the late 1960's with the work of US Geological Survey (USGS) hydrologists Paul Jones and Ray Wallace. Their work, of course, built on earlier work, such as that of Clarence Hottman at Shell Oil in the mid-1960's and of others dating back to at least George Dickinson in 1953. However, the USGS study, because of its continuous and geographically broad-ranging nature, marks a fair starting point for modern investigation of the resource. The results of this study first received general recognition among geologists and petroleum engineers at Louisiana State University's First Symposium on Abnormal Subsurface Pressure in 1967.

It was at about the time of the LSU conference that Dr. Ralph Kehle, then with The University of Texas Department of Geological Science and a consultant for the Bureau of Economic Geology (BEG), was appointed to an American Association of Petroleum Geologists committee which was to oversee a geothermal gradient mapping project. Paul Jones was also on this committee. The project was nationwide, but Dr. Kehle assumed responsibility for that portion of the project which focused on the Texas Gulf Coast. The general procedure which he used to compile his geothermal gradient map for the Gulf Coast region was to have graduate students examine the well logs from the three deepest wells in each county and from these logs select a representative well. Then, thermal characteristics were determined for that well from the well log.

While working on this project, Dr. Kehle consulted with other committee members, especially Jones, Wallace, and their colleagues at the USGS. USGS studies from the early 1940's of hydro pressured fresh-water reservoirs were re-examined because natural gas wells completed in the geopressured zone were also found to occasionally produce fresh water. The current belief is that this latter fresh water is condensed vapor from brines with which natural gas is often associated and that the real potential for recovering large volumes of fresh water from the geopressured zone is very low. The fresh water possibility, however, served to further interest in the geopressured resource.

In 1972, the Petroleum Extension Service at The University of Texas at Austin asked Myron Dorfman, then a petroleum engineering graduate student at UT, to prepare a publication on geothermal drilling and production techniques. The Petroleum Extension Service provides continuing education to individuals in the oil and gas industry and these individuals were frequently encountering the problems of geothermal temperatures as the western states' geothermal resources and deep Gulf Coast hydrocarbon resources were explored.

A short time later, while Kehle's work was still ongoing, Dr. William Fisher, Director of the Bureau of Economic Geology, decided that the BEG should prepare an overview publication on geothermal resources in Texas. The BEG is the state equivalent of the US Geological Survey. In the course of conducting other studies over a period of years the BEG had accumulated a good deal of heat gradient information in addition to that which was being accumulated by Dr. Kehle. Dr. Fisher interested Myron Dorfman in the overview publication and charged him with its preparation; Dr. Kehle also participated on this project in a review capacity. (Gene Herrin of Southern Methodist University began a similar project with Air Force funding at about this time, also.)

*This history focuses on geopressured-geothermal activities along the Texas Gulf Coast. Although events which transpire in Louisiana often have a direct impact on the Texas resource, this history does not in general document those events in as much depth as events which occurred in Texas.

As one should infer from the previous paragraphs, Myron Dorfman had more standing in the fields of petroleum and geology than do graduate students generally. This is because he had spent some twenty years as an independent oil and gas producer in Shreveport before returning to The University of Texas in 1971 to do graduate work (first toward an M.S. and, then, a Ph.D. in Petroleum Engineering). He was therefore known by individuals active in the oil and gas industry and had a great deal of practical experience within the industry.

During the first half of 1973, the Petroleum Extension Service publication on geothermal drilling and production techniques appeared. Also during this time, Myron Dorfman made a presentation on the geopressured zone for the American Association of Petroleum Geologists and attended a geothermal energy conference held in California. At this latter conference, a speaker affiliated with Lawrence Livermore Laboratories (LLL) of the University of California at Berkeley made a presentation on the Gulf Coast geopressured zone; because Dorfman thought this presentation was in many respects incomplete or inaccurate, he convinced the speaker to return with him to Texas so that he could explain more fully the work then ongoing at the BEG. This contact ultimately proved to be quite important, because it was through LLL that The University of Texas-BEG program to study the geopressured zone first received federal funding.

In the fall of 1973, the public took official notice that there existed an "energy crisis." The Texas House of Representatives' Energy Study Committee, chaired by Representative Jon Newton, conducted public hearings on energy problems likely to face the state during the 1970's. In the course of these hearings, the potential of the geopressured-geothermal resource received a good deal of publicity. Media coverage of the hearings spread this publicity and began to stir the interest of the state's industrial leaders.

B. ACADEMIC RESEARCH BEGINS

In part because of the energy debates which emerged in the fall of 1973, Dr. Stephen Spurr, then president of The University of Texas at Austin, established in January, 1974, at the university, the Center for Energy Studies. The center was to serve as the focal point for university activities relative to certain aspects of energy use and their concomitant impacts on the environment and social structure of the region. Further, the center was to be a coordinating organization through which university faculty and research personnel could receive some of the federal, state, and private funds which were expected soon to flow more freely into energy research. During February of 1974, personnel from the BEG briefed personnel of the newly-formed CES on the Gulf Coast's geopressured resources.

In June, Lawrence Livermore Laboratories gave the BEG a relatively small (\$26,000), but quite important, first grant to begin an assessment of the geopressured resource. LLL was at that time a distribution point for funds originating in the Atomic Energy Commission (AEC) (which, in this respect, was one of the predecessors to the Department of Energy). The Center for Energy Studies augmented this grant with funds (\$12,000) it had received from The University of Texas.

Dr. Don Bebout, who had extensive practical experience previously as a geologist working with Exxon, directed the BEG's resource assessment effort. The first effort focused on the southwestern end of the band in which the geopressured zones were known to exist; this area, known as the Rio Grande embayment, had been an area of focus for the previously-mentioned work of Herrin and of Jones and Wallace. Bob Swanson of the Southwest Research Institute (SWRI) also examined this area for the Energy Research and Development Administration (ERDA). Subsurface temperatures were thought to be higher at more shallow depth here than further up the coastline. The research methodology, which the BEG also employed as it moved to the middle and northeastern sections of the band, called for work in two phases. First, professional geologists and geology graduate students collected well logs for wells throughout the section of the band being studied; from these it was possible to determine particular areas within the band which merited more intense, site-specific, study. More logs could be gathered for the site-specific studies and these logs could be analyzed in more detail.

Throughout the course of this south Texas assessment (and during subsequent assessments, as well), BEG and other UT personnel enjoyed full cooperation from oil and gas producers. These producers have proprietary interests in their well logs and could properly have withheld them from the research teams. Their cooperation arose

largely because of producer faith in the competence and impartiality of those active in the research effort. Too, oil and gas producers favor university research of this nature because it provides practical experience for students who will, in all likelihood, ultimately work in the oil and gas industry.

In September, Dr. Gary Underhill, a professor at The University of Texas, organized and conducted a geopressured-geothermal energy workshop in Austin. Dr. Underhill's effort was sponsored by the CES, with partial financial support from the National Science Foundation (NSF). This workshop dealt with electrical generation from geothermal resources, but was principally concerned with process heat applications. It was one of the first organized efforts by academicians to involve industry personnel in technical and market discussions about the resource.

Also in the fall of 1974, Mr. Fred Repper, then a Vice-President of Central Power and Light Company, contacted Dr. Herbert Woodson, Chairman of the Department of Electrical Engineering at The University of Texas at Austin and also Director of the Center for Energy Studies. Central Power and Light serves the south central Texas coastal zone and, in common with other Texas utilities, had developed an interest in the possibility of generating electrical power from the energy in the geopressured-geothermal reservoirs. There was precedent for generating electricity from hydrothermal geothermal resources in California. The enthusiasm for similar possibilities in Texas had been on the upswing during the past year as media and coastal community leaders became better informed about the geopressured-geothermal resources.

C. FIRST INDUSTRIAL FUNDING

Dr. Woodson referred Mr. Repper to Myron Dorfman, who was directing the geothermal effort for the Center for Energy Studies. Mr. Repper indicated that Central Power and Light, and perhaps other Texas utilities, would be interested in contributing research funds to the CES effort. Later in the fall of 1974, Central Power and Light did commit funds to support the CES effort, as did Texas Utilities Services, Inc. (\$150,000 each). These two commitments were significant in themselves and were very timely because they demonstrated commercial interest in the resource and thereby bolstered relatively large research proposals which personnel at The University of Texas were preparing to submit to the National Science Foundation.

The proposals to NSF requested funding of about three-quarters of a million dollars and were the first attempts to get really significant federal support for the geopressured-geothermal research program. The proposals were developed under the umbrella of the Center for Energy Studies, with various research tasks to be conducted by personnel affiliated with the Bureau of Economic Geology, the UT Petroleum Engineering Department, and the UT Mechanical Engineering Department, as well as personnel affiliated only with the Center for Energy Studies. The proposals called for a multidisciplinary research effort to investigate both technical and nontechnical aspects of geopressured-geothermal resource development. The four principal areas of study were to be: geological resource assessment; resource production research; surface utilization techniques; and legal, institutional, and environmental ramifications of resource development.

Early in 1975, while the NSF proposals were still pending, the Energy Research and Development Administration (the successor of the AEC) provided additional short-term funding (\$40,000) to continue resource assessment efforts along the middle Texas Gulf Coast. Also during this period, CES personnel began planning the First Geopressured-Geothermal Energy Conference which was to be held at The University of Texas campus in Austin in June of 1975. ERDA provided funding (\$15,500) for this conference.

In March of 1975, Gulf States Utilities Company committed \$75,000 to support the UT research program. At this time, they also committed money to the research effort being conducted by LSU in Louisiana; parts of Louisiana are in the Gulf States service area. (Also in Louisiana, Middle South Services Company, an electric utility holding company, was providing LSU's Bill Hise support for geopressured-geothermal research.)

The Texas Legislature acted in the spring of 1975 on recommendations which had been developed in the fall of 1973 and throughout 1974 by passing the Geothermal Resources Act. Max Sherman, in the Senate, and Jon Newton, in the House, were particularly interested and instrumental in getting this legislation passed. The crux of the legislation was that it vested jurisdiction in the Texas Railroad Commission to regulate geopressured-geothermal development on public and private lands in Texas; the General Land Office shares some of this jurisdiction where development affects state-owned lands.

D. SIGNIFICANT FEDERAL FUNDING

Finally during May, ERDA funded the proposals initially developed in late 1974 for submission to the National Science Foundation; \$495,000 was approved for resource assessment and approximately half again that amount was approved for scope-of-work ("Phase 0") studies in the other research areas.

Also in May, Dr. Fisher took a leave of absence from the BEG to serve as Deputy Assistant Secretary and, later, Assistant Secretary of Energy and Minerals with the US Department of Interior in Washington. In his absence, Dr. C. G. Groat became the acting Director. Dr. Groat was already active in the resource assessment program with Dr. Debout, so this important personnel change caused no transition problem at the bureau.

The geopressured-geothermal research program began moving forward on a rather broad front at this time and enjoyed the support of state and federal government as well as private industry. To ensure that all supporters remained informed of developments in the research effort and to further ensure that academicians conducting the research effort remained in touch with the various supporting groups, a Board of Advisors for the geopressured-geothermal research project was created in May of 1975. The fourteen member board, which has since been enlarged, initially consisted of the representatives from the following organizations:

Brown and Root, Inc.	Louisiana Department of Conservation
Railroad Commission of Texas	Texas Utilities Services, Inc.
Texas Air Control Board	Texas Water Rights Commission
General Land Office	Exxon Production Research Company
Texas Water Quality Board	Texas Water Development Board
Gulf States Utilities	Mobil Research and Development Corporation
Central Power and Light	Electric Power Research Institute

The board met for the first time on June 3, 1975, following a plenary session of the First Geopressured-Geothermal Energy Conference.

E. FIRST GEOPRESSURED-GEOTHERMAL ENERGY CONFERENCE

The first conference not only provided a forum at which to present the results of UT studies which were of interest to individuals and organizations working on various aspects of geopressured-geothermal energy, but also, it provided an opportunity for groups outside The University of Texas to make their activities in the geopressured-geothermal research program known. Representatives from organizations such as Dresser Industries, Dow Chemical, and Magma Power Company made presentations, as did scientists from Lawrence Livermore Laboratories. Paul Jones had joined the Louisiana State University faculty by this time and led a contingent of authorities on the Louisiana resource. The conference was organized in four major sessions, which reflected the broad-ranging nature of the research effort underway; separate sessions were devoted to resource assessment, reservoir research and technology, surface utilization technology, and legal and environmental ramifications of resource utilization.

The month of the conference also saw increased intensity in ERDA-funded research at The University of Texas. A number of contacts were made with oil and gas firms to determine how best to model critical parameters, such as well-bore heat flow, and how best to digitize well-log data for entry in and retrieval from a computer-storage data base. Too, Dow Chemical and Brown and Root began their subcontract work (for CES) to design power plants for utilization of the heat energy of geopressured-geothermal brines; Dow had earlier submitted and, later, withdrawn a proposal to AEC that it conduct this work for AEC directly. (Dow's contract called for it to focus on power generation by the "flash" steam method. This method envisions that the geothermal brine will be flashed by pressure reduction to steam and that steam used to drive turbines which generate electricity. Brown and Root's contract called for it to work on power generation by use of the binary cycle method. This method envisions use of a secondary fluid which will be vaporized on contact with a heat exchanger through which the geothermal brines flow; the vaporized secondary fluid then drives turbines which generate electricity). Dr. K. E. Starling of the University of Oklahoma began a study which was auxiliary to the Brown and Root work and which dealt with optimum secondary working fluids.

During July and August, Myron Dorfman met with representatives from the Texas Railroad Commission to help develop administrative regulations to control geopressured-geothermal well drilling and development. Drs. Richard Deller, Assistant Director of the geothermal program at the Center for Energy Studies, and Gary Underhill visited with a number of Gulf Coast firms which might potentially use the geopressured brine for process heating purposes. They also prepared a draft study which envisioned the use of the geopressured brine for Frasch sulphur mining and secondary oil and gas recovery.

For the remainder of the year, research personnel devoted most of their efforts to two tasks: (1) the Phase 0 work on legal and institutional parameters and (2) the collection of hard data on the methods and costs of drilling a geopressured-geothermal well. To this latter end, contacts were made with seismic mapping firms (such as Teledyne Exploration), well casing suppliers (Lone Star Steel), mud and well monitoring firms (Baroid), cementing and completion firms (Halliburton), and firms which specialize in well logging and sampling (Schlumberger). The legal work was contracted to Don Elmer, now with DGE's Hydrothermal Support Branch but, then, a private consultant. Mr. Elmer's work laid the analytical ground work on which most subsequent legal work regarding the resource has built.

The USGS released its first assessment of geothermal resources nation-wide in the fall of 1975. This assessment, Circular 726, dealt primarily with western-state geothermal resources, but also examined the on-shore Texas and Louisiana geopressured resource. The USGS estimated that the on-shore geopressured resource might contain 67,456 quadrillion BTU's of energy, of which 2 or 3 percent might be recommendable. By way of comparison, the US currently consumes about 80 quadrillion BTU's per year.

During the winter of 1975, Myron Dorfman made a detailed presentation of the research activity ongoing at The University of Texas to representatives of United Gas Pipe Line Company; this ultimately led to financial support of the research activities by United Gas. ERDA granted a four-month, \$51,000 extension of its initial Phase 0 grant and the LBJ School of Public Affairs began a government policy alternatives project which focused on geopressured-geothermal energy.

F. SECOND GEOPRESSURED-GEOTHERMAL ENERGY CONFERENCE

In February, 1976, the Center for Energy Studies sponsored the Second Geopressured-Geothermal Energy Conference at The University of Texas at Austin. The second conference covered in greater depth the four subject areas covered at the first conference and, in addition, dealt with sociological implications of geopressured-geothermal development. The five-volume proceedings of this conference set out the results of the ERDA and industry-funded Phase 0 studies coordinated by Dr. Dorfman through the Center for Energy Studies.

February also marked the beginning of ERDA funding (\$175,000) of what has become a large project to develop a reliable mathematical description of a geopressured reservoir; Dr. Roy Knapp of the UT Petroleum Engineering Department directed the project through 1978, with extensions, at which time Dr. Robert MacDonald assumed this responsibility. Systems, Science and Software of La Jolla, California, has been responsible for much of this work on a subcontract basis.

During the early spring, the Center for Energy Studies and the Governor's Energy Advisory Council co-hosted a legal-institutional problems symposium at which representatives from the Texas and Louisiana research and governmental communities discussed coordination of their activities relevant to geopressured-geothermal development.

In April, United Gas Pipe Line Company became the fourth industrial concern to contribute financial support (\$99,000) to the research activities at The University of Texas. Unlike the other three contractors, United's primary interest in the resource was not for electric power generation but, rather, as a source of natural gas; United had been one of the first of the major interstate pipeline companies to curtail gas deliveries to industrial customers in the early 1970's because of gas supply shortages and had a heightened interest in unconventional sources of natural gas.

G. MORE ATTENTION TO INSTITUTIONAL BARRIERS

The early summer of 1976 brought about two important legal-institutional developments. First, in May, A. W. Oberbeck became affiliated with the Center for Energy Studies and began a project to examine in depth the legal, regulatory, and resource ownership questions which might present institutional barriers to geopressured-geothermal development in the future. This led to the publication in early 1977 of two papers, extensively co-ordinated with responsible state agency personnel, which addressed ownership issues and regulatory controls over water pollution.

In June, Dr. Dorfman was successful in convincing the Interstate Oil Compact Commission (IOCC) to establish a geopressured-geothermal section to monitor and analyze legal problems incident to geopressured-geothermal development.

For several months prior to July, 1976, the CES and ERDA had been negotiating a proposal under which the CES was to direct a number of geopressured research projects and was to coordinate for ERDA various research activities being conducted at the Bureau of Economic Geology and within various departments at The University of Texas. This "coordination" proposal was approved (for \$203,000) in July and has, since that time, provided the organizational framework within which a number of geopressured-geothermal research projects have been conducted. Also during July, Dr. Dorfman made a presentation at a United Nations-sponsored conference in Vienna; this conference gave international exposure for the research effort ongoing along the Texas Gulf Coast. Scientists and energy officials from other countries, notably the USSR, where similar resources are thought to exist, also attended the conference.

In line with the broad scope of research activities being coordinated through the Center for Energy Studies, Drs. Sally Lopreato and Marlan Blissett, affiliated with the Center for Energy Studies and the LBJ School of Public Affairs respectively, began in September to conduct an attitudinal survey (\$28,000) of citizens living in the area where it was anticipated the first geopressured-geothermal well would be drilled. W. E. Boyd, previously the Director of the Petroleum Extension Service of The University of Texas and a man with some thirty years' practical oil and gas experience working with Gulf Oil Company, was hired by the Center for Energy Studies to help develop a well drilling and completion program. Also this month, Dr. Tom Gustavson of the Bureau of Economic Geology received a grant (\$48,000) from the US Fish and Wildlife Agency to conduct ecological studies along the Texas-Louisiana Gulf Coast. These ecological studies were coordinated with the UT Marine Science Institute at Port Aransas.

H. INCREASED EMPHASIS ON METHANE CONTENT

The October issue of Fortune Magazine carried a two-page summary by W. M. Brown of a geopressured methane report he and others had prepared at the Hudson Institute. Though the report was based on physical assumptions many researchers considered to be unsound, its summary caused quite a stir among the business and political leaders who read Fortune because it speculated that upwards of 2,500 Tcf of natural gas could actually be recovered from on-shore geopressured reservoirs alone. At that time (as now), US natural gas consumption was only about 20 Tcf of methane yearly.

During October and November of 1976, research personnel at The University of Texas made a number of contacts with regulatory agencies and professional research organizations concerning the geopressured-geothermal research program at UT. The Texas Air Control Board and the Texas Water Quality Board were given in-depth briefings, as were guest attendees, notably from the Institute of Gas Technology and the Gulf University Research Consortium, at the November meeting of the Geothermal Board of Advisors.

At approximately this time, an informal examination of geopressured-geothermal research projects was being concluded at the Institute of Gas Technology (IGT). IGT is an educational and research organization affiliated with the Illinois Institute of Technology and, as the name suggests, is primarily interested in gas production technology. IGT's examination suggested that there were areas related specifically to gas production from geopressured reservoirs where they could profitably conduct detailed technical projects. In light of this, they subsequently sought and secured (in December) funds from ten natural gas companies with which to design and construct a surface laboratory facility capable of producing, for test purposes, the environment of a geopressured-geothermal reservoir.

In January of 1977, Dr. Dale Zinn, who later directed a geopressured-geothermal operations research project at the Center for Energy Studies and, later still, succeeded Richard Deller as the Assistant Director of the CES's entire geothermal program, met with Dr. Bert Wilkins, Director of Research at Louisiana State University. This was one in an ongoing series of meetings held between research and government personnel of the two states in an effort to coordinate activities within the states and avoid duplication of research.

February saw the return to the BEG of Dr. William Fisher. Dr. Groat, who had been Acting Director in Dr. Fisher's absence, joined the faculty at The University of Texas at El Paso at this time and began direction of a research project there to examine West Texas geothermal resources other than geopressured-geothermal.

I. ESCALATING FEDERAL SUPPORT: TEST WELL PROGRAM

Also in February began eight months of negotiation between ERDA and General Crude Oil, Inc. (GCO), concerning the drilling of the first geopressured-geothermal well along the Gulf Coast. One of the optimum sites developed by Dr. Bebout in his resource assessment effort was located beneath land to which General Crude held both the surface and mineral rights. This was a fortunate circumstance in light of the unresolved legal issues regarding resource ownership in cases where these rights have been severed. General Crude was the obvious contractor to direct drilling of the first well. In March, the American Gas Association (AGA) Gas Supply Review carried a condensation of Dr. Dorfman's presentation to the AGA's Marketing Conference. Although this was only one of many similar geopressured methane articles in the literature at the time, it was significant because it popularized geopressured methane potential before the non-research gas audience which is expected to bear most of the ultimate cost of commercialization of the resource.

During the spring of 1977, Dr. Dorfman also made formal presentations to the U.S. House Subcommittee on Science and Technology and a conference at the Lawrence Livermore Laboratory in California. It was also a particularly good season for research funding. Dr. Knapp received extension funding from ERDA to continue his work on reservoir simulation modeling. Dr. Gustavson received ERDA funding to conduct several site-specific environmental impact studies, and Dr. Zinn received ERDA funding for the first formal geopressured-geothermal operations research work to be conducted at the CES. Dr. Bebout received a funding extension on his resource assessment work, and Drs. Gray and Thompson (CES) received their initial ERDA grant to study rock mechanics of geopressured formations. In all, government support grew by \$838,000. Also of major significance during this period, Houston Lighting and Power Company became the fourth electric utility to contribute significant financial support (\$150,000) to the geopressured-geothermal activities being conducted at The University of Texas.

While negotiations were still underway between ERDA and General Crude concerning drilling of the first geopressured-geothermal well along the Gulf Coast, testing was being completed at an old well which had been re-entered along Tigre Lagoon in Louisiana. It had been hoped that re-entry of a previously sealed well for the purpose of testing in the geopressured zone would provide a cheap and expedient method of gathering fluid samples and reservoir flow information. The results of this re-entry and testing program proved to be somewhat ambiguous and rather expensive. This turn of events further complicated negotiations between ERDA and General Crude for drilling of the Brazoria County well.

Also, during July, Dr. Bebout received \$100,000 from ERDA for sand-stone consolidation analysis. The coordination project directed by Dr. Dorfman received funding (\$136,000) for a three-month extension period; this was followed by a \$553,000 eleven-month renewal in November.

In the late summer of 1977, Dr. Bebout's resource assessment effort began to focus more and more seriously on the Vicksburg and Wilcox formations. These lie inland from the Frio formation on which the first resource assessment efforts focused and in which is located the Brazoria County well site. Finally, in October, the Department of Energy, as the governmental successor to ERDA, and General Crude signed a contract under which General Crude was to direct drilling of a geopressured-geothermal test well on the General Crude property in Brazoria County. Transco Energy Company of Houston and Shell Oil Company both agreed to waive, for the purposes of this test well, their rights to patents and processes for the extraction and utilization of geopressured brine and methane.

DOE also signed at this time a contract with Gruy Federal, Inc., under which Gruy was to re-enter, complete, and flow test geopressed "wells of opportunity" in Texas and Louisiana. A well of opportunity, in this instance, is a conventional oil or gas well which passes through or overlies a geopressed aquifer and has been or will soon be abandoned without having produced oil or gas. To date, Gruy has been unable to obtain an appropriate well in Texas and has successfully tested only one, the Fairfax Foster Sutter #1, in Louisiana.

Gulf Universities Research Consortium (GURC), a Houston-based research group affiliated with some eighteen universities and approximately that many industries along the Gulf Coast, completed, at about this time, a study of the geopressed resource for DOE's Division of Oil, Gas, Shale and In Situ Technology. The GURC study dealt with the potential for electric power generation, but focused primarily on the potential for gas recovery from the geopressed reservoirs.

The Third Geopressed-Geothermal Energy Conference was held in Lafayette, Louisiana, in November, 1977. This conference, held at the University of Southwestern Louisiana (USL) and directed by USL's John Meriwether, was called primarily to discuss results from the re-entered Tigre Lagoon well. November also brought Dr. Gustavson of BEG a \$30,000 grant from LLL to examine generic impacts of geopressed-geothermal development; DOE extended his site-specific environmental monitoring project through December, at which time a \$250,000 one-year extension became effective.

J. PARTIES OUTSIDE THE UNIVERSITY ARE ACTIVE

Bob Armstrong, Commissioner of the General Land Office of Texas (GLO), had made a presentation at the First Geopressed-Geothermal Conference held in Austin in 1975. He had, since that time, maintained an interest in the research programs ongoing at The University of Texas. In December, 1977, he requested a thorough briefing on those projects so that he could better determine what regulatory research activities the General Land Office, which has certain responsibilities over all state-owned lands, should undertake regarding geopressed-geothermal resources. Personnel from CES and the BEG presented Commissioner Armstrong with a briefing in December, and the Land Office did subsequently apply for and receive DOE funds with which to develop appropriate regulations.

In January and February of 1978, several developments arose which had an impact on state law and policy relevant to geopressed-geothermal energy development. First, then-Governor Dolph Briscoe appointed Mack Wallace, Chairman of the Texas Railroad Commission, to act as the Governor's representative to the federal government for matters concerning geopressed-geothermal energy development. Chairman Wallace appointed an ad hoc committee to formulate suggestions for state statutory modifications which the Governor's office might propose in the upcoming session of the Texas legislature. He also met with high ranking executives from the Department of Energy and Bill Huls, Director of Louisiana's Department of Natural Resources, in an effort to coordinate geopressed-geothermal research and legislative activities among Texas, Louisiana, and the federal government.

At the end of February, Kaiser Aluminum and Chemical Corporation released a formal preliminary report on its in-house study of the energy potential of the geopressed resource. The report did not make recommendations regarding Kaiser's commercial exploitation of the resource, but did attempt to quantify in a general fashion economic parameters on which recommendations could be based. The report is thought to be representative of others, such as those of J.S. Wilson and his colleagues at Dow Chemical, which reflect real, but thus far very cautious, industry interest in the resource.

Later in the spring, Dr. Dale Zinn received a seventeen-month grant (\$50,000) from the Texas Energy Advisory Council to fund continued geopressed-geothermal operations research efforts at the Center for Energy Studies. This represented the first state grant money which had been put into any of the geopressed-geothermal research activities. At about this time, DOE made its award to the General Land Office; Research and Planning Consultants, Inc., which had extensive knowledge of the Texas coastal zone, contracted with the GLO to develop policy outlines within which the GLO should ultimately structure its geopressed-geothermal regulations.

The American Gas Association sponsored a symposium on geopressed methane in June which attracted a number of federal, financial, and industrial participants. The symposium served to keep influential sectors of the governmental and business communities abreast of the potential for geopressed methane development.

During the spring and early summer of 1978, several new programs began at The University of Texas. Dr. Bebout had primary responsibility for one of these, a \$342,000 examination of the volume and accessibility of the methane believed to be entrained in the deep geopressured reservoirs along the Gulf Coast. This was funded by DOE's Division of Oil, Gas, Shale, and In Situ Technology. Dr. John Vanston of the Center for Energy Studies had primary responsibility for another, an \$85,000 examination of the various possible institutional structures through which the resource might ultimately be utilized and an analysis of government incentives which might put those structures in place. A. R. Gregory of the BEG also received DOE funding (\$102,000) to conduct a study of the effects of high pressure (geopressure) on rock elastic properties. Dr. Bebout turned to consideration of specific well sites within the Wilcox and Vicksburg formations during this period and Dr. Knapp's computer reservoir simulation work received a \$202,500 extension. During June, Houston Lighting and Power, Gulf States Utilities, and Central and Southwest Corporation each contributed an additional \$25,000 to fund conceptual power plant design work at UT. Dr. Parker Lamb of the Mechanical Engineering Department heads this effort, which builds on the previously described work of Dow Chemical and Brown and Root.

K. TEST WELL DEDICATION

On July 7, dedication ceremonies were held along Chocolate Bayou in Brazoria County, Texas, as drilling operations began on the GCO-DOE Pleasant Bayou #1 well, the world's first exclusively geopressured-geothermal well. (The well was actually spudded on June 30). The drilling plan for this well contemplated an October 1st completion at a depth of approximately 16,500 feet. The drilling plan also contemplated extensive testing and sampling operations through which data would be gathered at all depths to assist the research program underway through the BEG at UT.

During the summer and fall, drilling operations continued on the Brazoria County well; a number of factors, mostly related to drilling in high pressured regimes, slowed progress on the well so that completion in late winter, 1978, became the target. Also during this period, Dr. Zinn received DOE funding (\$155,000) to expand his operations research project and plans got underway for the Fourth Gulf Coast Geopressured-Geothermal Energy Conference. The CES would sponsor this conference in Austin after the Brazoria County well was completed and at least preliminary tests had been run. In October, IGT received two-year DOE funding to do more work on computer simulation of production from geopressured reservoirs. Values for reservoir parameters for the simulation model were and are to be derived from the results of IGT's industry-funded lab work, the Tigre Lagoon well, the Brazoria County well, and other geopressured drilling programs as they unfold.

On October 15, 1978, the Congress passed and sent to the President for his signature a packet of five bills which are collectively known as Phase One of the National Energy Plan (NEP 1). Parts of NEP 1 may be important to geopressured-geothermal development, depending on the course that development takes. NEP 1 calls for the decontrol of the price of natural gas from geopressured wells by the end of 1979; incremental pricing would be applied to this gas, but under a relatively tolerant standard. Many electric power generation facilities are required to cease using gas or oil by 1990; however, the Economic Regulatory Administration has defined "natural gas" in such a way that geopressured methane is excluded and, hence, may still be used as boiler fuel. Tax deductions for abandoned gas or oil-fired boilers probably encourage geothermal development slightly and discourage geopressured methane development slightly. Federal income tax credits for investment in equipment to produce or utilize geopressured brine are made available, though on a rather short-term basis. A similar credit may also be taken for investment in equipment used to produce natural gas from geopressured brine. Finally, NEP 1 allows a producer of geopressured natural gas or (apparently) brine a percentage depletion deduction and current deduction of intangible drilling costs.

At about this time, DOE opened its long-contemplated Division of Geothermal Energy field office in Houston. As expected, Keith Westhusing was selected to head this office. Both the opening of the office and the selection of Mr. Westhusing were generally applauded as an indication that DOE would retain a significant and pragmatic commitment to its geopressured-geothermal program.

The November National Geographic Magazine carried an article on unconventional sources of natural gas supply which dealt at length with geopressured methane. This very positive treatment was, on the one hand, welcomed by researchers because it was

felt to promote support for their efforts among the general public. On the other hand, researchers saw that the article, like the Hudson Institute study, could ultimately impair their efforts by raising public expectations to heights which the resource and technology for its utilization do not appear to justify.

During November and December, two CES research teams held meetings with industry groups interested in geopressured development. The first of these was a one day briefing and discussion sponsored by Dr. Zinn as part of his operations research work; industry participants at this meeting were primarily from the gas and electric utilities. The second meeting was actually a set of four separate "round table" discussions, each attended by separate industry sectors (thus, energy producers and financiers attended one, electric utilities and architectural engineering firms another, gas utilities another, and large energy consumers the fourth). These discussions were sponsored by Dr. Vanston's institutional structures study and focused on incentives which might be particularly appealing to industries in the various sectors. Randall Stephens, of DOE and the Interagency Geothermal Coordinating Council, participated in the latter discussions and conveyed ideas developed during those discussions to policy makers in Washington.

December brought financial support (\$12,500) for the UT project from Central and Southwest Corporation, the holding company for a number of electric utilities (among them Central Power and Light) and DOE renewed the coordination contract for a year at \$681,000. Dr. Gustavson's environmental monitoring work was also extended another year and \$250,000. The Gas Research Institute (GRI) announced that it would fund work by the BEG for 18 months and \$324,700 to identify favorable sites for test wells to penetrate shallow geopressured zones. These zones would not be expected to produce brines at temperatures high enough to support electricity generation.

Also, the Electric Power Research Institute (EPRI) awarded a research contract to Southwest Research Institute (SWRI) of San Antonio, Texas, for an assessment of the feasibility of developing geopressured-geothermal resources for the generation of electrical power on a commercial scale. R.K. Swanson was to lead the research effort for SWRI, with Bechtel and Intercomp as subcontractors for the one year program.

Of a much less positive nature, severe problems with the Brazoria County well eventually led to its abandonment as a production well on New Year's Eve. The ultimately fatal problem was that the walls of the well began to collapse around the drill pipe in the 10,000 foot zone. Attempts to alleviate this problem caused its spread to higher levels, and the decision was made to convert the well from production to disposal functions by sealing it with a cement plug somewhat below 8,000 feet. The drilling rig was moved approximately 500 feet from the now-disposal well site, and production well drilling operations on Pleasant Bayou #2 began in January, 1979.

In February, the U.S. Geological Survey Circular 790 was published. Entitled, Assessment of Geothermal Resources of the U.S. - 1978, edited by L.J.P. Muffler, this comprehensive publication was a refinement and update of information, Circular 726, the USGS had previously published in 1975. Non-proprietary information available in June 1978 was used to assess geothermal energy in the ground, and when possible, to evaluate the fraction that might be recovered at the surface.

A review of DGE's geopressured-geothermal program was held in Houston in March. CK GeoEnergy sponsored the two day program, in which some sixty individuals representing government and industry participated. March was also the beginning of the BEG's \$49,005 preliminary environmental analysis of the Wilcox formation geopressured-geothermal prospect areas in Texas. Tom Gustavson and his research group were to compile baseline environmental data in DeWitt and Colorado counties.

The Test Well Program received a boost in April when it was announced that Gruy Federal had received the go-ahead from DOE to test the Neuoff oil and gas corporation's #2 Fairfax Foster Sutter well in Louisiana. This well was to be entered under the well of opportunity program. This entry and testing attempt proved to be successful, though the results were not very encouraging. Total dissolved solids were almost 20,000 mg/liter, methane content was only 22.5 scf/bbl, bottom hole temperatures were about 270 F, and scaling problems were significant.

May saw new legal initiatives affect the geopressured-geothermal resource. The Texas State House Bill 1490 was signed by Governor Bill Clements on May 15th. It became effective August 27, 1979, and amended the Natural Resources Code and Water Code, as recommended by legal researchers at The University of Texas at Austin,

to clarify the "mineral" nature of the resource and the Railroad Commission's jurisdiction over it. The Economic Regulatory Administration (ERA) issued on May 17th an interim ruling to implement provisions of the Power Plant and Industrial Fuel Use Act of 1978. This ruling provided that geopressured methane from wells spudded prior to January 1, 1990, may be burned as boiler fuel in instances where the act otherwise prohibits natural gas-fired boilers.

Drs. Debout, Dorfman, Loucks, and Zinn attended a June meeting in Vienna, Austria, under the auspices of the International Institute for Applied Systems Analysis. The US delegation met with representatives from the National Academy of Sciences of the USSR to discuss the geology of geopressured basins in their respective countries. On June 2nd, Pleasant Bayou #2 reached final depth of 16,500 feet and efforts to test the well were begun. Also, in June, Governor Clements renamed Myron Dorfman to the Geothermal Resources Committee of the Interstate Oil Compact Commission for 1979-80 and Acting Assistant Director of the UT program, Lewis Jones, made a presentation on UT's projects at EPRI's June 24th meeting in Monterey, California.

CHAPTER IV

PROJECT EVALUATION WITH UNCERTAINTY AND THE STRUCTURE OF INCENTIVES

A. INTRODUCTION

This chapter develops the concept of project uncertainty and its effect upon the level of investment by private enterprise in a large-scale energy project. It outlines the types of risks which are prevalent in a reservoir development project, including geophysical risks, market risks, financial risks, regulatory risks, and catastrophic risks, and explains how firms typically evaluate projects which include these risks. Methods of sharing and segmenting project uncertainty developed within the private sector and based upon different levels of aversion to specific risks by project participants, are explored. Finally, a conceptual framework within which the government might evaluate its incentive programs and target incentives to reduce critical uncertainties is developed.

B. GOVERNMENT INCENTIVES AND PROJECT PRESENT VALUE

In the mixed-capitalist economy which has dominated the United States following the second World War, incentives have been widely used by all levels of government to stimulate private investment. These incentives are usually designed to encourage overall business investment for countercyclical economic stimulus, to raise investment and employment in certain regions, or to stimulate investment in particular industries to effect technological modernization or to increase that industry's output.

The type of incentive which will be most effective will vary with the desired goal and the cost of providing this incentive. Regional stimulation may be most efficiently induced by local tax measures, while industry stimulation is frequently prompted through production credits or tariff controls. However, whatever the purpose of the incentive, the mechanism most commonly employed by government to effect this increased investment is the tax system, because the bureaucratic apparatus for the administration of the incentive is already in place.

Incentives for expansion of investment or output provided by the federal tax system usually affect either the amount or the timing of cash flows. The investment tax credit provides an immediate cash inflow (provided there is taxable income) through a reduction in taxes by a specified portion of the investment outlay. A production credit reduces taxes by a percentage of the value of output. Both of these incentives increase total cash flow, though they differ with respect to their effect on the timing of these flows.

Other types of incentives affect only the timing of cash flows, but not their total amount. Accelerated depreciation provides the most important example of this type of incentive. Rules governing the classification of particular outlays as capital expenses, to be recovered through depreciation or upon disposition of the asset, or as deductible expenses recoverable immediately, can also be seen as primarily affecting the timing of cash flows.

Incentives that affect the amount of cash flows and those which affect their timing are related by the concept of the time value of money, which provides that money received today is more valuable, by some percentage, than money received in the future. That percentage, or discount rate, reflects inflation and the rate of return of alternative investment opportunities. Both types of incentives change the present value of future cash flows, the first by making those flows larger, and the second by making them less remote in time. Because the relative impact on a firm's investment of incentives with different time-profiles of benefits will depend upon the discount rate employed by the firm, and similarly the relative cost of these incentives to the treasury will depend upon the "social discount rate," for any given pattern of private and social discount rates, tax rates, and asset life there exists one type of incentive which will be theoretically optimal in reaching the desired goal [1].

In the case of incentives designed to stimulate investment activity in energy-related fields, reliance has been predominately upon price and tax measures which change the present value of investment in the project. The Revenue Act of 1978 contains measures which provide additional tax credits for special types of energy property, the treatment of certain outlays as intangible drilling costs, and special depletion provisions.

Residential tax credits are also provided to stimulate final demand for energy from alternative sources. As will be detailed in Chapter IX, other parts of the 1978 energy legislation remove price controls on certain classes of natural gas. All of these incentives are designed to stimulate the development of sources of alternative energy by increasing overall cash flows, or by distributing their incidence to the earlier years of project life. They concentrate entirely upon the manipulation of the present value of the project.

Government dependence upon incentives which increase project present value ignores one of the major criteria used by private enterprise for project evaluation--the "risk-iness" of the project in relation to projects with comparable projected rates of return. There exists a great deal of uncertainty in the potential returns of any long-term project in today's inflationary environment. This uncertainty* is magnified for large-scale alternative energy projects because a combination of factors, including future resource availability and prices, capital costs and rates, environmental and political constraints, and the danger of technological obsolescence, creates a high degree of uncertainty about potential returns. Given the very large investments required to exploit some alternative energy sources, these projects often appear "too risky" for private enterprise at any politically acceptable rate of return which might be brought about by an incentive package.

Rather than stimulate investment, government programs and regulations may often have the opposite effect, by increasing the degree of uncertainty. John Hanley, president of Monsanto Corporation, says "regulation injects new uncertainties into the already risky business of innovation," [4] and a former member of the Federal Power Commission, reviewing the Natural Gas Policy Act, contends "the uncertainty resulting from attempts to administer this bill will freeze risk capital and scare off new investment in natural gas, at least for a number of years, rather than attracting billions of dollars in investment, as the act was supposed to do" [5].

This chapter is concerned with the evaluation of investment in an energy project and makes explicit the sources and effects of uncertainty from the viewpoint of the potential investor. A model which represents the major variables affecting the present value of an investment in a reservoir development project in a world of certainty is presented. Potential methodologies for introducing uncertainty into this model are briefly reviewed with respect to their theoretical validity and practicality of application. Finally, various means of alleviating risk, both through special types of incentives and through various degrees of participation by different parties, are explored.

C. A PRESENT VALUE MODEL OF BASIN DEVELOPMENT WITH CERTAINTY

The economic viability of the development of a reservoir is a function of the value of the fuel drawn out of the reservoir and the cost of producing this fuel. The value of production is related to the expected price of the product and the amount of recoverable resources. Costs are related to such geological factors as reservoir depth, accessibility and permeability, and to economic factors such as plant and drilling costs, tax policies and the financial structure of the investment.

*In this study Knight's [2] distinction between "risk," as defining a situation with a known probability distribution, and "uncertainty," where the probability distribution is unknown, will not be rigorously maintained. While the distinction is conceptually useful for understanding a businessman's reluctance to invest in speculative energy projects involving a large number of unknowns, as opposed to decisions based upon better-known probability distributions which result from prior experience, as a practical matter all decisions require some estimates of probability of various outcomes. Moreover, it is not the distinction which is commonly made between the two terms. "Uncertainty" is usually used to imply the probability of various outcomes of a project, some of which may be positive and others negative. "Risk," on the other hand, focuses on the potential for a negative project outcome. An article in a businessman's journal defines risk as "the chance or probability that the investor will not receive his expected or required rate of return" [3]. In the present study the two terms will be used interchangeably, although the concept of uncertainty is the most theoretically appropriate for the analysis.

Moreover, it is not the absolute difference between the value of production and costs which will determine whether the investment will be undertaken, but the timing of these flows and the rate at which their values are discounted back through time.

These relationships may be modeled for a hypothetical reservoir development investment decision [6]. Reservoir size, in recoverable barrels of homogeneous fluid, is denoted as r . A production profile of the time sequence by which a quantity of fluid q_t will be drawn from a reservoir of size r is:

$$q_t = \lambda_t r. \quad (1)$$

Associated with a reservoir of this size will be a required level of investment to develop it,

$$I = I(r), \quad (2)$$

which can itself be broken down into a time-sequenced investment schedule

$$I_t = \beta_t I. \quad (3)$$

In order to finance required investment levels there will probably be both an investment of equity capital and debt financing, each with their associated costs. The cost of equity investment is a fraction of yearly investment outlay,

$$E_t = \gamma I_t \quad (4)$$

while the remainder of investment is financed through debt, requiring the payment of yearly debt service S_t :

$$S_t = S[(1 - \gamma)I_t]. \quad (5)$$

The yearly costs of operation are a function of yearly production and reservoir size,

$$C_t = C(q_t, r). \quad (6)$$

The last variable entering the cash flow equation is F_t , the yearly tax paid upon production, based upon yearly production and the fiscal policies and accounting procedures which determine calculated profit π_t :

$$F_t = F(q_t, \pi_t). \quad (7)$$

This variable, like so many of the other variables in this model, is really a surrogate for a variety of fiscal variables such as royalty payments, severance taxes, corporate taxes, and regulations concerning depletion and depreciation. It is important to emphasize the time subscript to the calculated profit variable π_t , because many taxation rules affect the timing of profit flows rather than their aggregate amount.

Given this time-sequenced flow of costs and revenues, the operator will undertake the investment if the present value of the cash flow is positive. This present value for a given reservoir is given by:

$$PV(r) = \sum_{t=1}^T \frac{p_t q_t - (E_t + S_t + C_t + F_t)}{(1 + g)^t} \quad (8)$$

where p_t is the product price, g is the discount rate, and T is the life of the reservoir. For given values of these variables, there is a minimum economic reservoir size which can be calculated by setting $PV(r) = 0$ and solving for r . As conditions change, as when the price of the fluid rises, the minimum economic reservoir size declines. If we conceptually expand the model to include a vector of possible energy sources and their associated prices, conditions may change so that resources which were not economically feasible to utilize take on positive present values. Likewise, deliberate manipulation of these variables may encourage the development of previously unprofitable reservoirs and energy sources.

D. UNCERTAINTY IN A RESERVOIR DEVELOPMENT PROJECT

In a world of certainty, the model presented above provides an unambiguous criterion for the evaluation of a reservoir development project. In situations where investment capital is unlimited, the firm should invest in all projects which exhibit a positive present value, while with limited capital, it should rank these projects in descending order of their present values and invest according to this ranking until investment capital is exhausted.

When there exists a range of possible values attaching to one or more of the variables in the present value equation and investment capital is limited, the criteria for project evaluation must differentiate among investment alternatives not only on the basis of their expected present values, but also with regard for all other values which have positive probabilities of occurring. Before examining some alternative methods of project evaluation under uncertainty, however, a more complete understanding of the types of uncertainty which are prevalent in large-scale energy projects requires examination of each of the variables in the present value equation and its contribution to overall project uncertainty.

D.1. Types of Uncertainty in Reservoir Development Projects

Certainly the most obvious uncertainty in an energy development project, although perhaps not of the greatest potential magnitude, concerns those reservoir parameters which determine the quantity and time pattern of recovery of the resource. Uncertainty in the distribution of these parameters will be termed geophysical risk. Within the terms of the model, these parameters would include the size of the reservoir (r), its flow rate (λ_t) determining the time-pattern of resource production (q_t), and the duration of that production (T).

A closer examination of these parameters reveals the model is too simple to adequately represent the complexity of the geophysical factors. In particular, the assumption of a homogeneous resource (q) glosses over important attributes of the resource, the characteristics of which must be made explicit in the project evaluation. As we have shown, the geopressed-geothermal resource can be broken down into at least two components, methane and thermal energy, distinguishing two important parameters, methane saturation and temperature. These parameters can in turn be related to a series of geophysical characteristics of the reservoir such as porosity, salinity, permeability, and pressure. Prior to drilling the exact values of these parameters are unknown and can only be described in terms of a distribution of potential values, each with an assigned probability of occurring.

Energy companies have a great deal of experience in dealing with geophysical risks in oil and gas production. Reservoir size within a given geologic unit generally follows a log-normal distribution [7]. This specification of the probability distribution allows the exploration company to frame its decisions within a known probability distribution and, with repeated sampling (well-drilling) to approximate the expected outcome. Were the distributions of the other variables in the present value equation known with this degree of certainty, this would closely approximate the conception of "risk" on Knight's risk-uncertainty continuum. The value of obtaining additional information to better specify the distribution of one or more of the parameters can be compared with the cost of that information, providing an interim decision between acceptance and rejection of the project [8]. This ratio will be in part determined by the sensitivity of changes in the overall distribution of project present values to changes in the distribution of the given parameter. The concept of sensitivity will be very useful in our analysis of risk and the structure of incentives.

Some geophysical parameters, such as the flow rate (λ_t) and the lifetime of the reservoir (T), also have a non-geophysical dimension [9]. The flow rate is determined in part by reservoir characteristics such as porosity and permeability, and partly by

factors such as regulation and market considerations. Even the "maximum" flow rate must be related to the diameter of the bore, which is determined by the additional costs of a larger bore relative to the additional output obtainable.

The geophysical aspect of the reservoir duration is a simple function of its size and flow rate. In this sense T represents $T_{\max}$, the maximum duration of the project*. However, there exists the finite possibility that the project will be terminated before $T_{\max}$. This probability exists for all undertakings, but those of a highly technical nature are particularly vulnerable because the processes which they are using may become technologically obsolete.

For large-scale energy projects, the probability of early termination becomes greater. Technological obsolescence is even more probable, because of the large infusion of funds into the development of forms of energy which are potentially inexpensive, such as solar and fusion. Moreover, political pressure resulting from potential environmental hazards may lead to termination long before the project has become profitable, as evidenced by the recent shut-down of the nuclear plant on Three Mile Island. These risks, which are often paramount in such decisions as those by a utility on the form of energy to use for power generation, can be lumped together along with others of a similar nature as catastrophic risks.

The difference between geophysical risks and catastrophic risks illustrates two important concepts with regard to the analysis of uncertainty. Most obviously, although these risks may affect the same variables, the resulting probability distributions of potential outcomes are very different. Figure 4-1(a) represents a probability distribution of reservoir duration as affected by predominately geophysical factors, and is represented as a log-normal distribution, while Figure 4-1(b), the distribution of potential durations due to catastrophic risks, joins two rectangular distributions indicating complete uncertainty within a certain range of durations.

Figure 1(a) Geophysical Risk

Figure 1(b) Catastrophic Risk

Figure 4-1: TYPES OF RISK AND PROJECT DURATION

In addition to affecting the variable in different ways, these risks are subject to reduction through different methods and by different agents. The geophysical aspect of reservoir duration and, in general, most classes of geophysical uncertainties may be reduced by information obtained through more exploration and testing. This might involve a change in the probability distribution, affecting not only the variance of

*Returning again to Knight's risk-uncertainty continuum, the knowledge bought would move the distribution from a position of uncertainty towards one of risk, which can be evaluated more accurately with quantitative tools.

the distribution but also its expected value, or it might only decrease the uncertainty surrounding the expected value. The firm can undertake this research itself, or it may reduce these risks by making a dry-hole contribution to partially finance exploratory operations by another company (the concept of sharing will be reviewed in a later section). In cases where little is known about the resource, groups of companies or the government might be the most appropriate agent for reducing geophysical uncertainty.

Catastrophic risks are unified by the fact that their probability of occurrence cannot be ascertained with any accuracy, nor can these risks be reduced by greater expenditures on research. While environmental risks can be reduced through expenditures on certain types of capital equipment, which are often a significant part of total project investment [10], the term "catastrophic" implies the assumption of a high probability that the event will not occur, and the low but unknown probability that it will. Thus this risk is important only because the outcome of the project is very sensitive to it, and not because of its high probability of occurrence. As it cannot be diminished by the individual firm, this risk can only be reduced by "truncating" the distribution at some point, through insurance, loan guarantees, or market guarantees. This remedy carries an inherent contradiction; however, because the inability to assign probabilities implies an "essential uninsurability" against this type of risk by private insurance companies [11]. Therefore the government must often assume the role of "insurer of last resort."

Having introduced the concepts of differences in the probability distributions of parameters corresponding to different types of risks, their analogous differences in methods and agents of risk reduction, and the sensitivity of the overall distribution of project present values to the distributions of various parameters, the following discussion of other types of risks in a reservoir development project will proceed rapidly. Uncertainties about the values of the remaining variables of the present value formula can be classified into three types: market risks, financial risks, and regulatory risks. Each variable exhibits its own particular distribution of potential values and consequently is subject to different methods and agents of risk reduction. These methods will be discussed in general terms in the last section of this chapter, and specifically related to geopressured-geothermal projects in Chapter XI.

Market risks primarily involve the price of the product (p_t), the costs of plant and equipment (I_t), and the yearly costs of production (C_t). The price of the product (also subject to regulatory risk) will vary with the costs of utilization of other forms of energy, and is therefore highly uncertain. Moreover, it is usually the variable which has the greatest effect upon overall project profitability [12]. Its critical nature to project evaluation is often made explicit by assuming a certain minimum necessary rate of return and solving for the minimum product price to support this rate of return. Complex models which project energy prices into the future are available [13], but it is impossible to resolve the differences in their projections without detailed examination of their assumptions and relationships. This is a difficult matter to undertake within the scope of most project evaluations.

The costs of plant and equipment and operation costs can often be estimated with a high degree of accuracy for the time period in which the project evaluation takes place. Future costs, however, like product price, are subject to a variety of macro-economic factors completely out of control of the individual firm and even of the most powerful national agencies. Moreover, the timing of these costs (β_t) is itself a variable, subject especially to regulatory risk, and affects the total amount of investment required. Inflation in construction costs has been much higher for energy projects than that in other sectors of the economy, with construction costs for electric utilities increasing 112 percent between 1965 and 1975, compared to a 65 percent increase for the consumer price index (see Chapter VI). Unequal rates of inflation and the complexity of energy price prediction make clearly inappropriate the assumption of "constant dollars," or equal inflation of all prices and costs, for evaluation of large-scale energy projects.

Financial risks relate to the means of raising capital for the project, given by the project debt/equity ratio ($[1-\delta]/\delta$), the effect of changes in this ratio on the firm's financial structure, the rate of interest (S), and the desired rate of return at which future costs and returns are discounted (g). Together, these determine yearly debt service (S_t) and costs of equity capital (E_t).

The degree of financial risk which the project developer must bear is related to the overall riskiness of the project and its potential effect upon the firm. Debt or equity capital can be raised at a lower cost and for longer lengths of time when the project is of low risk or when its failure would not materially affect the project.

developer. If these conditions are not met, project financing may be available for only short durations, involving reemergence into the financial market under a new and unpredictable set of conditions.

The last type of risk which may affect the variability of project returns is regulatory risk. This risk includes price regulation (p_t), regulatory treatment of items for rate base and tax purposes (Π_t), environmental controls and the costs of administration of regulations affecting yearly costs (C_t) and total investment (I), and the effect of regulatory action upon the timing of investment (β_t) and production (q_t).

The uncertainty with respect to the effect of regulation on the timing of cash flows is perhaps the most pervasive of all regulatory risks. Utilities are subject to regulatory lags between their incurring increased costs and the inclusion of these costs in their rate base, the duration of which is unpredictable within their highly politicized environment. Delays in acquisition of necessary permits may greatly increase construction times, so that interest charges during construction, the effect of inflation upon the cost of materials and overhead, and other time-related costs become predominant in overall project costs. In contrast to the two to four years it required during the last decade to build an electricity generating plant, it now takes from eight to ten years to complete a coal plant and ten to twelve years for a nuclear plant [14]. While the increased scale of modern generation plants is a factor, it alone cannot account for these large increases in construction times. The delays resulting from labyrinthine government regulations are generally felt to be a significant factor.

Each of these types of uncertainty affects some of the variables in the project present value equation, and there is no variable (with the possible exception of the discounting factor) which is not affected by one or more of these risks. Each variable therefore exhibits a relatively unknown distribution of possible values. Uncertainties about the value of these variables cause uncertainty in the distribution of present values of project cash flows. Moreover, the variance in total project present values is not merely a linear combination of the variances of these individual variables, but rather is affected by the relationships among these variables (their covariance). Thus, as regulatory risk increases potential construction time, there may be a systematic relationship between the rise in construction costs and yearly operating costs.

Explicit examination of the uncertainties affecting a project's present value emphasizes their multidimensional character--the economic, political, and technical nature of these risks can be only artificially separated, and the distribution of any one variable probably reflects aspects of each. Thus an analysis of project risk based entirely upon the technical dimension, such as that by Dhillon and El-Sawy [15], is inadequate in its scope. Their model defines project risk as the "utilization efficiency" (measured in purely geophysical dimensions) of the process of conversion of geothermal resources into energy. The rate at which cash flows are discounted is increased to compensate for this degree of technical risk. The model fails to distinguish between projects involving completely different degrees of financial risk, market risk, and regulatory risk, and can serve neither as the basis for a firm's investment decisions nor as an adequate conceptual tool to understand risk and the structure of incentives.

Having defined the variety of sources of uncertainty in the distribution of project present values, we can examine more critically the methods used by the firm in evaluating project risks. The concept of risk aversion and the utility function will provide the bases for discussion of the optimal structure of incentives, while knowledge of the tools used by the private sector in investment decisions provides the empirical foundation for designing incentives to stimulate investment in energy projects.

D.2. Project Evaluation with Uncertainty

The most frequently used method of evaluating risky investment projects is to use the average or expected value of yearly cash flows (the summation of the value of each potential outcome multiplied by its probability of occurrence), and to discount these values at a higher rate for projects involving a greater degree of risk. A low-risk investment, such as the replacement of machinery, would be discounted at a low rate to reflect the rate of return available on alternative

investments with similar risks. For the corporation, this might be the rate obtainable in the money market, reflecting the cost of borrowed funds. Riskier projects would be discounted at higher rates, so that they would have to be potentially more profitable to be acceptable alternatives.

The major advantage of this method of handling uncertainties in project present values is its simplicity. Risk is reflected in two ways; probabilities of various outcomes (the shape of the distribution) influence expected present value, and the tradeoff between risk and rate of return is made explicit by adding a risk premium to the required rate of return. All project cash flows can be reduced to a single number and compared with those available on other potential investments.

The simplicity of this decision rule carries a high cost, however. The first aspect of this cost is that the effect of the discount factor upon cash flows is dependent upon the timing of these cash flows, with more distant cash flows worth less than current flows. The discount factor is therefore used to represent two different concepts--the time-value of future cash flows and their uncertainty. These two concepts need not bear any relationship to one another. The majority of project uncertainties, for instance, may occur during the first few years of project life during which total investment and reservoir size are determined. Once production is flowing at a constant rate, total project risks may be substantially reduced. The utilization of a risk-adjusted discount rate, by equating risk and time, greatly diminishes these certain but future cash flows and may lead to a negative evaluation of the project. Explicit recognition of the sources of risk in the project is important if the method used for project evaluation is to adequately represent the reality of the situation.

The second negative aspect of the risk-adjusted expected value method of project evaluation is that the actual outcome of the project may lie far from its expected value on the distribution of potential returns. Expected value is only an average, aggregating all characteristics of the distribution into one value. Only with repeated sampling (investment) from this distribution would the outcome approximate its expected value. This implies the assumption of unlimited capital, allowing opportunity for repeated investments of the same type. While some types of projects, such as oil exploration, involve reasonably well-defined expected values, it is rare that capital for investment is not severely constrained. When this is the case, failure of one or a series of investments may exhaust investment capital, foreclosing the opportunity for further "sampling" from the distribution. The investor will go broke because of "gambler's ruin" [16], despite the expectation of a positive project return.

The negative results which may occur from a one-time investment emphasize the importance of considering the entire distribution of possible outcomes of the project. As each variable in the equation may take a number of values, the practical applications of a method of project evaluation which enumerates all possibilities were until recently limited. However, assigning random values to each parameter from a distribution chosen to represent the potential variability of the parameter is now possible through the application of computer simulation techniques. One type of simulation is called the Monte Carlo method, emphasizing the chance nature of the process [17]. This method is commonly used by large firms engaged in complex risky decisions, such as arise in oil exploration. Many other firms explicitly perform an abridged evaluation of the probabilities of various alternatives through a "systems approach" to decision-making [18].

Simulation of project outcomes illustrates to the firm the combined impact of uncertainty from all sources upon the distribution of potential present values. It is therefore superior to the expected value criterion, which looks only at the average of this distribution. Moreover, this method highlights the effect of each risk upon project outcome. The sensitivity of total project uncertainty to the distributions of the individual parameters may be analyzed, which is analogous to the usual form of sensitivity analysis emphasizing only expected values. Just as total project rate of return may be found to be very sensitive to the value of one parameter, total project risk--the left tail of the distribution of possible present values--may be greatly affected by the uncertainties in only a few parameters. Reduction of one of these risks, such as that of early reservoir depletion through reservoir insurance, may truncate an entire segment of the distribution of present values, not only reducing risk but increasing expected value. If it is found that project risk is particularly sensitive to the value of certain geophysical parameters, more money and time could be applied to definition of these parameters as an interim stage between project acceptance and rejection. The risk-sensitivity analysis thus allows for a sequenced

decision, in which the decision at one point in the decision-tree results from the outcome of a previous choice. Harrison finds this alternative is often preferred to an all-or-nothing commitment to the project:

Most managers and firms do not want to be locked on a course of action where major adverse consequences have a significant probability of occurring. In these circumstances they tend to look for options which retain their flexibility, such as, for example, staged capital expansion, so that they are not irrevocably committed until the critical uncertainties are lessened [19].

We have seen that the derivation of the distribution of project present values from the distributions of the individual variables is both empirically relevant to current decision-making in large-scale projects and is conceptually useful, demonstrating through risk sensitivity analysis the impact of changing the distribution of an individual parameter on the overall distribution. This point will be developed in the last section on risk and incentive structure. This method, however, while making project risks evident, does not specifically incorporate risk into the decision rule as does the simple risk-adjusted discount rate. The firm must still judge whether it can accept the level of risk implicit in the distribution of potential present values.

The only approach which explicitly accounts for the effect of uncertainty upon the decision maker is utility theory. Practical application of this approach is difficult [20], for it involves assigning a subjective "utility factor" (measure of desirability) to each potential outcome. Outcomes which would have an extremely adverse impact upon the firm can be assigned high negative utilities, and the average of the utilities, weighted by their probability of occurrence, provides an unambiguous single number criterion for project selection.

While the practical application of utility theory is limited, it provides a useful conceptual tool for understanding risk-aversion and the trade-off between risk and rate of return. For the individual, this tradeoff is based upon the theory of the decreasing marginal utility of wealth, by which is meant that utility increases with increased wealth, but at a slower rate. This causes the utility function to be concave, as shown in Figure 4-2(a). Were the utility function to be linear throughout its length, expected value would lead to the same decision as would expected utility.

Figure 4-2(a) presents a utility function with the utility values assigned to values of project outcomes. Figure 4-2(b) relates the combination of project risk and present value which are of equal desirability to the firm along a given iso-utility curve (U_1 or U_2). A project with the risk-return relationship given by point B, although riskier than project A (as measured by project variance or other appropriate statistical measures), is equally desirable because this risk is compensated for by an increased project expected value. Project C is always preferable to either, for at the same level of risk a higher expected value can be obtained, so that U_2 defines an iso-utility curve of higher value. Both curves, being concave to the origin, exhibit risk-aversion throughout the range of potential present values. This formulation of the utility function will be used in the following sections to analyze methods of reduction of project uncertainty and the firm's exposure to it.

E. PROJECT SEGMENTATION, SHARING, AND RISK

One of the most common practical means of reducing business risks is by sharing the project income and losses with one or more partners in a constant or variable ratio. Sharing arrangements may be proportional, with each partner assuming a certain percentage of project risks and returns, or they may segment the project into different stages, with exposure to the corresponding risks arising at different stages of the project limited to particular partners.

There are several ways by which sharing may reduce risks. The first is that it allows diversification of the firm's investment portfolio by releasing capital for other projects. Diversification through investment in independent projects has been shown to reduce risk for any level of expected value [21]. Cozzolino demonstrates that there is always an optimal share in any investment project with a positive expected value for a given level of risk-aversion [22]. Diversification is now a well understood concept and has been integrated on a practical level into the field of investment analysis, where there are multiple opportunities for choosing investments with different risk-return profiles.

Figure 2(a)

The Utility of Income

Figure 2(b)

The Risk-Return Tradeoff

Figure 4-2: RISK, RETURN, AND PROJECT UTILITY

Risk may also be reduced by project segmentation. This method, usually involving complex projects with multi-level risks, has received little examination in the literature. Oil exploration companies, however, have for years used complex trading arrangements to reduce the risks which each bears individually. The variety of these arrangements is illustrated in Figure 4-3.

As an example of these arrangements, the owner of a lease may feel the prospects of finding a profitable reservoir are low and therefore prefer not to develop this lease himself. He may "farm-out" the operating interest to another party who will bear all the geophysical risks, while retaining an overriding royalty which carries none of these risks. A slightly higher level of involvement would be to retain a net profits interest, which would pay him a share of the proceeds only after fixed costs have been met.

The potential for risk reduction through project segmentation and sharing is illustrated by another example of several alternative levels of participation in an oil exploration venture. The owner of the lease, assumed to be an oil exploration company, has the following options: (1) don't drill; (2) drill with a 100 percent interest, assuming all costs and receiving all revenue; (3) drill with a 50 percent partner; and (4) "farm-out" the working interest until the operator recovers his expenses, then join the operator in a 50 percent partnership. For simplicity the project is assumed to be either a producing well with a single potential output or a dry hole. These alternatives are presented in Table 4-1.

TABLE 4-1

POTENTIAL PROJECT PRESENT VALUE WITH PROJECT SEGMENTATION AND SHARING

Possible Outcomes	Alternatives			
	(1) Don't Drill	(2) Drill With 100% Interest	(3) Drill With 50% Interest	(4) Farm-out, Back In For 50% Interest
Dry Hole	\$0	-\$ 50,000	-\$ 25,000	\$0
Producing Well	\$0	+\$200,000	+\$100,000	+\$100,000

The expected value of profit is a linear function of the probability of hitting a producing well for each alternative course of action. Figure 4-4 plots the expected profit corresponding to different probabilities of success for each alternative course of action.

Source: C. Jackson Grayson, Jr. Decisions Under Uncertainty: Drilling Decisions by Oil and Gas Operators, Harvard Graduate School of Business Administration, Boston, 1960, p. 192.

Figure 4-3: A SKETCH OF TRADING ARRANGEMENTS

Figure 4-4: POTENTIAL PROJECT PRESENT VALUES FOR VARIOUS SUCCESS LEVELS

The figure shows that if the probability of success exceeds 0.33, then drilling alone (2) is preferable to taking a partner (3) or a farm-out (4). If the probability of success is less than 0.2, the farm-out is the alternative with the highest expected value. Sharing the project on a 50 percent basis and the farm-out represent two different methods of division of risks, the former a proportional division of all project risks and the latter segmenting the project into different phases (before and after pay-back of costs), with the risks assumed by each party different in these two phases.

Project segmentation becomes particularly attractive as a means of risk reduction when the parties involved are in different lines of business and have different levels of risk aversion. In the example above, the owner of the lease may not be an oil exploration firm, so that his limited drilling experience and lack of opportunity for "repeated sampling" by engaging in a number of exploration ventures reduce his willingness to accept exploratory risk. His confidence that the true probability of success of the venture justifies his drilling alone would have to exceed that necessary to induce an oil exploration firm to undertake that course of action. This is the same as saying that the riskiness of different types of ventures varies among potential parties.

Levels of risk aversion also differ among potential project participants [23]. This is particularly important with respect to the segmentation of risks in complex energy projects, such as a geopressured-geothermal project. These types of projects might involve participants with highly divergent levels of risk aversion, such as electric utilities and energy exploration companies. In this case, "electricity producers are not prepared to undertake projects that have a risk of complete failure in the early stages. They are not oriented to taking risks of the magnitude acceptable to natural resource developers [24]." The project may then be segmented, with the resource developer bearing the majority of the geophysical risks and selling the product to the utility. Likewise, the utility may be less averse to regulatory risks because of its greater experience with an environment of close regulation.

In summary, one of the most common means of risk reduction in large and complex projects involves spreading these risks among several parties. Project risks may be shared proportionally, reducing the risk to any one party by reducing his level of participation and allowing him to diversify his portfolio of investments. This method is prevalent where all parties are engaged in a similar line of business, such as oil exploration. The project may also be segmented into different phases, with the risks attaching to each segment borne by a different party. This practice is more common in cases where the project potentially involves parties from diverse lines of business and is based upon their differing perceptions of each type of risk, or upon different degrees of risk aversion to a given amount of risk.

F. RISK AND THE STRUCTURE OF INCENTIVES

Having specified the nature of risk in large-scale energy projects and the means which are commonly used by private enterprise for alleviating these risks, the last section of this chapter will turn to risk-alleviation through government programs. As we have noted, most incentives used to encourage private investment currently rely upon increasing the expected present value of the project. However, this may not be the most efficient expenditure of government resources. Depending upon the firm's utility function which describes their trade-off between risk and rate of return, incentives designed to reduce risks may have a larger impact upon the level of the firm's investment in the project than those which increase expected value.

Figure 4-5: THE UTILITY FUNCTION AND THE STRUCTURE OF INCENTIVES

This point is illustrated in Figure 4-5, representing the utility function of a potential participant in an energy project. The project has a risk-return configuration represented by point A, and it is assumed that this configuration, lying on the iso-utility curve U_1 , is unacceptable to the firm. The firm will accept the project only if the risk-return relationship is such that it lies on or below curve U_2 . The common approach to change this relationship would be to design an incentive structure to increase the expected return of the project from X_1 to X_2 , leaving the riskiness of the project unchanged at σ_1 . However, the same result could be obtained by decreasing the riskiness of the project from σ_1 to σ_2 at the same rate of return. Naturally, which of these types of incentives is optimal will depend upon their relative costs to the government. If these costs are proportional to the percentage change in risk or rate of return, which type of incentive is optimal will depend upon the portion of the utility curve on which the project lies. At point A in Figure 4-5, a large increase in the rate of return is required to increase utility from U_1 to U_2 , while the required decrease in project risk to achieve the same purpose is not so great. The structure of incentives should be designed with the perceived risk and rate of return of the project explicitly recognized.

In a similar manner, the characteristics of the utility functions of each potential participant should be distinguished and utilized in designing the incentive structure. Where the utility function rapidly flattens out, representing a high degree of risk aversion, incentives should emphasize reduction of project risk to induce party participation. In the opposite case, with a utility function which remains more vertical, emphasis may be more properly placed upon increasing project expected value.

Having decided to focus the structure of incentives upon reducing project risks as well as upon increasing expected returns, the question becomes which risks to concentrate upon and how to reduce these risks. The analysis of the sensitivity of total project risk to its different components, discussed earlier, becomes extremely important at this stage. The costs of different risk-reduction incentives can then be compared with their effects upon total project risk, and with the costs of incentives designed to increase project present value. Two distinct types of risk-reduction incentives are illustrated in Figure 4-6.

Figure 4-6: METHODS OF REDUCTION OF PROJECT RISKS

Some incentives Figure 4-6(a) might reduce the spread in the distribution of potential values of the variable, without necessarily affecting the expected return of the project. This type of pattern would be exhibited if the program provided more information to the potential participant, such as government-sponsored test wells and demonstration plants. Other incentives might truncate an entire tail of a distribution, as is illustrated in Figure 4-6(b). Here the variable might be the potential cost of environmental controls, truncated by a government insurance program. Also in this category could be incentives such as price controls and loan guarantees. Specific incentives will be explored in detail later in this report.

G. CONCLUSION

The purpose of this chapter has been to explain the effect of risk upon the level of investment of a private firm in a large-scale energy project. The major conclusion to emerge is that the concept of risk is multi-dimensional, affecting each of the project variables in different ways. If the level of participation of private industry in alternative energy projects is to be elevated, critical uncertainties must be specifically addressed by government incentives. These may include programs which provide more information on certain parameters; programs which insure against contingencies, or incentives designed to increase the participation in a particular stage of the project of the party which can most appropriately bear the type of risk endemic to that stage.

CHAPTER V

THE NATURAL GAS INDUSTRY

A. CHAPTER OVERVIEW

It appears that the natural gas component of the geopressed resource, at least for the next decade or so, will be the component which most drives resource development. In light of this, a thorough understanding of the natural gas industry as it currently stands, and is expected to develop, is fundamental to an understanding of how the geopressed resource might be exploited. This chapter attempts to make such an understanding possible, on a level which is meaningful but below that of an expert.

The chapter first presents basic information about the characteristics of natural gas and the circumstances of its occurrence. It then explains how the industry based on this resource evolved and what the resource supply-demand picture for the industry appears to be. The last two sections deal, respectively, with government/industry interaction (regulation and taxation) and the industry financial structure; these two sections are of necessity more detailed than the rest. In general, the regulatory framework is current through the summer of 1979 and statistical data is current through December of 1977.

B. THE NATURE OF THE RESOURCE

The gas industry in the United States today relies almost exclusively on the production, transportation, and distribution of natural gas. This has not always been the case, however. In fact, in it's earliest days, the industry relied almost exclusively on the distribution of manufactured gas. Because domestic natural gas supplies are now being produced faster than new supplies are being discovered, manufactured gas is expected to re-emerge over the next 20 years as an important resource for the industry.

Natural gas is thought to be formed by the decomposition of organic matter, such as marine animals and plants. This decomposition has, of course, been occurring since organic matter first appeared on earth. Over periods of 1,000's of years, strata in which decomposition was, or one day would be, occurring became buried beneath newer strata of soil. In many instances, the natural gas formed from decomposition in buried strata was unable to rise to the surface of the overburden and escape into the air because portions of the overburden were very dense (had low porosity) and/or contained very few even microscopic passage ways through which the gas could pass (had low permeability). The gas then became trapped in "reservoirs", which might now be located at almost any depth down to 5 miles or so beneath the surface. These reservoirs do not resemble caves but, rather, are typically sandstone formations in which the gas is lodged between the grains of sand.

Natural gas in the reservoir is comprised primarily of methane; this is a compound containing one carbon atom and four hydrogen atoms. Although methane is the primary constituent, ethane, propane, butane, and other heavier hydrocarbons commonly comprise 20 percent of the volume of gas in a reservoir. Nitrogen, carbon dioxide, and hydrogen sulfide gases are also found in many reservoirs [1]. Natural gas which, when extracted, contains hydrocarbons heavier than methane is referred to as "wet". If it contains hydrogen sulfide, it is referred to as "sour". The ethane and other heavier hydrocarbons which make natural gas wet are customarily separated from the methane before it is pressurized and distributed as natural gas; these heavier hydrocarbons, natural gas liquids, are themselves very valuable and further, because they are liquids, might hinder the operation of methane transmission equipment. The hydrogen sulfide must also be removed because it combines with water vapor to form sulfuric acid, a very corrosive compound.

Natural gas is said to be "associated" or "non-associated" depending on whether it is found in the reservoir with or without crude oil. In almost all instances in which a reservoir contains crude oil it will also contain natural gas. The converse is not true, however. Oil decomposes to become natural gas at high temperatures and pressures; therefore, most reservoirs found below 10,000 feet contain only natural gas [2].

Natural gas is extracted, "produced", by the drilling of a well bore from the surface to the reservoir containing the natural gas. The gas then flows spontaneously into the wellbore where pressures are lower than in the surrounding reservoir formation. Typically, 60 to 80 percent of the natural gas in a reservoir can be produced; this is a markedly higher percentage than that which is typical for the production of oil, about 30 percent [3]. Both of these percentages may be raised by various types of enhanced production techniques.

Manufactured gas, during the early days of the gas industry, was a by-product of the combustion of coal or coke. Later, gas was manufactured from crude oil. The principal disadvantage of manufactured gas, compared to natural gas, is that impurities in manufactured gas cause it typically to have only about 60 percent [4] of the energy content found in the same volume of natural gas (1020 Btu/cubic foot [5]). Although as late as 1930 approximately 65 percent of all customers using gas used either manufactured gas or a combination of manufactured and natural gas [6], today less than 1 percent of the gas sold is manufactured [7]. As noted, however, the manufacture of gas, especially from coal, is expected to again become common during the next 20 years.

C. EVOLUTION OF THE INDUSTRY

C.1. Formative Period (Pre-1940's)

The first known "transportation" of natural gas occurred in China sometime around 1,000 B.C. [8]. In this primitive instance, natural gas was conducted from a fissure in the earth through a bamboo pipeline for residential use. Although isolated instances of use similar to this have presumably occurred throughout history, it was not until the advent of gas lighting in the early 1800's that the industry can realistically be said to have begun. It was in 1815 that Rembrandt Peale displayed the benefits of gas lighting in his museum in Baltimore [9]. Public response was enthusiastic and within a year Peale had gathered financial backers and begun the first gas distributorship in the United States. For the next 100 years, gas lighting in urban areas was a principal market for the gas industry. Although the electric lamp was invented in 1879, the advent of the Welsbach mantle in 1885 allowed the gas industry to maintain its dominant position in the illumination field past the turn of the century [10]. By shortly thereafter, gas had made such inroads in industrial and non-lighting residential markets that the gas industry did not much suffer as electricity came to dominate the illumination market.

As the foregoing history suggests, the gas distribution segment of the industry was the first to be established. The gas production segment was established next, though its reason for existence at the time was solely oil production. The gas transmission segment developed much later than the other two.

The major factor retarding growth of the gas industry from the middle 1800's until the 1930's was the absence of any means of transporting gas from its point of origin to the markets where it could be used. Though as early as 1821 natural gas was being transported commercially in Fredonia, New York, this transport occurred through a very inefficient pipeline less than 1 inch in diameter [11]. By 1872, a somewhat more successful line had been laid from Colonel Drake's oil field outside Titusville to carry gas into town [12]. In general, however, neither natural nor manufactured gas could be practically transported over any distance prior to the advent of welded seam pipeline construction.

Partially as a consequence of this, a great deal of natural gas was wasted prior to the 1930's. Reservoirs which produced both natural gas and oil were, in general, produced exclusively for the oil. Associated gas was occasionally reinjected to the producing formation to stimulate further oil recovery, but was more often flared at the wellhead. As late as 1934, 50 percent of the natural gas produced in the Texas panhandle was being flared [13]; the Central Intelligence Agency estimates that 100 trillion cubic feet (100 tcf) of natural gas, a 5-year supply at current consumption rates, has been flared in the United States since 1857 [14]. The simultaneous advent in the late 1920's and early 1930's of resource conservation statutes, which banned the waste of natural gas in the field, and of welded seam pipelines signaled the beginning of tremendous growth in the natural gas industry; producers were forced to sell their gas for any price they could get, as low as 1¢ per 1000 cubic feet (mcf) [15], and the technology which could transport this low-cost fuel to market had finally arrived.

Prior to welded seam technology, pipelines could not sustain the pressures (600 pounds per square inch and greater) which are necessary if natural gas is to be transported economically; lines in which pipe sections were screwed or bolted together typically leaked 20 to 40 percent of the gas product in transit. It was not until 1925 that the first practical long distance, welded seam, pipeline was constructed. This ran from northern Louisiana to Beaumont [16]. By 1931, a truly long distance pipeline (1,000 miles) had been constructed from the Texas panhandle to Chicago [17]. This pipeline was also impressive for its 24-inch diameter. From 1931 on, pipeline technology advanced rapidly and, by 1947, gas from the Texas panhandle was being delivered to the northeast coast [18]. By the time Vermont, the last of the lower 48 states to acquire gas service, began receiving natural gas in 1966 [19], long distance transmission lines in 30 to 40 inch diameters were common.

C.2. Current Industry Structure

As of 1977, the gas transmission segment of the industry had in place more than a quarter of a million miles of transmission pipeline [20]. More than 30 percent of these facilities were located within the five gas producing states (Kansas, Louisiana, New Mexico, Oklahoma, and Texas); from these states, pipelines run to serve markets in the north and along the east and west coasts. This general picture may be expected to change somewhat as manufactured and imported gas come to comprise an increasing percentage of the gas used in the United States. One factor influencing this change is the largest project currently underway in the gas transmission industry (also the largest project ever undertaken in any industry with private financing)--construction of some 4,800 miles of large diameter pipeline to bring natural gas from the North Slope of Alaska to enter the transmission grid for the lower 48 states at points near San Francisco and Chicago.

Cumulative statistics on gas transmission operations which are carried out wholly within the gas producing states are not readily available because, in general, those activities are not regulated by the Federal Energy Regulatory Commission (FERC). In the interstate network, over which the FERC does have jurisdiction, there are 83 pipeline companies which account for approximately 99 percent of the gas sales; these pipeline companies each realized a gross revenue in excess of \$1,000,000 in 1977. Of these 83, there are actually 32 "major" pipelines, each of which in 1977 transported in excess of 50 billion cubic feet of natural gas [21].

With the advent of natural gas shortages in the late 1960's and during the 1970's, most gas transmission companies formed or purchased subsidiaries whose purpose it is to explore for and produce natural gas for sale, usually, to the parent company. These subsidiaries are numbered among the 5,000 to 10,000 [22] oil and gas producers who are thought to comprise the production segment of the domestic natural gas industry. Exploration and production subsidiaries owned by gas pipeline companies have given rise to modest problems in the regulation of their low-risk parent pipeline companies, but have not affected significantly the structure of the gas supply industry.

The domestic gas supply industry continues to be dominated, as it has been for several decades, by 20 to 30 large production firms, most of which are integrated oil and gas producers* [23]. Although the integrated oil and gas producers have an influence on the gas production industry which is many times greater than their numbers within the industry would suggest, this is not uncommon throughout industrial sectors of the US economy. Generally, market power within an industrial sector is thought to be so concentrated as to be undesirable and give rise to anti-competitive practices if the four largest firms in the sector control 50 percent of the market or if the eight largest firms control 70 percent of the market [24]. Several recent analyses of competition within the gas production industry indicate that the top four firms own approximately 27 percent of the proven domestic gas reserves and account for approximately 24 percent of domestic gas production; the top eight firms own approximately 40 percent of the proven domestic natural gas reserves and account for approximately 36 percent of the natural gas production [25]. In an increasingly important area of natural gas production, production from the off-shore continental shelf, there was concern in the mid-1960's that fewer than 10 of the major oil and gas

*An integrated oil and gas company produces and also refines petroleum or markets petroleum through retail outlets (e.g., service stations).

producers might establish such dominance that they would be able to manipulate production in an anti-competitive fashion; the four-firm concentration ratio in 1966 was nearly 44 percent and the eight firm concentration ratio was above 75 percent [26]. However, by the mid-1970's these ratios had dropped to about 21 percent and 40 percent, respectively; this drop in concentration is generally attributed to the fact that off-shore production involves very high risks and very high front-end capital costs, which in the earlier days of off-shore production presented barriers which only the most wealthy of the oil and gas producers could overcome. Although off-shore production is still very risky and expensive, it is now somewhat less so than it was 10 or 15 years ago and, further, smaller oil and gas producers have increasingly gained a role in off-shore production through participation in joint ventures [27].

Comprehensive information on the gas distribution segment of the industry is also not readily available because many of the firms in that segment do not report their activities to the FERC. Further, many of those firms are engaged not only in the distribution of natural gas, but also the generation and distribution of electricity; therefore, manpower, facilities, and various expenses are not easily allocated to one of the two company functions. As of 1977, American Gas Association statistics indicate that there were in place approximately 2/3's of a million miles of domestic distribution mains [28]. As might be expected, these mains tend to be concentrated around industrial and population centers in the northeast. Distribution through these mains is thought to be controlled by some 1600 separate companies, approximately 2/3's of which are investor-owned and approximately 1/3 of which are in some manner owned by local governments [29].

Source: American Gas Association, *Gas Facts*, 1978, (Arlington, Virginia: AGA, 1979), Table 2; n. 1, Table 52.

Figure 5-1: DOMESTIC NATURAL GAS PROVEN RESERVES AND CONSUMPTION

D. INDUSTRY SUPPLY AND DEMAND CHARACTERISTICS

The single most salient characteristic bearing on any segment of the natural gas industry is that consumption of natural gas in this country has exceeded new natural gas discoveries in every year except one since 1968. The exception year is 1970, the year in which natural gas reserves from Alaska began to be counted in the US total. As reflected in Figure 5-1, consumption during the past decade has not been running only slightly ahead of discoveries, but, rather, has often been two or three times discoveries. This is so despite the fact that consumption now is no greater than it was ten years ago and, in fact, is some 14 percent less than it was in the peak year, 1972. Figure 5-1 also reflects that today's proven natural gas reserves, those reserves which should be recoverable under existing economic conditions, will be completely consumed within ten or eleven years at current consumption rates; new discoveries, extensions of existing fields, improved recovery techniques, and changing economic conditions may be expected, of course, to add to tomorrow's proven reserves, though probably in amounts less than consumption.

Figures 5-2 and 5-3 provide a graphic display of the sources of gas supply and consumption in the United States. From Figure 5-2, one sees that approximately 80 percent of the gas produced in the United States is produced from gas wells and that the remaining 20 percent is either associated or dissolved gas produced from oil wells. Approximately 20 percent of the total US production comes from wells located off-shore in Alaska, California, Louisiana, or Texas [30]; nearly all of this production occurs off-shore of Louisiana. Of all the off-shore production, approximately 80 percent occurs on federally owned lands and is therefore gas which flows to the interstate market [31].

Source: Gas Facts, 1977, Tables 14 and 76 (1974-1976 Averages).

Figure 5-2: MID-70'S GAS SUPPLY AND CONSUMPTION
PRODUCTION AND TRANSMISSION SECTORS

As of December, 1977, there were some 145,000 wells producing gas in the United States [32]. Prior to 1973, new gas well completions had run between 3,500 and 5,000 wells per year for some twenty years. In 1973, however, gas well completions jumped up above 6,000. In 1974 and 1975, completions were above 7,000. In 1976, completions were above 9,000. By 1977, new well completions were above 11,000 per year [33]. These rapid increases are generally attributed to the much higher wellhead value of natural gas in recent years. Because of the publicity which accompanies the drilling of very deep wells in the United States, one might mistakenly assume that most new completions are deep wells; in fact, as recently as 1977 the average depth of new on-shore completions was only approximately 5500 feet [34].

The "imports" figure in Figure 5-2 has been growing steadily and, as will be explained in more detail later, is expected to continue growing during the next fifteen to twenty years. Although net imports constituted only 5.5 percent of all the natural gas delivered in the United States in 1977, they have nonetheless doubled in the past ten years [35].

38.7% of total:
Household and Commercial
Consumption
(Approximately 33%
of this was commercial
consumption, 67% was
residential)

45% of total:
Industrial Consumption

16.4% of total:
Electric Utility Power Generation
(Approximately 70% of this was
consumed in Kansas, Louisiana, 2)
Oklahoma, Texas, and New Mexico)

Source: Gas Facts, 1977, Table 50; n.1, Table 63; n.2, Table 68.

Figure 5-3: PATTERN OF GAS CONSUMPTION (1977)

The consumption pattern displayed in Figure 5-3 is based on 1977 statistics for total gas delivered. Approximately 80 percent was delivered by gas utilities [36] and the other 20 percent was delivered by producers directly to end-users or was produced by end-users themselves. Approximately 45 percent of the nonutility gas delivered was delivered to fuel electricity generation; nearly all of the remainder went for other industrial applications [37].

Less than one-half of one percent of the total customers of gas utilities are in the industrial and electricity generation customer categories. However, these categories consumed almost 49 percent of all the utility gas delivered [38]. It is therefore clear why utilities view with some alarm the fact that the number of industrial and electricity generation customers served by the industry has declined 16 percent from its high average during 1972 and 1973. The quantity of gas consumed within this sector has decreased by an even greater percentage, 26 percent [39]. This proportionally larger decrease has come about because increased gas prices have prompted diligent conservation efforts on the part of industry and, also, because the largest consumers of natural gas are also the ones for whom the capital investments required to switch to alternate forms of fuel pose the least burden. The lost volume in sales to the industrial and electricity generation customer segments has caused the gas utilities to place more emphasis on gas storage facilities. This is so because demand in the household and commercial segments of the consumer market is very seasonal, high in the winter months and low in the summer months. Historically, gas utilities dealt with these seasonal fluctuations largely by selling gas to industrial and electricity generation customers on interruptible bases. Then, when household and commercial demand was high during winter months, utilities would meet that demand by interrupting the supply of gas to the large-volume industrial and electricity generation customers; these customers switched to generally more expensive fuel oil during those periods. Because they were interruptible customers, these large-volume customers paid less than they otherwise would have for each Mcf of gas actually

delivered. Although in 1977 41 percent of all industrial and electricity generation customers were still supplied on an interruptible basis by gas utilities [40], the absolute size of the industrial and electricity generation market had declined sufficiently that gas utilities were required to stock storage facilities, typically depleted gas reservoirs, with excess supply during the summer months so that household and commercial customers could be supplied during the winter.

The ability of the industry to supply gas in the future is, of course, less obvious than it was fifteen years ago. However, as Table 5-1 reflects, the industry may well be able to continue supplying increasing amounts of gas through 2000 by increasingly relying on imports and supplemental sources such as coal gasification. The ability of domestic production to continue supplying a significant percentage of the gas consumed in the United States is premised on the belief that increased drilling activity will discover and allow production of reserves which are not yet proven. Industry authorities believe this premise is reasonable and it would seem to be so in light of a 1979 analysis by the American Gas Association which showed that only 40 percent of the natural gas resource in place in the United States had actually been produced as of December, 1978 [41]. Also, as mentioned earlier, natural gas is frequently found below 10,000 feet, whereas oil is not; it is therefore possible that new natural gas fields may be found beneath old oil fields at depths in which oil producers have previously been uninterested.

The AGA analysis also contends that 90 percent of the world's natural gas resource is yet to be produced. This should insure that the rise in imports reflected in Table 5-1 is possible, if customers are willing to pay the price. Most of the increase in imports is contemplated to come from liquefied natural gas imports, although some will also be conventional natural gas from Canada and Mexico. Coal gasification, the manufacture of synthetic natural gas, and the production of natural and synthetic gas by "new technologies" is expected to provide 28 percent of the country's gas consumption by the year 2000.

TABLE 5-1
POTENTIAL U.S. GAS SUPPLIES THROUGH THE YEAR 2000

	(Tcf)					
Source	1978 Actual	1980	1985	1990	1995	2000
CONVENTIONAL (LOWER-48 STATES)	19.1	18-19	16-18	15-17	13.5-15.5	12-14
POTENTIAL SUPPLEMENTALS						
Canadian	0.9	1.4	1.4	1.1	1.0	0.8
SNG	0.3	0.5	0.5	0.5	0.5	0.5
LNG Imports	0.1	0.4	1.6	2.0	2.5	3.0
Mexican Gas	--	0.2	0.5	1.0	1.0	1.0
Alaskan Gas						
Southern	--	--	0.1	0.2	0.3	0.6
North Slope	--	--	0.7	1.4	2.2	3.0
Coal Gasification	--	--	0.1	0.6	1.8	3.3
New Technologies	--	--	0.9	1.8	3.2	5.0
TOTAL, SUPPLEMENTALS	1.3	2.5	5.8	8.6	12.5	17.2
TOTAL	20.4	20.5-21.5	21.8-23.8	23.6-25.6	26.0-28.0	29.2-31.2

Source: American Gas Association, Gas Energy Review, Vol. 7, No. 9 (Arlington, Virginia: AGA, June, 1979), page 12.

Consumption patterns in the future may be contemplated to shift in favor of household and commercial consumption at the expense of industrial and, especially, electricity generation consumption. This assumption is grounded in the prohibitions of the Power Plant and Industrial Fuel Used Act of 1978 which prohibits, subject to some exceptions, the construction of new natural gas-fired electric power plants and major fuel burning installations; most existing electric power plants are not allowed to burn natural gas as a primary fuel after 1990 and the law authorizes the Department of Energy to prohibit the burning of natural gas as boiler fuel in existing major fuel burning installations where it is technically and economically feasible to convert those installations to alternate fuels [42].

E. GOVERNMENT/INDUSTRY INTERACTION

E.1. Section Overview

The natural gas industry, like the rest of the US "private" business sector, interacts with government at all levels from the county or parish to the Office of the President of the United States. This section describes that interaction in the two respects which are most peculiar to the gas industry and which most affect the industry's operations: (1) federal regulation of gas prices and delivery systems and (2) federal taxation of income from gas production; no effort is made to describe other instances of regulatory interaction, such as with the Environmental Protection Agency or the Occupational Safety and Health Administration.

E.2. Natural Gas Industry Regulation

E.2(a) Federal Energy Regulatory Commission Overview. Federal control over the natural gas industry arose because early state actions to control gas transportation worked to the advantage of gas producing states and to the disadvantage of their neighbors. As early, shallow, fields near population centers began to deplete, the states in which the population centers were located attempted to prevent exportation of dwindling gas reserves. Numerous federal court decisions, principal among them Kansas Natural Gas Company vs. Oklahoma [43], decided by the US Supreme Court in 1911, held that state actions such as these were a burden on interstate commerce and hence prohibited by the US constitution.

There was, however, a consensus among state and federal authorities that the natural gas industry--at least the transportation and distribution sectors--was clearly affected with the public interest; a body was needed which could constitutionally regulate the industry in the public interest. The Interstate Commerce Commission (ICC) was given this authority over oil pipeline transportation, where abuses were more flagrant, in 1906 [44] but systematic federal regulation of the gas industry did not begin until enactment of the Natural Gas Act (NGA) of 1938.

The Natural Gas Act was one of a number of public interest regulatory bills passed during the 1930's. The Federal Communications Act (1934) [45], the Public Utilities Holding Company Act (1935) [46], the Civil Aeronautics Act (1938) [47], and the Natural Gas Act (NGA) [48] were all New Deal legislation. The Natural Gas Act vested the Federal Power Commission (FPC), instead of the ICC, with regulatory jurisdiction over (1) the transportation of natural gas in interstate commerce, (2) the sale of natural gas in interstate commerce for resale, and (3) natural gas companies engaged in the transportation or sale for resale of natural gas in interstate commerce [49].

Court and FPC interpretation of the NGA expanded FPC authority to a scope significantly greater than the act's language would have seemed to support [50]; producers whose gas was in some portion co-mingled with gas moving interstate were brought under its jurisdiction, as were non-natural gas companies which carried gas wholly for "in-house" use in pipelines which they owned exclusively for that purpose [51]. In 1954, Congress reacted to states' protests that FPC authority was too pervasive intrastate by passing the Hinshaw Amendment to the NGA [52]. The Hinshaw Amendment allows transmission and distribution companies to purchase interstate gas for transport wholly within the state in which it will be consumed without becoming subject to FPC jurisdiction, if some state agency certifies regulation of this activity. Transmission and distribution companies which do this are often referred to as Hinshaw companies.

By 1938, public utility regulation theory was well developed. Its object was to assure that the buyer of a product or service paid no more than a just and reasonable price. This was done by placing a ceiling on the product price which was only high

enough to allow the seller a reasonable return on prudent capital investments and the recovery of prudent operating expenses. This was basically the theory, known as "cost-of-service" regulation, which the FPC applied to all regulated sectors of the interstate gas industry until 1960, when producers (who really just aren't utilities) began to be treated differently.

In October of 1977, the Federal Energy Regulatory Commission (FERC) succeeded to the gas regulation position formerly held by the FPC. In November of 1978 the Natural Gas Policy Act (NGPA) [53], among other things, extended FERC jurisdiction to allow price regulation of natural gas sold in the intra state markets; it also mandated eventual deregulation of prices received for various classifications of natural gas.

E.2(b) Production Sector Regulation. Prior to 1954, there was considerable doubt that the FPC had any regulatory authority over natural gas producers. Section 1(b) of the Natural Gas Act expressly excludes the "production or gathering" of gas sold interstate from the scope of natural gas company activities to be regulated. Notwithstanding this, the First Phillips Case [54], decided by the U.S. Supreme Court in 1954, declared that the wellhead prices received by producers who sold gas to companies which subsequently resold it in the interstate market were subject to regulation.

Under the regulatory system which prevailed for six years following the First Phillips Case, each producer whose gas was bound for interstate resale or which was co-mingled with gas bound for interstate resale was required to file a rate schedule with the FPC. The FPC could accept or reject a schedule, based on a determination of whether the schedule called for a gas price in excess of a reasonable return on investment and recovery of prudent operating expenses. Producers could not charge gas prices in excess of schedule rates approved by the FPC and could not remove gas production from interstate trade ("abandon" sales) without FPC approval.

The regulatory system used from 1954 to 1960 was cumbersome and resulted in significant delays, primarily because each rate schedule was considered separately. In the year following the First Phillips Case, the FPC received 10,978 rate schedules [55]. Too, the system treated producers as though they were the managers of traditional utilities--where prudent investments do not regularly result in complete failures (dry holes); the inherently poor correlation between the costs of attempted gas discovery and the volumes actually discovered fostered a regulatory policy which insulated imprudent operators from their failures and denied shrewd operators rewards they would otherwise have received. The policy (and its successors over the next 25 years) also discouraged exploration for new gas supplies because, among other things, it put on the successful producer the burden to justify his operations in an area in which there was no historical standard by which to infer "reasonableness." Finally, the policy highlighted the difficulty of allocating costs between oil and gas operations.

In the Second Phillips Case (1960) [56], the FPC announced that it would henceforth regulate producers' prices on an area basis, setting price ceilings by area and examining only those rate schedules which contemplated prices in excess of ceilings. This decision did not affect non-price regulation of producers. It also did not much affect delays in rate approval, largely because it took years to determine appropriate price ceilings for an area (by which time, new ceilings were in order)*.

It was during this era that the FPC began to "vintage" gas, that is, began to set higher ceilings for gas produced from wells spudded after a certain date than for gas flowing on that date. The theory behind vintaging was that higher prices for new gas would prompt discovery of new gas, whereas allowing higher prices for old gas would unfairly enrich producers; in fact, most authorities now agree that vintaging discouraged full development of old gas reservoirs, unwisely discounted the importance of overall cash flow as a stimulus to discovery, and fostered regulatory intricacies which themselves discouraged new gas exploration.

In the early 1970's, the FPC moved to eliminate some of the delays and regulatory overhead which accompanied even the area rate setting system. In June of 1974, the FPC began setting interstate wellhead gas prices on a nationwide basis. For new gas (from wells spudded after January 1, 1973), the nationwide rate was \$.42/Mcf. Six

*Five years elapsed between the Second Phillips Case decision and the Permian Basin Rate Case [57], which actually established the first rate ceilings for an area.

months later, the rate was boosted to \$.50/Mcf, plus annual escalations. In July of 1976, the nationwide rate was boosted to \$1.42/Mcf for gas produced from wells spudded after January 1, 1975; this rate also included a price escalator [58]. It was during this time that FPC control of interstate wellhead gas prices began to shift dramatically from a scheme which set prices on the basis of production costs to a scheme which set prices at incentive levels which were higher than costs. This was done primarily in an effort to call forth new gas discoveries because, with the exception of 1970, each year since 1967 had seen domestic production volumes exceed proven discoveries (see Figure 5-1); the crude oil prices set by the OPEC cartel, of course, also strongly affected FPC policy concerning interstate wellhead gas ceiling prices.

TABLE 5-2

INTERSTATE NATURAL GAS CURTAILMENTS FROM

FIRM CONTRACT COMMITMENTS

YEAR (APRIL-MARCH)	FIRM COMMIT- MENTS* (tcf)	VOLUME CURTAILED* (tcf)	CURTAILMENTS/ COMMITMENTS (%)
1970-71 ¹	-	.2	-
1971-72 ²	-	.5	-
1972-73 ²	18.9	1.1	5.9
1973-74	18.8	1.6	8.3
1974-75	18.7	2.6	14.2
1975-76	18.1	3.6	19.8
1976-77	18.5	4.2	22.9
1977-78 ⁺	18.5	4.7	25.5

*Includes volumes committed and curtailed between pipelines. Some volumes are therefore counted twice. FPC corrections are available for years from 1974 and indicate that double counting alters final column percentages less than 1%.
+Projected

Source: n.1: Albert F. Bass, "Curtailments of Natural Gas Service," DOE Monthly Energy Review, January, 1976, p.4.
n.2: Federal Power Commission, "Firm Requirements and Curtailments of Major Interstate Pipeline Companies," Bureau of Natural Gas Staff Report, September, 1973, Schedule I.
Other Data: Federal Power Commission, "Requirements and Curtailments of Interstate Pipeline Companies Based on Form 16 Reports," Bureau of Natural Gas Staff Reports, June, 1974-1977, Schedules I.

TABLE 5-3

AVERAGE WELLHEAD PRICE OF NATURAL GAS IN TEXAS

(nominal cents per mcf)

YEAR	SOLD TO INTERSTATE MARKET	SOLD TO INTRASTATE MARKET
1955	9.9	4.9
1960	13.6	7.8
1965	15.0	10.0
1970	16.7	12.1
1972	19.1	13.9
1973	21.77	15.6
1974	24.97	26.3
1975	31.59	51.18
1976	32.59	71.26
1977	47.04	96.81
1978	58.70	110.07
1979	72.17	117.82

Note: 1976-1979 figures are arithmetic averages of quarterly figures.

Source: 1955-1972: Stevens and Cumming, Texas Energy: A Twenty-Five Year History, Governor's Energy Advisory Council (Austin, Texas: Office of the Governor, 1977), p.102.

1973-1979: Lloyd Roland, Comptroller's Office, State of Texas, personal communication (November, 1979).

The low price ceilings which the FPC historically set for gas sold in the interstate market are frequently cited as the cause of the gas shortages which that market experienced during the 1970's. This oversimplifies the problem. It is true, as reflected by Table 5-2, that supply shortfalls in the interstate market reached alarming levels during the 1970's, and it is true that intrastate markets fared much better during those times. However, it is not accurate to say that FPC price ceilings have historically been too "low"; as Table 5-3 reflects, producers who sold gas under FPC jurisdiction enjoyed, until the 1970's, a large price advantage over those who sold gas intrastate. The inability of the regulatory apparatus to respond rapidly as the energy supply picture changed was much more a handicap to the interstate market than were low prices per se. Also, the concurrence within a short time span of the decline of domestic natural gas reserves and the disappearance of presumed secure

supplies of cheap imported crude oil, combined with the per btu price differential oil has always held over natural gas*, call into question assertions that a pure free market gas pricing system would have prevented supply shortfalls.

Under the NGPA, natural gas sold in intrastate or interstate markets is subject to wellhead price regulation by the FERC. The NGPA established numerous categories of natural gas and assigned to various categories various wellhead price ceilings, all of which escalate at or above the rate of inflation. The wellhead prices for four categories of natural gas will eventually become decontrolled under the provisions of NGPA. New (April 20, 1977) natural gas prices will be decontrolled on January 1, 1985, as will pre-November 8, 1978, intrastate gas which is selling at December, 1984, contract prices in excess of \$1/million Btu's (approximately \$1/Mcf). Prices for new on-shore production well natural gas which was not committed to interstate commerce on April 20, 1977, and which comes from a horizon below 5,000 feet will be decontrolled on January 1, 1985; similar gas from horizons above 5,000 feet will not be controlled until July 1, 1987. The prices on high-cost natural gas, such as geopressured methane, from wells on which drilling began after February 18, 1977, will be decontrolled on the date of the first incremental pricing rule, which must be promulgated by November 8, 1979. All other natural gas, principally gas which was committed to interstate commerce on April 20, 1977, and gas which was committed to intrastate commerce on November 8, 1978, but which will have a contract price of less than \$1/million Btu's on December 31, 1984, will remain subject to FERC-regulated price control indefinitely [60].

E.2(c) Transmission Sector Regulation. From the early 1800's when "city gas" began to be distributed within the city of Baltimore, the general public has claimed an interest in the rules by which gas is delivered to consumers. This claim was first recognized on national level by US Supreme Court in 1889, in the case of Gibbs v. Consolidated Gas Company, [61]. This case announced that public regulation of gas delivery systems was legal because of the public interest in those systems.

As previously suggested the depletion of natural gas reservoirs which were located near population centers in the northeast gave rise to protectionist policies in states with more abundant gas reserves. The federal courts struck down many of these policies in a series of cases, the most notable of which is Kansas Natural Gas Company vs Oklahoma [62], in which the Supreme Court overruled the state of Oklahoma's attempt to prohibit natural gas pipelines operating within that state from crossing the state borders. These cases developed a legal framework in which state governments could control the production and local distribution of gas, but in which no one controlled the systems by which natural gas was transported from one state to another. This changed in 1938 with passage of the NGA.

The regulatory theory on which the FPC operated in regard to interstate gas transmission companies was, and is, that those companies should be allowed to earn revenues each year sufficient to cover (1) annual utility operating expenses, (2) annual depreciation on utility property, (3) annual taxes associated with utility operations, and (4) a reasonable rate of return on prudent capital investments. Operating expenses and capital investments are deemed to be prudent if they are wise from an economic or business perspective and if they further public convenience or meet public necessity. As a means of insuring that capital investments, such as transmission lines and pumping facilities, are prudent, the transmission company contemplating the investment must first secure a certificate of public convenience and necessity.

The system by which the FPC regulated interstate transmission companies was a boon for those companies in that it guaranteed each of them a return on capital investments, a guarantee which most businesses, of course, did not have. One of the prices exacted for this security was, however, a moderate ceiling on the potential profits to be made from gas transmission and a considerable loss of discretion on the part of those who "ran" gas transmission companies. Regulated companies also suffered

*In 1960, 1965, and 1970, crude oil wellhead prices were uncontrolled and averaged (per barrel): \$2.88, \$2.86, and 3.18, respectively [59]. Using a Btu equivalent of 5.6 mcf natural gas = 1 barrel crude oil, these oil prices correspond to \$.51, \$.51, and \$.57 per mcf. Compare these prices to those in Table 5-3.

the now-familiar overhead burdens (lawyers and paperwork) which accompany regulation. It was settled early on that where a transmission company conducted both jurisdictional (interstate) activities and nonjurisdictional activities, such as gathering or local distribution, all of its activities were subject to FPC scrutiny [63].

It was not clear from the language of the NGA that the FPC had jurisdiction over the transportation in interstate commerce of gas which was not bound for resale; this might be gas which was bound for industrial customers, perhaps taken by those customers directly from the transmission lines. The advent of World War II, however, gave rise to a number of unusual and expedited regulatory practices, one of which was the more or less perfunctory granting of a certificate of public convenience and necessity for the transportation of natural gas to non-resale end-users. Such certification therefore came to be accepted by both gas transmission companies and their direct sale customers. It was not until the 1950's that the FPC's jurisdiction in this area was much tested. The issue was largely resolved in favor of FPC jurisdiction in that, although the price of direct sale natural gas was determined not to be regulated by the FPC, the interstate transmission of that gas was subject to regulation; this gave the FPC *de facto* control over the prices negotiated between the industrial purchaser and the interstate pipeline company [64].

The 1970's brought about sweeping changes in the regulatory framework in which gas transmission companies operate. These changes have come about principally because of shortages in gas supply, though the NGPA's provisions for phased decontrol of certain gas prices will also affect transmission company regulation.

Beginning in 1970, various interstate pipeline companies began to have non-interruptible supply obligations during the winter months which exceeded the delivery capability of those pipelines. As supplies became tight, gas producers marketed their new gas supplies to the intrastate market, where unregulated gas prices rose in response to supply shortages (See Table 5-3). In a belated attempt to encourage discovery of natural gas for the interstate market, the FPC during the early to mid-1970's began to allow interstate pipeline companies to make advance payments to oil and gas producers for the exploration and development of natural gas reserves for the interstate market [65]. In the instances where reserves were in fact discovered and developed, the pipeline advance payments were repayed in natural gas; in other cases, the pipelines recovered these payments from their own rate payers. This emergency program was extended twice, but finally abandoned in December, 1975 [66]. The FPC felt that a review of the sources to which these advance payments were being applied indicated that the payments were being used primarily to finance exploration and development of offshore natural gas reserves, which would have in most cases been bound for the interstate market even in the absence of the advance payment program.

In an effort to deal in a systematic fashion with the gas shortages, interstate pipeline companies developed curtailment plans which established the priorities by which the gas supplies of customers were to be withheld during times of shortages. These curtailment plans were developed independently by the pipeline companies and approved by the FPC. Although the priorities within these curtailment plans varied from pipeline to pipeline, in general they followed this format [67]:

- a. Priority One (last to be curtailed). Residential and small commercial (less than 50 mcf on a peak day) users; institutions, such as schools, hospitals, and governmental agencies were considered to be commercial users;
- b. Priority Two. Large commercial users and firm (non-interruptible) industrial customers who needed natural gas for plant protection, feedstock, and process uses;
- c. Priority Three. Firm industrial customers using less than 1500 mcf/day as boiler fuel and other firm industrial customers who, regardless of the uses to which they put the natural gas, did not have alternate fuel capabilities to meet their requirements;
- d. Priority Four. Firm industrial customers who used between 1500 and 3000 mcf/per day of natural gas for boiler fuel and who had alternate fuel capabilities;
- e. Priority Five. Firm industrial customers who used more than 3000 mcf/day of gas for boiler fuel and who had alternate fuel capabilities;
- f. Priorities Six through Nine. Interruptible customers in various volumetric use categories.

Curtailment plans based on this hierarchy were referred to as "end-use" plans. They did not contemplate delivery to a customer of gas volumes in excess of those delivered during some "base" period. The FPC and, later the FERC, generally required that all users of natural gas at a low priority be curtailed before users in the next priority up were affected. Agricultural users of natural gas were considered to be industrial users. Table 5-2 shows the extent of past interstate curtailments below contract amounts;

Sections 401 and 402 of the NGPA mandate a priority system based more on the user's end product than on the manner in which the gas is used. Under the NGPA, residential, small commercial, institutional, and certain other specially designated uses of natural gas are given highest priority. Essential agricultural uses, which includes natural fiber production, for which alternate fuels are not economically practicable and reasonably available receive the next highest priority. Although it is the duty of the FERC to insure that natural gas being delivered to customers in this second priority level is in fact being used for essential agricultural uses, the Secretary of the Department of Agriculture actually determines what those uses are and the volumes of gas which are required. The next lowest priority mandated by the NGPA is for uses of natural gas in essential industrial process and feedstock applications, where alternate fuels are not economically practicable and reasonably available. Presumably, boiler fuel uses not included in the first or second priority levels are next in line.

The FERC has attempted to reconcile existing pipeline curtailment plans with the mandates of the NGPA by requiring that interstate pipelines superimpose the NGPA standards on the standards previously approved by the FERC. The principal significance of this is that firms which produce products which are defined to be agricultural products are less likely than previously to have their natural gas supplies curtailed, even if the natural gas is being used in boiler applications. Conversely, manufacturers who use natural gas as feedstock or for process heat purposes will find themselves more subject to curtailment under the NGPA standards. The secretary of the Department of Agriculture has defined the "essential agriculture use" category rather broadly, as the NGPA does appear to contemplate [68]. Consequently, in addition to obvious food production and processing uses such as irrigation pumping, produce drying, or food cooking, the term also encompasses the use of natural gas for the production of beer, chewing gum, pet food, food containers, pesticides and preservatives, and in sulfur mining; in some of these latter instances, only non-boiler uses qualify. In a significant departure from previous curtailment standards, the NGPA allows the Secretary of the Department of Energy, through the Economic Regulatory Administration, to provide that interstate pipeline companies deliver volumes of natural gas for essential agricultural uses which are sufficient to meet the "current" requirements of the user, as long as those requirements do not exceed the volumes for which the user and the pipeline or Hinshaw distributor have contracted [69]. At this writing (June, 1979), the regulations concerning the delivery of natural gas for industrial process and feedstock needs have not been promulgated but these are also anticipated to allow load growth. Table 5-4 provides an outline comparison of curtailment schemes before and after passage of the NGPA.

As the curtailment plans previously discussed have evolved, they have always been applied to natural gas owned by the interstate pipeline companies and sold by those companies. This and the FPC's desire to stimulate the flow of natural gas into interstate commerce led, during the 1970's, to a regulatory framework which permits a small but growing common carriage role for pipeline companies.

In August, 1975, the FPC issued its final form for ORDER 533 [70]. Order 533 allowed interstate pipeline companies to receive two-year emergency certificates of public convenience and necessity for the transportation of natural gas purchased by customers who were large commercial users or industrial users of natural gas for plant protection, feedstock, or process needs. These customers were required to purchase the gas from natural gas producers who were not affiliated with the interstate pipeline companies and were further required to be customers facing a possibility of curtailment. Although the prices which the customers paid the producers for 533 gas was not a matter over which the FPC or FERC had formal regulatory authority, it appears that some *de facto* control of sales prices was exercised in determining whether or not to grant the emergency transportation certificates. The amount of gas which could be transported under a 533 certificate was limited to the amount by which the end user was curtailed.

Although this program was very limited in scope--unavailable, for example, for local distribution companies--it was significant because it marked a first time that interstate pipeline companies had been allowed to carry gas other than gas which they

owned. Practices similar to this are of course common to the transportation of crude oil, but these practices have given rise to the really significant antitrust problems which lie at the heart of the divestiture movement with which integrated energy producers must contend. In February, 1978, the FERC extended the Order 533 program, with modest changes. Under the extension (Order 2 [71]), more attention is paid to the alternate fuel capability of the purchaser and, for the first time, reserves which the purchaser owns in place are eligible for two-year transportation certificates.

With the passage of the NGPA in November 1978, the FERC gained control of the first sale price of all natural gas, including gas sold by the producer directly to the user. At this time the Public Utility Regulatory Policy Act also amended the Natural Gas Act of 1938 to allow the FERC to certify transportation of user-owned natural gas on a non-emergency basis.

TABLE 5-4

OUTLINE OF PIPELINE CURTAILMENT PRIORITIES

PRE-1979 CURTAILMENT SCHEME (18 CFR 2.78)

- PRIORITY 1: Residential & small commercial ("commercial" here includes schools, government buildings, etc.)
- PRIORITY 2: Large commercial & firm industrial if used for plant protection, feedstock or process needs ("Industrial" here includes agricultural uses)
- PRIORITY 3: All firm and interruptible industrial uses not covered by Priority 2 and which lack alternative fuel capability; firm industrial boiler fuel use less than 1500 Mcf/day with alternative fuel capability; and interruptible uses of less than 300 Mcf/day with alternative fuel capability
- PRIORITY 4: Firm industrial boiler fuel uses between 1500 & 3000 Mcf/day, with alternative fuel capability
- PRIORITY 5: Firm industrial boiler fuel uses greater than 3000 Mcf/day, with alternative fuel capability
- PRIORITIES 6-9: Various volumes of interruptible supplies

POST-1979 CURTAILMENT SCHEME (18 CFR 281)

- PRIORITY 1: Residential, small commercial, schools, and hospitals, and uses for police protection, fire protection, sanitation facilities, and correctional facilities
- PRIORITY 2: Unless alternative fuels are economically practicable and reasonably available:
- (a) Essential agricultural uses (including boiler fuel uses) such as: agricultural and natural fiber production, food processing, irrigation, and crop drying; and
 - (b) Essential agricultural uses (process & feedstock uses only) such as production of fertilizer, agricultural chemicals, and animal food.
- SUBSEQUENT PRIORITIES: Pre-1979 priorities, to extent individual uses have not been elevated to priority 1 or 2 above.

Note: Post-1979 curtailment scheme allows load growth for priority 2 uses. Similarly, many priority 2 users are entitled to receive full current volumetric gas requirements (subject to contract limits), and are not therefore limited to base year volumes.

The FERC has exercised its authority under this amendment to authorize the granting of 5-year certificates of public convenience and necessity to interstate pipeline companies wishing to transport natural gas owned by "high priority" users. These users may not be residential customers or local distribution companies, but may desire to use natural gas as boiler fuel and may have their gas transported regardless of alternate fuel capability. The volumes of gas which may be transported under these "direct sales" certificates are not limited to volumes of which curtailment is feared. The user-owners need not, as they were required to be under Order 533, be current customers of the interstate pipeline company which would carry the gas. The FERC says it will "entertain" applications for 10-year certificates for the carriage of natural gas produced by the end user; this provision is apparently intended to encourage large energy users to undertake the exploration and development of gas reserves on their own. FERC implementation of this authority is not yet complete and, although it is now mostly helpful only to essential agricultural users with alternate fuel capability, the direct sales certification program may later be extended to industrial feedstock, process, and possibly boiler fuel customers.

In May 1979, the FERC provided for emergency 1-year certificates for the transportation of natural gas purchased by industrial and electric utility end-users of natural gas, including those who use it for boiler fuel, if the gas transported is to be used to displace imported fuel oil [72]. This program is currently designed to address short-term crude oil import problems and ends in June, 1980. As is the case under other programs which allow transportation of user-owned natural gas, gas transported under this program is not subject to curtailment because of general supply shortages.

Table 5-5 provides an outline comparison of the FERC programs under which user-owned supplies of natural gas may be transported interstate.

With the approach of the winter of 1977, federal government officials were concerned that curtailment plans and emergency direct purchase programs might not be adequate to address the problems of shortages which would arise during the 1977-78 winter heating season. In response to this concern the Congress passed the Emergency Natural Gas Act [73]. This act empowered the President to allocate natural gas supplies owned by one interstate pipeline company to another interstate pipeline company in the event that the second company did not have adequate gas supplies to meet the needs of high priority users. This act was extended for the 1978-79 winter season, as well, and was incorporated, with modest changes, in the NGPA of 1978 [74].

Under the emergency allocation provisions of the NGPA, the President must first declare a "natural gas supply emergency"; this may be declared for up to 120 days and may be extended beyond that period. During a natural gas supply emergency and after an interstate pipeline company has curtailed completely low priority uses of natural gas, the President may authorize any interstate pipeline company or Hinshaw distributor to contract with (1) any natural gas producer not affiliated with the purchaser, (2) any intrastate pipeline, (3) any local distribution company, or (4) anyone else other than an interstate pipeline company for the purchase of emergency supplies of natural gas. These purchases are to be allowed under 4-month contracts, which may be renewed.

If these purchases are not adequate to meet the needs of the interstate pipeline company, the President may then, under a provision of the Public Utility Regulatory Policy Act, prohibit the burning of natural gas as boiler fuel in existing major fuel burning installations or electric power plants [75]; this prohibition is subject to any exemptions the President wishes to allow and is only applicable in the event that fuel oil is available and usable as a substitute for withheld natural gas supplies. This prohibition would apply to user-owned supplies of natural gas. If this prohibition does not free up adequate supplies of natural gas to satisfy high priority uses, the President may then begin to allocate general pipeline supply gas among interstate pipeline companies to meet those uses. Finally, and only in the event that all the preceding emergency measures have been taken, the President may allocate user-owned natural gas to high priority customers.

Sweeping federal intervention, such as gas allocation among pipelines, is not likely to be necessary during the next three or four years, however, because provisions of the NGPA now make it possible for interstate pipelines to acquire surplus gas supplies owned by or committed to intrastate lines [76]. Intrastate markets are currently (1978-79) unable to clear all the natural gas which is available there; the surplus is thought to be approximately 2 tcf annually [77]. Under NGPA Section 311(b), intrastate pipelines are now allowed to sell this surplus to interstate lines and all distribution companies under two-year, renewable, authorizations; under NGPA

Section 312, intrastate pipelines may now assign to interstate lines and all distributors rights to receive surplus gas which they (the intrastate lines) have under producer commitments. Depending on the duration of the intrastate surplus and the willingness of intrastate lines to enter into these low-profit transactions, these two provisions of the NGPA may be expected to greatly reduce short-term supply shortfalls in the interstate market.

The final significant regulatory change to which interstate pipeline companies have been subjected during the 1970's involves application of the incremental pricing rule of Title II of the NGPA [78]. The incremental pricing provisions arise because other provisions of the NGPA call for phased decontrol of the wellhead prices of several categories of natural gas.

TABLE 5-5

FERC CERTIFICATION FOR INTERSTATE TRANSPORTATION OF USER-OWNED GAS

	Order 533	Order 2	NGA Section 7(c)(2)	Order 30 Fuel Oil Displacement
Qualified User	Large commercial and firm or interruptible industrial users which are existing customers of the transporting pipeline and which do not have alternative fuel capability. Fear of imminent curtailment required.		User need not previously have been a pipeline customer. Availability of alternative fuel capability not considered. Fear of imminent curtailment not required.	Industrial concerns and electric utilities using fuel oil
Qualified Use	Non-resale; non-boiler		Non-resale; essential agricultural, school, hospital or similar institutional use; see note	Non-resale; displacement of fuel oil
Source of Ownership	Purchased at wellhead from producer not affiliated with an interstate pipeline	Same as 533, plus purchased or developed reserves in place	Gas purchased at wellhead; reserves purchased in place; gas produced by user	Any but purchase from interstate pipeline company
Qualified Gas		All but Federal Off-shore Continental Shale	All but gas dedicated to interstate commerce on 11/8/78; waiver available	Any not dedicated to interstate commerce
Volumetric Limitation	Amount of anticipated curtailment		None	Fuel oil displacement; subject to interruption for higher priority users
Certification Period (Maximum)	2 years	2 years, plus 6 months if gas contract is "take or pay"; renewable	5 years; renewable; 10-year certification will be entered for user-developed and produced gas	Program currently scheduled to end June, 1980

Note: As of July, 1979, use for industrial feedstock and process applications is still under consideration.

Phased decontrol will, of course, allow the price producers receive to rise and, therefore, will ultimately lead to higher gas costs for consumers. Policymakers decided it would be desirable for industrial consumers to bear a disproportionate share of these increased costs. Under the incremental pricing provisions, industrial users of natural gas as boiler fuel and other industrial users identified by the FERC must pay so much of the first sale purchase price of natural gas as the interstate pipeline companies which supply them paid which was in excess of the "incremental pricing threshold". The incremental pricing threshold is in most cases determined by the FERC, though in some cases, as in the case of "high cost natural gas", it is set by statute. The price differential between the incremental pricing threshold and the first sale purchase price may be passed along to the industrial end-user only until the price paid by that end-user reaches the "burner tip" cost of alternate fuels; the FERC is to determine what the appropriate alternate fuels and their respective pricing levels are. At this writing, FERC implementation of these provisions is not complete. It is likely that alternate fuel price ceilings will in fact be so close to the incremental pricing threshold that industrial end-users of natural gas subject to the incremental pricing regulations will not be much deterred from using natural gas solely because of those regulations. The gas transmission industry is nonetheless generally displeased with the incremental pricing concept because, apart from negative effects it may have in the industrial consumer market, its implementation adds significantly to their paperwork overhead.

E.2(d) Distribution Sector Regulation. There is less federal jurisdiction over distribution companies than over producers or transmission companies. Currently, only distributors whose transmission lines actually run interstate are under direct federal jurisdiction by virtue of their gas transportation activities; others are regulated at the state level.

The Natural Gas Act of 1938 specifically excluded from federal regulation "the local distribution of natural gas or...., the facilities used for such a distribution" [79]. However, what the First Phillips Case did for producers, the East Ohio Gas Company Case [80] (1950) did for distributors; many of their activities were brought under FPC regulation. This produced a great deal of friction between state authorities and the FPC because state regulation of intrastate distribution companies was well established by this time. In 1954, Congress passed an amendment to the Natural Gas Act known as the "Hinshaw Amendment" [81], which dealt with problems caused by the East Ohio Gas Company Case. The Hinshaw Amendment specifically exempted from FPC jurisdiction the transportation intrastate of gas for resale intrastate, even though the gas may have been produced out of state, if the intrastate transportation were regulated by a state authority.

State regulation of distribution companies varies among states, but rests in each case on some application of the cost of service model of utility regulation.

The principal drawback to this model, from the distributors' perspective, is that its application requires costly and dilatory "rate hearings", at which actual costs of service and appropriate rates of return are determined. Distributors during the past decade have had to project highly uncertain future costs on the dubious basis of "representative" past costs; the number of subjective questions this raises and the increased level of public awareness regarding utility regulation have led to protracted and sometimes acrimonious hearings. "Unpredictable" future gas prices have led to general regulatory allowances that distributors' increased wholesale gas purchase prices may be "flowed through" to customers without the necessity of full rate hearings. This is, of course, open to criticism because it lessens a distributor's incentive to secure supplies at the lowest possible price. Flow-through adjustments are also generally not permitted for other than increased fossil fuel purchase costs, so that other investments which might tend to increase supply or reduce demand (such as development of alternative fuel supplies or installation of conservation equipment) may not be financed this way [82].

Expenses which may be included in a distributor's rate base of course have a real impact on how the distributor plans to deal with potential shortages. Issues of concern here include current allowance for gas storage costs, allowance for investment in non-fossil fuel energy conservation or production equipment, and allowances for exploration advances to producers. Each of these issues puts the regulatory body in the precarious position of balancing low consumer prices, secure consumer supplies, and adequate rates of return to stockholders, each of whose "safe" utility investment realizes earnings as a variable percentage of a utility's net capital assets.

E.3. Federal Income Taxation of Oil and Gas Production

E.3(a) Background on Federal Income Taxation of Oil and Gas Producers. There are few issues in federal income taxation which have generated such debate over a long period of time as the specific tax provisions applying to the production of mineral resources, and particularly to oil and gas production. The deduction given for percentage depletion became an important political issue in the 1960's, and was seen by the general populace as one of the more notorious federal "giveaways" to big business. However, percentage depletion is only one part of the total tax package which is specific to the oil and gas industry. This section will outline the major features of the taxation of oil and gas producers, indicating how these tax provisions effect profitability and how they, therefore, affect the actions of producers by providing incentives for particular types of investments and particular organizational forms.

The two distinctive tax provisions related to income from mineral production are allowance for depletion of the reservoir and the expensing of intangible drilling and development costs. The concept of depletion as an expense is valid within generally accepted accounting practices, as the asset obtained by exploration and drilling (the reservoir) is a "wasting asset", which is used up in the course of production much as is a building or a machine. The problem with depletion arises from the lack of a direct relationship between the costs of exploration and development of the resource, which are like the costs of erecting a building or buying a machine, and the returns to be realized from the investment.

In a normal business operation, the costs of the capital equipment and operating expenses will determine the price of the product sold. If the price greatly exceeds costs in a competitive market, entrepreneurs will enter the market, selling the product for a lower price until all producers can only earn a normal profit on their total costs of production, which include the costs of recovery of capital assets. Thus, competition should insure that there is a direct relationship between the cost of the asset and the returns to be realized from it. The original cost of the asset (or replacement cost, in an inflationary economy) can logically be divided by its useful life to determine the portion of the cost realized each year and subtracted from total revenue in determining income taxes.

In the exploration and development of mineral resources no such direct relationship between costs and returns exists. A great deal of money may be invested with little or no return, or a small investment in a wildcat hole may yield astronomical returns. Early tax law tried to recognize this break between investment and returns by direct valuation of the reservoir at the time of discovery. While the Revenue Act of 1916 [83] made no distinction between mining and other types of industry in its rules governing deductions for capital consumption, the Revenue Act of 1918 [84] allowed depletion to be based upon discovery value of the reservoir, if this value was "materially disproportionate" to costs. The discovery value would be the fair market value of the deposit, including all costs of recovering the deposit.

The determination of fair market value obviously proved to be very difficult. Therefore, in 1926, Congress decided to allow a rule-of-thumb deduction to correspond to "discovery value depletion"; this deduction was based upon the typical relation between discovery value deductions and gross income from the property over the preceding years. The rule-of-thumb was that the yearly depletion of the fair market value of the reservoir corresponded to 27½ percent of the yearly gross income from the reservoir. The producer thus had (and still has, in some cases) the ability to use the higher of cost or percentage depletion in determining expenses to be charged against net income for recovery of the economic value of his wasting asset. Moreover, he could continue to claim the allowed percentage of gross income as depletion long after the cost of investment had been recovered [85].

The other tax provision which forms a part of the peculiar tax package for oil and gas producers is the allowance to treat a certain portion of the expenses of drilling and developing a well as current expenses rather than as an addition to capital assets. These "intangible drilling and development costs," which are costs incurred prior to the completion of the well and which are not specifically represented by tangible materials, can be deducted along with current operating expenses in determining net income. In a normal business operation, these costs would be capitalized along with materials costs and amortized over the life of the property. In the case of an oil and gas producer, this would result in these costs being separated from the costs of tangible capital equipment, which is depreciated, and added to the accumulated investment in the reservoir (the basis) to be recovered through cost depletion.

Percentage depletion, when it is available, and the expensing of intangible drilling costs certainly together form a distinctive and, perhaps, inequitable tax structure for the oil and gas industry. A producer may in a sense recover his investment twice over; first by deducting a good part of his actual costs of drilling and development as intangibles, and second by claiming percentage depletion which was intended to serve the same purpose. Along these lines Stephen McDonald, a noted economist in the field of oil and gas, observes:

The history of the percentage depletion provision indicates that it was intended to be an administratively more feasible equivalent of discovery value depletion...Logically, then, discovery value depletion (hence percentage depletion) is an alternative to depletion based on costs. But...the use of discovery value (or its supposed equivalent, percentage depletion) did not (and does not) preclude the additional deduction from gross income of nearly all the actual outlays of explorers in making discoveries and preparing their properties for production [86].

Although the availability of the percentage depletion deduction has been greatly circumscribed recently, the tax structure of the oil and gas industry remains a hotly debated topic. A recent study of the "effective tax rate" for the oil and gas extraction industry found that it was taxed at rates higher than those of other industries [87]. However, this study is subject to the qualifications resulting from the definition of "effective tax rate" and the difficult task of separating oil and gas extraction from other phases of the industry. A conflicting study found that the combined tax incentives allowed to the industry result in the equivalent of an investment tax credit of 46 percent on investment in production [88].

The remainder of this section will treat in detail the specific provisions pertaining to these two major tax provisions, the types of property interests in oil and gas reserves which result in various types of tax treatment, and the organizational forms and accounting practices of the industry relevant to income taxation.

E.3.(b) Depletion. Physical depletion is a concept relating to the exhaustion of a wasting asset, corresponding to which is a fall in the economic value of the asset, known as economic depletion. The Internal Revenue Service (IRS) allows the owner of an economic interest in minerals in place to be compensated for this reduction in value through an annual deduction from gross taxable income. However, although the concept relates to the physical exhaustion of the resource, the depletion deduction is dependent on income being generated from the sale of the product, not on the amount of the product extracted from the reservoir. One consequence of this is that no depletion deduction is allowed for minerals consumed in the operation of the property.

The depletion deduction is allowed only to owners of an "economic interest in minerals in place" [89] and not to all participants in the income stream generated by the property. The meaning of the quoted phrase is extremely complicated. The various types of property interests which are contained within the term "economic interest" will be covered in more detail later in this section. For the present, a listing of those parties with an economic interest would include owners of working operating interests, royalties, overriding royalties, production payments, and net profits interests. The importance of the concept can be illustrated by the process of an exploration company obtaining a lease from the owner of the mineral rights to the property. Any money paid for this lease is viewed as an advance royalty, and since royalty ownership is included as an economic interest in the minerals, the recipient of this money may in some cases deduct a percentage of the sum received as percentage depletion.

The IRS code provides for two methods of computing depletion: Cost depletion and percentage depletion [90]. If cost depletion is used, the basis (net "cost" to the taxpayer) of the depleting property is multiplied by the ratio of (1) the number of resource units sold during the year to (2) the number of resource units estimated to have been available for production at the beginning of the year; the resulting figure is the cost depletion deduction allowed for the year. If cost depletion is used, intangible drilling costs which were expensed as they were incurred are not considered when the basis of the property is calculated.

The Tax Reduction Act of 1975 [91] repealed the percentage depletion for most owners of oil and gas interests. Only (1) producers who sell natural gas under contracts in effect in February, 1975, at prices which do not allow producer recovery of increased tax expenses and (2) royalty holders and small producers who do not

conduct refining or retail marketing activities may now claim percentage depletion deductions. Though many people with an economic interest in oil and gas in place fall within one of the classes for which the deduction has not been repealed, the large oil and gas producers do not. Those who qualify may deduct annually a percentage of their gross income from each property; the percentage is 22% now and will decrease to 15% in 1984 and thereafter [92]. Intangible drilling cost deductions have no bearing on the percentage depletion deduction because the latter deduction is not tied to the basis of the property. Indeed, percentage depletion deductions may be claimed, subject in some cases to a minimum tax, even after their aggregate amount exceeds the taxpayer's basis in the property. Percentage depletion deductions are limited to 50% of the taxpayer's taxable income from the depleting property (figured without the depletion deduction) and to 65% of the taxpayer's taxable income from all sources [93].

Since percentage depletion is calculated on gross income from the property, the calculation of "gross income" and the definition of "the property" become crucial. A "separate property" is a mineral interest in a reservoir owned by the taxpayer non-contiguous to another such mineral interest. "Gross income" includes all income from sale of the mineral, excluding any portion of that income which is generated from conversion or further refining of the product from the well. The IRS has recognized that there is a separation process which is normal and necessary to produce a marketable product, but warns: "when the processes performed...are more extensive than simple separation, such as is sometimes the case in gas plants and recycling plants, it is possible that the operation of the facility involves both producing and manufacturing processes" [94]. In this case a portion of gross income is assigned to a manufacturing process and denied depletion.

Percentage depletion, where available, is generally more advantageous for the taxpayer than cost depletion. The magnitude of this advantage will depend upon three factors: the difference between the amount of percentage depletion and cost depletion which can be claimed; the proportion of total outlays which can be treated as intangibles, and as such eliminated from the basis for cost depletion; and the rate at which the firm discounts future dollars relative to present dollars. In a highly inflationary business environment, the mere deferral of taxes from the present to the future can mean a large increase in real after-tax cash flow. In a non-inflationary world, the accelerated expensing of accumulated costs through percentage depletion and expensing intangibles would only result in tax savings if the firm were growing. If present and future capital outlays were equal in real dollar costs, expenses over the long run would tend to equalize under either method.

E.3(c) Depreciation and Investment Credit. Most of the general rules of depreciation apply equally to the oil and gas industry. All costs of capital equipment which are represented by tangible property with a salvage value may be accumulated on the basis of the property and amortized over its useful life through depreciation. Depreciable property includes pumps and housing, pipelines to storage tanks and the tanks themselves, well casings, and derricks. Tangible property may be depreciated by straight line depreciation, units of production depreciation, or accelerated methods of depreciation. As with other industries, when property is sold which has been subject to an accelerated method of depreciation, some portion of this depreciation must be recaptured (added to the basis and taxed at ordinary rates).

The oil and gas industry differs from other industries in that some portion of the value of assets normally depreciated can be expensed as intangibles and eliminated from the depreciable basis of the property. If the taxpayer has elected to expense intangibles, the costs of installation of tangible producing equipment is expensed in the year installed; if he has elected to capitalize intangibles, these costs will be added to the depreciable basis of the property and recovered through depreciation. This option in the treatment of intangible installation costs ends with completion of the well, defined by the IRS as installation of the Christmas tree. After this point all installation costs become part of the depreciable basis of the property [95].

The costs of drilling wells which are not subject to depletion are also recovered through depreciation. The only wells which fall within this category are those which are not directly related to the production of the mineral. Thus, while water and gas injection wells are considered part of the production phases of the operation, salt water disposal wells are considered operating facilities, the total costs of which must be capitalized and recovered through depreciation [96].

All well and lease equipment which can be depreciated is subject to an investment tax credit of 10 percent of a specified portion of its costs. This portion varies from one-third for property with a life of three to five years, to two-thirds for property with a life of five to seven years, and to 100% for a property with a useful life of over seven years [97]. This credit may be deducted directly from the tax bill, and so exceeds the value of a deduction by an amount equal to $(1 - \text{tax rate})$.

E.3(d) Intangible Drilling and Development Costs. The division of total costs of capital equipment into costs represented by tangible equipment and costs associated with installation of this equipment, with the latter allowed as an expense to be charged against current income, departs from the accepted principles of taxation of all other industries. Until 1954, there was no statutory authorization for the expensing of intangibles. However, it had been an accepted method of tax accounting since an early revenue ruling on the Revenue Act of 1916 [98].

Intangible drilling costs in general are costs with no salvage value, and include wages, fuel, repairs, and hauling supplies incidental to the drilling, shooting, or cleaning of wells; clearing, draining, building roads, surveying, and geological work to prepare for drilling; and construction of derricks, tanks, pipelines, and other physical structures necessary to drill wells and prepare for production. As previously mentioned, the well is regarded as complete when the Christmas tree is installed and all costs related to installation of physical facilities to this point may be considered intangibles.

The owner of an operating interest has the option to capitalize intangibles (as taxpayers in other industries are required to do), recovering them through depletion or depreciation, or add them to current expenses to be charged against current income. Owners of types of economic interests in the property other than operating interests, such as royalty interests or production interests, are not entitled to claim intangible drilling and development costs although they are entitled to claim depletion.

Only rarely will a firm capitalize the costs of intangibles because capitalized costs are recovered incrementally over time and the total recovery will never exceed the front-end costs. Percentage depletion, however, may continue to be taken long after the unrecovered basis of the property has been reduced to zero. Therefore, the addition of intangible drilling costs to the basis through their capitalization would be of little value for a firm computing depletion by the percentage method. If the taxpayer does elect to capitalize intangible drilling costs, he is granted a second election to capitalize or charge to expense the portion of intangibles attributable to dry or unproductive wells [99].

Like accelerated depreciation, a portion of intangible drilling costs allowed after 1975 must be recaptured (subtracted from the basis) upon sale or exchange of the property. This amount is equal to the lesser of the value of intangible deductions taken over those which could have taken through cost depletion or the amount realized in the sale over the adjusted basis of the property.

A summary of the tax treatment of expenditures in the finding, development, and production of oil and gas is given in Table 5-6.

E.3(e) Property Interests and their Taxation. The importance of different types of property interests for taxation has already been indicated in discussion of depletion and intangible drilling costs. Depletion is allowed only to an owner of an "economic interest in minerals in place," while the tax treatment of intangibles applies to the owner of a working or operating interest in these minerals. Moreover, the transfer of some types of economic interests are considered sales, upon which income may be realized and taxed at the capital gains rate. This subsection will consider the different types of economic interests which can be created in minerals and their respective taxation. As this is perhaps the most complex subject in oil and gas taxation, only the most common types of property interests and transactions will be explicitly discussed.

The most general property interest in oil and gas production is an economic interest in minerals in place. The regulations contain the following description:

An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in mineral in place...and secures, by any form of legal relationship, income derived from the extraction of the mineral...to which he must look for a return on his capital [100].

TABLE 5-6
TAX ACCOUNTING TREATMENT OF EXPENDITURES IN THE FINDING,
DEVELOPMENT, AND PRODUCTION OF OIL AND GAS

EXPENDITURES	TAX TREATMENT
1. Dry hole costs	1. Expensed as incurred ^a
2. Lease rentals	2. Expensed as incurred
3. Lease acquisition costs	3. Capitalized upon acquisition
a. Leases later proved unproductive	a. Capitalized cost charged off as loss upon surrender of lease ^b
b. Leases later proved productive	b. Capitalized cost recoverable as such only through cost depletion
4. Other exploration expense (such as geophysics, geology)	4. Capitalized if on an area of interest, ^c otherwise expensed as incurred
a. Areas later proved unproductive	a. Capitalized costs charged off as a loss upon surrender of property ^d
b. Areas later proved productive	b. Capitalized cost recoverable as such only through cost depletion
5. Intangible drilling costs of producing wells	5. Option of expensing as incurred or capitalizing and recovering through cost depletion ^d
6. Tangible equipment on producing wells	6. Capitalized and recovered through depreciation
7. General lease equipment on producing properties	7. Capitalized and recovered through depreciation
8. Production costs	8. Expensed as incurred

^aTaxpayers electing to capitalize intangible drilling costs have the additional option of either expensing or capitalizing dry hole costs. The option to capitalize intangibles is almost never used.

^bOr upon final determination of worthlessness of mineral rights without immediate surrender of the property.

^cAn area of interest is one in which further exploratory work is at least conditionally contemplated.

^dCapitalized intangible costs incurred in the installation of casing and equipment and in the construction on the premises of derricks and other physical structures are recoverable through depreciation.

Source: Stephen L. McDonald, Federal Tax Treatment of Income from Oil and Gas, Brookings Institution (Washington, D.C. 1963), p. 17.

A fine line exists between an economic interest in minerals in place, entitling the owner to a share of the proceeds, and a payment from the proceeds of production which does not imply ownership of a part of the production. For example, in the Bankline Case [101] the taxpayer was the owner of a gasoline plant and had contracted to extract gasoline from wet gas for a percentage of the proceeds from the sale. The Supreme Court held that the taxpayer had no capital investment in the mineral deposit, so did not own an economic interest in the property and was not entitled to depletion.

On the other hand, the Hudson Case [102] held that the assignment of a fractional interest in the heavier hydrocarbons in place, in exchange for the assignee's agreement to construct a plant to extract these liquids from wet gas, did create for the assignee an economic interest. The principal difference is that the latter case explicitly assigned an interest in the producing property. These two cases emphasize the importance of explicit consideration of tax ramifications of different types of contractual arrangements.

Prior to all efforts of exploration and development the economic interest corresponds totally with ownership of the mineral rights of the property, which may or may not correspond to ownership of the surface rights. If a party other than the owner becomes interested in exploring this property for potential development of its mineral resources, he obtains from the owner of the mineral rights (lessor) a lease, allowing him to enter, survey, locate, drill and remove any minerals found for a period of years or as long as production is obtained. In consideration for this, he usually pays the lessor a lease bonus, a delay rental until production begins, and a royalty (1/8 to 3/16 of the gross value of production). The interest acquired by the lessee is called the working interest or operating interest, while that retained by the lessor is called the royalty interest. Both of these interests constitute economic interests, and any payments corresponding to them are subject to depletion. The lease bonus, for example, is considered an advance royalty paid to the royalty owner subject to percentage depletion. For the lessee it becomes a cost of acquiring the lease, capitalized and subject to cost depletion. If the property becomes unproductive, it is written off as a loss in the year incurred.

The working interest that is created is an interest in minerals in place which is burdened with the rights and costs of development of the property, while the royalty interest is an economic interest without these burdens and rights. All other economic interests in the property are taken from the working interest or the royalty interest. A shifting of responsibility for development of the property from the working interest owner to an assignee is known as a farm-out. Generally the party who originally had the working interest retains an overriding royalty, which is an economic interest in the minerals without the burden of development of the lease.

Another type of interest created from a working interest is a net profits interest. This interest entitles the owner to a percentage of the net income, but not of the losses, from the property. It must not, however, be a contractual agreement to pay a certain sum of money on a periodic basis regardless of production; if this were the nature of the contract, the owner of the interest would not be deemed to have an economic interest in minerals and would not be allowed depletion.

The last common types of economic interests are production payments and limited working interests. A production payment is carved out of the working interest and is similar to an overriding royalty, except that it gives the owner the right to a percentage of production for either a specified length of time or until a specific amount of money has been paid. It is a common arrangement when there is uncertainty concerning the value of the reservoir, and thus of the overriding royalty. A production payment is generally not considered to be an economic interest except in the case where the proceeds are pledged to further development of the property.

A limited working interest is a working interest which will cease prior to exhaustion of the revenue, upon reaching a specified total production or specific time limit. It, like a production payment, is utilized when the reservoir size is unknown and the leasing party wants to limit the return to the drilling party. A limited working interest is considered to be an economic interest subject to depletion.

The act of creation of various property interests can be classified for federal income tax purposes into four types, each with different tax implications: leases or subleases, sales or exchanges, anticipations of income, and sharing arrangements. Income derived from a sale or exchange would generally constitute a capital gain, taxable at the lower capital gains rate. Cash or property received in consideration of a lease qualifies as a lease bonus, which is ordinary income subject to depletion. Anticipation of income has the effect of moving ordinary taxable income from a future to a present period. A sharing arrangement involving no cash consideration is not a taxable transaction, and no gain is recognized from this transaction.

A transaction will be classified a lease or sublease in any case where the owner of the operating rights assigns all or a portion of these rights to another person, retaining a continuing but non-operating interaction in production. Thus if the owner of a working interest assigns this interest and retains an overriding royalty, the transaction is a sublease.

TABLE 5-7
TRANSACTIONS CONSTITUTING SALES OR EXCHANGES
(Fractions indicate share of gross production)

Property Owned Before Conveyance	Property Retained	Property Conveyed
1. Minerals (8/8 of 8/8)	(a) Minerals (5/8 of 8/8) (b) Working interest (7/8 of 8/8) (c) Carried working interest, nonperpetual (no production until payout, then 3/8 of 7/8) (d) Production payment (first \$50,000 out of 1/8 of 8/8)* (e) Any combination of minerals, working interest, nonperpetual carried interest, and produc- tion payment	(a) Minerals (3/8 of 8/8) (b) Royalty (1/8 of 8/8) (c) Royalty (1/8 of 8/8) and working interest (8/8 of 7/8) until payout, then 5/8 of 7/8) (d) Minerals (7/8 of 8/8 until payout of production payment then 8/8 of 8/8) (e) Any continuing interest or combination of continuing interests
2. Royalty (1/8 of 8/8)	(a) Royalty (3/32 of 8/8) (b) Production payment (first \$50,000 out of 1/8 of 8/8)*	(a) Royalty (1/32 to 8/8) (b) Royalty (no production until payout of production payment, then 1/8 of 8/8)
3. Working interest (7/8 of 8/8)	(a) Working interest (6/8 of 7/8) (b) Carried working interest, nonperpetual (no production until payout, then 4/8 of 7/8) (c) Working interest (8/8 of 7/8 until payout, then 4/8 of 7/8) (d) Production payment (first \$50,000 out of 3/8 of 7/8)* (e) Any combination of working interest, nonperpetual carried working interest, and produc- tion payment*	(a) Working interest (2/8 of 7/8) or overriding royalty (2/8 of 7/8) (b) Working interest (8/8 of 7/8 until payout, then 4/8 of 7/8) (c) Carried working interest, nonperpetual (no production until payout, then 4/8 of 7/8) (d) Working interest (5/8 of 7/8 until payout of production payment, then 8/8 of 7/8) (e) Any continuing interest or combination of continuing interest
4. Overriding royalty (1/8 of 7/8)	(a) Overriding royalty (1/16 of 7/8) (b) Production payment (first \$50,000 out of 3/32 of 7/8)*	(a) Overriding royalty (1/16 of 7/8) (b) Overriding royalty (1/32 of 7/8) until payout of production payment, then 1/8 of 7/8)
5. Net profits interest (30% of net profits)	(a) Net profits interest (10% of net profits) (b) Production payment (first \$50,000 out of 25% of net profits)*	(a) Net profits interest (20% of net profits) (b) Net profits interest (5% of net profits until payout of production payment, then 30% of net profits)
6. Production payment (first \$50,000 out of 1/8 of 7/8)	Production payment (first \$30,000 out of 3/40 of 7/8)*	Production payment (first \$20,000 of 2/40 of 7/8)
7. Any property interest	Nothing	Entire property interest

*After August 6, 1969, the retained payment would be treated as a mortgage loan on the property conveyed, and the seller would keep in economic interest retaining the production payment.

Source: Clark Breeding, Frank Burke, Jr., and A. Gordon Burton, Income Taxation of Natural Resources (Englewood Cliffs, New Jersey: Prentice-Hall, Inc., 1977) p.502.

A sale or exchange involves either transferring all of the taxpayer's interest, or a fraction of the interest which is identical as to type to what he retains. Examples would be the owner of a working interest selling one half of his interest, or the owner of a royalty interest selling 25 percent of his interest. The retention of the working interest and assigning of a continuous non-operating interest is also viewed as a sale. Examples of transactions constituting sales are given in Table 5-7.

A sharing arrangement is said to result when the grantor conveys some interest in the minerals in return for aid in the development of the property, rather than in exchange for cash or equivalent consideration. Only if the property is "proven" at the time of the transaction, so that the net costs and benefits can be assessed, can the transaction lead to a taxable exchange.

The tax treatment of income from a sale is similar to sales of other property used in a trade or business. Gain is recognized to the extent that the sales price exceeds the basis of the property, where this basis is reduced by accumulated depletion allowances and does not include intangible drilling costs which have been expensed. Except in the case of a dealer in mineral properties, the gain is taxed at the lower capital gains rate.

E.3(f) Organizational Forms and Taxation. The types of property interests described in the previous pages arise because of the inability or unwillingness of the owner of mineral rights or his assignees to individually bear the entire burden of development of the property. This is because of two factors: the heavy investment required at all stages of the operation, and the high level of risk inherent in the industry. Whether risks are comprised of the uncertainties surrounding the quantity and quality of reserves in the initial phases of development, or the uncertainties pertaining to costs, prices, regulation, and taxation in the production period, they result in a much wider dispersion of expected returns than is normal in other industries. The solution to this problem is a division of costs and risks resulting in the creation of the various types of property interests described above.

All of these property interests involve joint ownership of the mineral interest. A joint operation may be conducted under any one of the following forms of business organization: co-ownership, joint venture, partnership, trust, or corporation. A major tax consequence arises when an association of owners becomes a corporation, and as such a separate taxable entity--income from the property will be subject to the corporate income tax before distribution to the participants. Moreover, tax benefits such as intangible drilling rights and depletion are not available to corporate stockholders, but only to the corporate entity itself. For a partnership, which is not directly taxable, these benefits can be claimed in the individual tax returns of the partners [103].

The Internal Revenue Code enumerates six characteristics which distinguish a corporation from other forms of organizations: (1) associates; (2) an objective to carry on a business and divide the gains; (3) continuity of life; (4) centralization of management; (5) liability for corporate debts limited to corporate property; and (6) free transferability of interests [104]. If an association has those characteristics it is taxed as a corporation despite its nominal status.

A common form of investment in oil and gas properties is a limited partnership. A limited partnership is a partnership which is comprised of two classes of partners, general partners and limited partners. The general partner is personally liable for the debts of the partnership (hence the association is not a corporation by characteristic (5) above), but the limited partners are only liable for partnership debts up to the amount which they have invested.

Limited partnerships in oil and gas ventures have until recently enjoyed the status of a "tax shelter" for investors with income unrelated to oil and gas production. The limited partner, upon joining the partnership, assumed a "contingent liability" for a part of the partnership debts, although his limited partner status insured him against ever having to come up with this money. The contingent capital liability assumed was written off as a loss on the limited partner's individual tax return in the year incurred. A small dollar investment, therefore, could lead to a large tax loss to offset other income, and hence a tax savings exceeding the actual amount of money invested. The Tax Reform Act of 1976 [105] eliminated the obvious inequities resulting from this legal arrangement by limiting the amount claimed as a loss to the amount of money the taxpayer has contributed to the partnership. This will have the effect of drying up one of the sources of outside money for the oil and gas industry, and particularly for those ventures with a high degree of risk.

Despite recent statutory changes, the manipulation of organizational forms to accommodate federal income taxation rules will continue to be very important in the oil and gas business. This can be illustrated by the effect of a recent revenue ruling dealing with farm-outs. A normal farm-out, as previously discussed, was viewed by the parties as a lease. No gain or loss was recognized on the transaction. Revenue Ruling 77-176 held that if the working interest party (sublessee) received acreage outside the drilling site, the value of this acreage should be included in his gross income and taxed as a sale. A noted accountant in oil and gas taxation enumerated four methods to circumvent this ruling, two of which consisted of creating a partnership; transfer of property (in this case acreage outside the drilling site) to a partnership does not constitute a taxable transaction [106].

F. GAS INDUSTRY FINANCE

Now and for the foreseeable future, the primary financial concern of all segments of the natural gas industry is the acquisition of capital; though the industry hopes to use much of this capital to expand gas supply capability, it will be forced for the first time to allocate large amounts of the capital to maintenance of existing capability. Acquisition of capital is not, of course, a new concern for the industry, but dwindling gas supplies, high general inflation rates, and inconsistent government regulatory policies have raised this concern to new heights in recent years. This section explains how each of the three industry sectors has historically raised capital and discusses the problems of continued use of these methods.

The first part, F.1, of this section is a background explanation of what corporate revenue account statements and balance sheets are, of the theory by which "cost of capital" is conventionally analyzed, and of general considerations relevant to debt financing; laymen in the field of corporate finance will find this part helpful. Parts F.2 and F.3 discuss financial considerations peculiar to, respectively, the gas production sector and the gas utility (transmission and distribution) sectors.

F.1. Background Financial Principles

The traditional first step in analyzing the financial structure of a business is an examination of a statement of its income accounts and its balance sheet.

F.1(a) Income Accounts. The statement of income accounts shows what a business's revenues and non-capital expenses for a particular year were. Typically, the first entry in a statement of income accounts will be for total (or gross) operating revenue. This is revenue earned by the principal operations of the business, an admittedly arbitrary classification which allows separation of revenues from other (or non-operating) sources such as subsidiaries or investments. These other revenues are also reflected in the statement, which may, of course, further partition both classifications to show component sources. Revenues generated by the sale of stock or by borrowing are not reflected on income account statements.

The largest non-capital expense of a business is usually for operation and maintenance. The statement will reflect this as a deduction from total revenue, as it will (a) depreciation, depletion, and other "write-offs" of capital assets, (b) interest expenses, (c) state and federal taxes, and (d) miscellaneous other, often non-recurring, expenses. The remaining revenue is commonly termed "net income" (or profit); it and write-offs, stock and debt issues, and profits from miscellaneous extraordinary asset sales provide the working capital with which the business can make capital purchases, pay dividends, and re-acquire outstanding debt and stock.

F.1(b) Balance Sheet. The balance sheet is a statement of the firm's assets and liabilities as they have been accrued over time. Categories entered on a balance sheet are traditionally defined in such a way that assets and liabilities turn out to be exactly the same and the sheet then "balances". The asset portion of the balance sheet typically includes: (a) current assets, which include such items as cash on hand and inventory; (b) property, plant and equipment, which is typically the largest entry and reflects the capital assets which the company owns; and (c) and "other" assets, which may be further broken down to reflect investments or deferred debits or other assets peculiar to the business of the company.

The liabilities section of the balance sheet will generally reflect: (a) current liabilities, such as notes or loans payable; (b) long-term debt; (c) deferred credits; (d) other reserves; (e) outstanding common and preferred stock; and (f) retained earnings (revenue generated by the business and reinvested in the business).

Examination of the balance sheet for a firm which has been doing business for some time will show that most non-current liabilities may be categorized either as equity or debt. There is a consensus in economic circles that retained earnings and common stock should be treated as equity. Preferred stock has historically been treated as a source of equity financing, but in fact is much more in the nature of debt. This is so because the level of risk to which an investor in preferred stock is exposed is about the level of risk to which an investor in debt securities is exposed. In the event that the company fails and liabilities exceed assets, preferred stock certificates commonly provide that the holders of that stock are returned their investments before the holders of common stock; state and federal laws similarly provide that the holders of debt instruments are returned their investments before the holders of common or preferred stock.

F.1(c) Cost of Capital. The "cost of capital" theoretically influences the sources to which corporate management might turn for funds. Conventional wisdom holds that debt financing entails the least cost to the corporation. This is so because corporate revenues which go to pay interest on debt are not subject to federal income taxation; too, the holder of a debt instrument is exposed to lower risk of non-repayment than are other investors and therefore should be content to receive a lower rate of return than other investors.

Preferred stock financing entails the next least expense to the corporation. It is more expensive than debt because the premiums (dividends) paid to holders of preferred stock do not receive the tax exemption extended to interest payments. However, because the holder of preferred stock receives payment ahead of other equity holders in the event the company fails and has first call on dividends in better times, the rate of return expected by the preferred stock holder is very similar to that expected by the holder of a debt instrument.

Corporate financing by common stock issue is more costly than debt or preferred stock financing. Not only do common stock dividends not receive special tax treatment but also stockholders are exposed to significant risk of loss in the event of corporate failure or poor performance and, therefore, expect greater rates of return than do holders of preferred stock or long-term debt. There is a thin consensus that use of retained earnings is the most expensive form of equity financing; the consensus is thin because economists have yet to agree on the best method by which to determine the cost of capital which is internally generated. The theory is that financing with internally generated funds is the most expensive financing course principally because those funds may be called on at any moment, regardless of fluctuations in stock or bond markets, and may be called on for projects which entail high risks or for which the risks are uncertain.

F.1(d) Debt Financing. Several aspects about debt financing should be borne in mind. First, balance sheets and statements of income accounts reflect only long-term debt denoted as such; short-term debt is subsumed under other headings. Particularly as to the balance sheet, this is a reasonable treatment because the general business practice is to repay short-term debt quickly or to refinance it (roll it over) as part of a larger, long term, debt package.

Long-term debt is generally evidenced by either general obligation debentures or mortgage bonds. The significant distinction is that a mortgage bond creates in its holder a lien against some particular asset of the firm, while a general obligation debenture creates in its holder an uncollateralized claim against all the assets of the corporation. Bonds are considered the more secure of the two types of debt. Either bonds or debentures, but more commonly debentures, are issued subject to indentures. Indentures are restrictive agreements entered into by the corporation which place limits on the corporation's authority to issue future debt; the obvious function of an indenture is to protect the bond or debenture holder from future management decisions which might undermine the quality of a currently prudent investment. Indentures usually do not restrict issuance of "junior debt," that is, debt securities which subject their holders to less financial security than that enjoyed by holders of other debt. A second mortgage is probably the most familiar example of junior debt.

It is not generally considered prudent to finance very risky projects with debt capital; this is so because (1) investors, if available at all, are likely to exact a higher than normal rate of return for the use of their capital on such projects and (2) project failure can leave the company in a position of not having expected project revenues but being, nonetheless, legally obligated to repay the principal borrowed and also the interest agreed upon. In this position, the firm can experience "poor cash flow" in that available revenues must be allocated more and more not to the business of business, but to servicing non-productive debt.

Finally, each debt financing effort has at least a slight negative impact on the cost of future debt financing efforts because bond rating services, such as Moody's or Standard and Poor's, consider the size of existing debt service requirements and the ratio of total debt to total capitalization in determining the appropriate rating to assign to a bond issue. Each level down the rating hierarchy from Aaa carries with it a higher investor expectation regarding rate of return. Some institutional investors, such as pension funds and insurance companies, have large amounts of money to invest and are prohibited by law from investing in debt securities rated lower than A [107].

F.2 Production Company Finance

F.2(a) Data Limitations. Financial information on domestic gas production companies is extremely hard to find. The explanation which follows is based primarily on a series of annual publications by the Chase Manhattan Bank entitled, Financial Analysis of a Group of Petroleum Companies [108]. The Chase analyses are highly reliable, but not without problems for current purposes. Because gas producers are in fact oil and gas producers, financial analyses of gas producers cannot be developed apart from the refining, marketing and crude oil activities which also enter the bundle of business for which producers must raise capital. Although a financial analysis of gas production activities alone might initially seem more appropriate for purposes of this examination, such an analysis would be unrealistic and unreliable because the allocations gas producers make of the resources at their disposal are in fact shaped by the whole spectrum of options and restrictions endemic to the oil and gas business. Therefore, the following explanation does not attempt to segregate gas production finance from the firms' overall financial structures.

Another aspect of the Chase analyses is that they deal with energy producers who have both foreign and domestic operations. This is because the major energy producers are multi-national corporations. Again, the practical problem is that division of multi-national business into domestic and foreign components is extremely difficult, and somewhat artificial. The Chase analyses do, however, provide some separate treatment of foreign and domestic revenues, such as those demonstrated in Figures 5-4 and 5-5. The following examination also attempts separate treatment of domestic activities whenever that is practical.

Figure 5-4 demonstrates that the percentage of after tax net income of the firms in the Chase Group which may be attributed to U.S. operations has fluctuated somewhat over the past 13 years, particularly during the period immediately following the Arab oil embargo, but has generally represented approximately 55% of all net income. Figure 5-5 reflects that US capital expenditures as a percentage of worldwide capital expenditures for the Chase Group have generally been in the neighborhood of 60%.

The following analysis assumes that world-wide capitalization ratios fairly represent capitalization ratios for the domestic market alone; authorities in the natural gas industry believe this assumption is valid [109] and reliable data is just not practically available to proceed with a financial analysis of the domestic activities of multi-national oil companies absent this assumption.

The Chase Group currently consists of 27 multi-national oil companies. In the United States there are thought to be as many as 10,000 gas producers [110]. Industry authorities feel that if one describes the domestic activities of the Chase Group, then one has described 75% of the total US oil and gas production industry [111]. This is a convenient rule of thumb which is not subject to disproof for the same reason that it is convenient; there are no statistics to rebut it. Independent oil and gas producers, if they report at all, do not report their financial dealings in the same detail as do large corporations. This examination makes no effort to describe problems which might be peculiar to independent oil and gas producers.

Source: The Chase Manhattan Bank, Financial Analysis of a Group of Petroleum Companies, The Energy Economics Division (1 Chase Manhattan Plaza, NYC: The Chase Manhattan Bank, 1976, 1977).

Figure 5-4: PERCENT OF WORLD-WIDE AFTER TAX NET INCOME OF CHASE GROUP FIRMS WHICH MAY BE ATTRIBUTED TO U.S. OPERATIONS

Source: Chase Financial Analyses, 1976, 1977

Figure 5-5: PERCENT OF WORLD-WIDE CHASE GROUP CAPITAL EXPENDITURES WHICH MAY BE ATTRIBUTED TO U.S. OPERATIONS

F.2(b) Capitalization. At the core of financial concerns of oil and gas producers over the next fifteen years will be the generation of capital necessary to explore for and develop new sources of oil and natural gas. The growth in demand for capital is expected to be severe throughout the domestic economy, but is truly unprecedented in dimension in the oil and gas industry. Figure 5-6 shows the growth pattern in capital expenditures for the past 13 years of the firms covered by the Chase analysis. As subsequent paragraphs will explain, the curve of Figure 5-6 is expected to continue a dramatic upward course for the foreseeable future.

Source: Chase Financial Analyses, 1976 1977

Figure 5-6: CHASE GROUP WORLD-WIDE CAPITAL
EXPENDITURES IN NOMINAL DOLLARS (MILLIONS)

Traditionally, large oil and gas firms have purchased capital assets and repaid their investors mostly through internally generated capital. This internally generated capital has been almost exclusively either net income or write-offs. The monies which have not been generated internally have been raised through the issuance of long-term debt or the sale of common or preferred stock. Figure 5-7 shows that the percentage of working capital generated through net income and write-offs has been declining rather steadily for the past 13 years. Its current level, 69% in 1977, is up slightly from its 1976 record low of 67%. This prolonged decline in the relative role of internal funding is viewed with concern by the financial community because internally generated funds are the funds of preference for high-risk projects such as oil and gas exploration.

To understand why internally generated funds have not kept pace with the requirements of capital expenditures one should look at the two primary components of internally generated funds, write-offs and net income. Write-offs, to a gross approximation, are tied to the net capital assets of the industry (which are being gradually "written off"). Capital expenditures on the other hand are driven by the demands of the market place and do not bear, at least in times of expansion or recession, a close correlation to net capital assets already in place. The result is that during times of expansion capital expenditures will likely rise at a rate faster than accumulated net capital assets and, hence, faster than write-offs. Figure 5-8 demonstrates this phenomenon over the past 13 years for the firms in the Chase Group. Note particularly that during the last 4 years the percentage of write-offs to net capital assets has remained around the historical level of 10%-11% while the ratio of capital expenditures to net capital assets has averaged 24%, or 1.33 times its pre-1974 average of 18%.

How it happens that the other primary component of internally generated capital, net income, has not risen sufficiently to offset the loss in the write-off component is not as clearly demonstrated. Net income is what is left of gross revenues after operating costs, interest expenses, taxes, write-offs and other deductions have been

Source: Chase Financial Analyses, 1976, 1977

Figure 5-7: CHASE GROUP WORLD-WIDE PERCENT OF
WORKING CAPITAL GENERATED INTERNALLY

subtracted. Thus, net income as a percentage of gross income may drop over time for reasons which are, at various times, attributable more to increases in one deduction than to another. Also, the determination of what to include in "operating costs" is very subjective, potentially ranging from paper clips to "commissions" paid to Arab sheiks. In the case of the firms covered by the Chase analyses, operating costs as a percentage of gross income first dropped, then rose, during the past 13-year period; during this same period direct taxes were rising during the time costs of business were decreasing, and were falling during the time costs of business were rising.

Source: Chase Financial Analyses, 1976, 1977

Figure 5-8: CHASE GROUP WORLD-WIDE CAPITAL EXPENDITURES AND
WRITE-OFFS AS A PERCENT OF NET CAPITAL ASSETS

Source: Chase Financial Analyses, 1976, 1977

Figure 5-9: CHASE GROUP WORLD-WIDE NET INCOME AS A
PERCENT OF GROSS WORLDWIDE REVENUES

The net result of this has been, however, that net income as a percentage of gross revenues has been getting progressively smaller in the past 13 years. Figure 5-9 demonstrates the fall of net income as a percentage of gross revenue from approximately 9-1/2% in 1965 to only 4-1/2% in 1977; the figure reflects that the share of the gross revenue pie allocated to net income (profits) has been cut in half in the past 13 years. Because of this, net income has only been able to grow 182% during the same period (1965-1977) in which capital expenditures have grown 250%.

As the amount of money for capital asset acquisition and repayment of investors generated internally has decreased over the past decade, debt financing has taken up the slack. (The absolute level of common and preferred stock financing has remained about the same, which means that as a percentage of overall capitalization these two sources have played a progressively less significant role). As demonstrated by Figure 5-10, the percentage of total capital employed which is comprised of long-term debt has risen dramatically from 13% in 1960 to almost 26% in 1977, an increase of 100%.

Source: Chase Financial Analyses, 1976, 1977

Figure 5-10: CHASE GROUP WORLD-WIDE LONG-TERM
DEBT AS A PERCENT OF TOTAL CAPITALIZATION

A 26% debt/capitalization ratio is considered by authorities in the oil and gas industry to be very near the maximum which investors will tolerate in such a high-risk business [112]. Along these lines it is worth noting that some obligations, such as long-term production payments (repayments of cash contributions from future production), which should logically be treated as long-term debt, are not so treated by traditional accounting definitions.

The level of long-term debt within the oil and gas industry does not appear likely to decrease in the near future. Though the level of capital outlays will continue to rise, it does not appear that the industry will be able to generate much more money internally in the future than it has in the recent past. This conclusion is based largely on the premise that costs of doing business (including interest costs but excluding premiums, all taxes, and write-offs) will follow the current trend and remain greater than the rate of increase in gross revenue; in the four post-embargo years of 1974-1977, costs of doing business rose 41% while gross income rose only 30% [113]. Even should taxes, as a percentage of gross revenue, continue the very gradual decline which began in 1975, the relative size of net income is unlikely to increase in light of increased interest and other operating expenses.* On the more encouraging side, the absolute size of write-offs will continue to increase as the net capital assets of the industry increase and revenue from the sale of natural gas should rise fairly steadily in response to the US phased decontrol of most gas prices; recently revenue from the sale of natural gas has represented only about 3-1/2% of the gross revenue of the Chase Group, although natural gas has represented about 20% of the total energy the group sells [114]. Currently contemplated decontrol of domestic crude oil prices could provide large infusions of working capital, depending on how that decontrol and federal tax increases are coordinated.

F.2(c) Capital Requirements Projections. Even should revenue begin to rise significantly faster than expenses and taxes, the rate of increase in capital expenditures is expected to be so great that internally generated revenue will simply not be sufficient to meet even its current 69% share of the funds from which capital purchases and investor repayment are made. Because of the national debate over US energy policy, there have been numerous projections made of the amount of capital to be required by domestic oil and gas exploration and production companies over the next 10 to 15 years. The figure arrived at by the National Gas Survey (1978) was 480 billion 1975 dollars [115]; this would amount to \$758 billion over the fifteen-year period if one assumed a 5% per year inflation rate. These figures are generally compatible with those developed by the Chase Bank, several private consulting firms, and a number of the large energy producers themselves [116]. The significance of raising \$480 billion over a fifteen-year period is demonstrated by the fact that this would correspond to approximately seven times the gross investment in fixed assets which the domestic oil and gas industry has accumulated for exploration and production purposes since the industry was born.**

Such high projected capital investment needs can be largely explained because of higher than average inflation rates in the oil and gas industry and the increased finding costs associated with exploration and development of oil and gas deposits which are located in increasingly hostile environments. Though it hardly seems possible, Figure 5-11 demonstrates that inflation in the oil and gas industry has been significantly higher in the past decade than it has been in the economy in general; the National Gas Survey (1978) forecasts that inflation in the oil and gas industry will run approximately 150% of the nation-wide inflation rate for the next decade [117]. As an easily grasped example of the impact of the inflation rate reflected in Figure 5-11, consider that a 1000 horsepower on-shore drilling rig--the type needed to drill in the 8,000-12,000 foot range--sold for \$700,000 or \$800,000 back in 1968 but in 1978 cost between \$1-1/2 and \$2 million [118].

* As this section is being edited, the major oil producers are reporting second profits. A comparison of the increases in profits relative to increases in capital expenditures is not yet available, however.

**The multiplier of seven is somewhat deceptive in that gross domestic production assets were, many of them, purchased at some time in the past when the value of a dollar was significantly higher than it was in 1975, so that the replacement cost of the gross investment would actually be much, much higher and the multiplier, therefore, lower. Also, this multiplier was developed by relying on Chase's figure for the domestic investment in fixed assets for production. The Chase figure was then divided by .75 to approximate the entire US industry investment.

Source: Independent Petroleum Association of America,
United States Petroleum Statistics 1979 (Revised)
 (1101 Sixteenth Street, N.W., Washington, D.C.:
 I.P.A.A., 1979)

Figure 5-11: OIL AND GAS INDUSTRY INFLATION RATE

Increased finding costs, the second element mentioned as a prime factor for the unprecedented size of upcoming capital expenditures in the industry, has many ramifications which are also inflationary. As a conceptual matter, however, this phenomenon makes more intuitive sense. Essentially, it arises because the easily found and developed oil and gas resources in the United States have largely been found and developed. This leaves resources which are located off-shore or which are located at great depth or in extremely cold environments. Offshore rigs are more expensive than onshore rigs by a factor of 5 or 6 and if, on an average for onshore wells, it costs \$50 per foot to drill at 8500 feet, it will cost \$115 per foot to drill at twice that depth [119]. Also, when drilling offshore, oil and gas producers are required to pay much higher lease bonuses and much higher royalty rates to the federal government than they would were they drilling onshore [120]; one commentator estimates (probably, overestimates) that 34% of the capital requirements of the domestic oil and gas industry over the next 10 years can be attributed to the size of offshore lease bonuses [121].

The Technical Advisory Committee on Finance for the Natural Gas Survey (1978) applied a 1974 Ford Foundation energy industry finance model to estimate how, if at all, the necessary capital purchases of the domestic oil and gas industry can be financed if the financial structure of the industry is not to be radically reworked. They assumed that over the fifteen year period from 1975 to 1990 the percentage of total producer capitalization which was represented by long-term debt would not exceed 25% and that the overall return on investment would average 10.3%. If these two parameters are in fact held at the level the committee prescribed for them, then the analysis reveals that the oil and gas industry will be forced to turn to the equity markets for an ever-increasing percentage of their capital requirements. More specifically, the analysis revealed that the oil and gas industry will have to occupy, on an average, 6.8% of the domestic corporate equity market; this would represent an increase of three-fold over its current estimated average share of that market, 1.7% [122]. In an era when all elements of the domestic industrial structure may be expected to experience a capital shortage, it should not be a foregone conclusion that the oil and gas production sector will be able to quadruple its share of the equity market.

The Technical Advisory Committee was careful to point out that its projections were based on a number of less than optimum parameters, for example, the \$480 billion total capital amount and the 25% debt capitalization ceiling. Were these or other parameters loosened, then it might be possible for the oil and gas industry to meet its production goals without cornering such a significantly larger portion of the equity market.

The total capital need projected for the next fifteen years appears to be, if anything conservative. The debt-to-total-capitalization ratio is certainly higher than historic, but may not in fact be as high as debt investors will allow that ratio to climb; especially after years of high inflation, debt investors may come to accept a higher level of risk in order to receive a needed higher rate of return. Note, however, that increased debt capitalization would increase the interest burden which the oil and gas producers would bear and thus undermine their ability to generate capital internally; their bond ratings, currently mostly triple or double A, would also be expected to fall.

The area in which the Advisory Committee's projections are most probably too pessimistic is that of return on total invested capital. The 10.3% figure selected for the model represented the average in times prior to 1973. Since 1973, the Chase Group's return on all domestic investment has been running significantly higher than 10.3%. The 1977 figure was 14.2%; the average return on domestic investment for the 1974-1977 period was a bit above 14% [123]. These higher rates of return are now much more competitive with rates of return available in American manufacturing industries (where risk is presumably lower) and should be a significant help to the production sector in attracting equity investment. Moreover, an increased return on total investment makes possible the meeting of the dividend expectations of equity investors while at the same time offsetting, at least in part, increased debt financing with increased use of retained earnings. Table 5-8 reflects the recent histories of return on domestic investment for oil and gas industry firms and for manufacturing firms in general.

From all that has gone before concerning the financial structure and operation of oil and gas production firms, one can see that they are entering an era of unprecedented demand for capital in a debt posture which is less desirable than has historically been the case. However, their continuing ability to generate relatively significant amounts of capital internally and the likelihood, not yet a certainty, that government regulatory policies will allow them to earn a rather high rate of return on invested capital give the producers a reasonable chance of attracting the capital necessary to meet the market's future energy demands.

TABLE 5-8
RATES OF RETURN

Year	Oil and Gas Industry Rate of Return on Average Domestic Capital Investment ¹	All Manufacturing Industries Rate of Return on Average Domestic Capital Investment ²
1965	11.2	13.0
1966	12.3	13.4
1967	12.6	11.7
1968	12.3	12.1
1969	10.9	11.5
1970	9.9	9.3
1971	9.3	9.7
1972	9.6	10.6
1973	10.5	13.6
1974	14.6	14.9
1975	12.9	11.6
1976	15.2	13.9
1977	14.2	14.2

Sources: ¹Chase Financial Analyses, 1976, 1977

²IPAA US Petroleum Statistics 1979 (Revised)

F.3. Gas Utility Company Finance

F.3(a) Data Limitations. Financial analyses of the gas transmission and distribution sectors of the overall gas industry usually focus on the "gas utilities"; that is, the finances of distribution companies and transmission companies are examined in the aggregate. With some exceptions, the explanation which follows is structured along similar lines. The principal reason for this structuring is that the gas transmission and distribution sectors are still in a period of sweeping change (ultimately attributable to declining gas reserves) and, therefore, there is a premium on the currency of financial statistics; current statistics which detail the gas distribution sector apart from the gas transmission sector are not practically available. The other important reason for this structuring is that projections have been made of the future capital needs of the entire gas utility industry and future capital is the key concern for both sectors.

The American Gas Association's annual statistical publication, Gas Facts [124], presents gas utility company data on four categories of utilities: distribution companies, transmission companies, integrated companies, and combination companies. As a practical matter, a company is classified as:

- 1) a distribution company if it receives at least 95% of its gross revenues from the sales of gas to ultimate customers;
- 2) a transmission company if it receives 95% of its gross revenues from the transportation of gas for others, the sale of gas for resale, or mainline sales to direct customers;
- 3) an integrated company if it owes significant parts of its gross revenues to both distribution and transmission activities; and
- 4) a combination company if it supplies both gas and some other utility service, such as electricity.

As Table 5-9 reflects, transmission companies currently account for approximately 40% of the total operating revenue of the gas utility industry, and distribution, integrated, and the gas delivery functions of combination companies each account for approximately 20%. Table 5-9 reflects a similar ordering of the entire gas utility industry if one focuses on current percentages of net gas plant.

TABLE 5-9
MEASURES OF GAS UTILITY INDUSTRY COMPOSITION

Company Type	1977 Gross Revenues (Millions)	% of Industry Total	1977 Net Gas Plant (Millions)	% of Industry Total
Distribution	8,705	18.8	6,688	19.4
Transmission	19,836	42.8	12,678	36.8
Integrated	9,800	21.2	7,790	22.6
Combination	7,968	17.2	7,278	21.1

Source: Gas Facts, 1977

To a reasonable approximation, one can develop statistics for the distribution sector of the gas utility industry by summing those of the distribution companies, those of the gas portion of the combination companies, and 60% of those of the integrated companies; the 60% figure derives ultimately from the assumption that revenues and expenses of combination utilities may be apportioned to gas distribution in the same ratio that the companies' aggregate net gas distribution plant bears to the companies' total utility plant.* This approximation is made (and noted) occasionally in the examination which follows, but is considered too imprecise to support all analyses.

*The AGA made this assumption in its development of distribution utility finance characteristics for the National Gas Survey (1978). The difference between the Gas Facts sum for the three sector parts (i.e., distribution, gas portion of combination, and integrated companies') and the National Gas Survey (1978) figure for the same years is approximately 40% of the Gas Facts integrated company figure.

The gas distribution sector of the gas utility industry was analyzed most recently by the AGA for the Technical Advisory Committee on Finance for the National Gas Survey (1978) [125]. The AGA study presented there is current through 1975. The FERC publishes annual statistics which cover major interstate gas pipeline companies [126]. The FERC statistics provide essentially complete coverage of trends in the transmission sector, but, principally because of definitional differences, cannot be readily related to the AGA Gas Facts statistics. The paragraphs which follow normally rely on the FERC statistics to describe the transmission sector, where that sector is described apart from the entire gas utility industry.

Finally, the AGA's analysis of the gas distribution sector revealed that the statistics for the distribution sector as a whole rarely represented very accurately the financial posture of any one gas distributor [127]; this is apparently so because of the widely varying regulatory policies of the state and local agencies under which the gas distributors work.

F.3(b) Capitalization. The chief financial concern of the gas utility industry is the raising of unprecedented amounts of capital to finance rather small incremental additions to gas supply. Though some of these gas additions will allow for market expansion, most will be required simply to maintain supply to current markets. The capital will increasingly be applied not only to the traditional business of gas utilities, the construction of gas transmission and distribution plant, but also to the financing of gas production, both natural and synthetic, and to gas storage. To understand how the gas utility industry will most likely deal with its chief financial concern, the financial structure of the industry as it has evolved to date is important.

The gas utility industry is characterized as "capital intensive"; that is, a relatively large capital investment is required to generate each dollar of revenue. As of 1977, the gas utility industry had \$.70 invested in net plant for each dollar of gross revenues and \$9.50 invested for each dollar of net operating income earned [128]. As Figure 5-12 shows, both these indicators, though still very high, are lower than they have ever before been.

Source: Gas Facts, 1977, 1974, 1972

*Note: Net operating income is calculated before payment of interest on long-term debt.

Figure 5-12: INDICATORS OF GAS UTILITY
INDUSTRY CAPITAL INTENSITY

This progressive lessening of capital intensiveness may be attributed to (1) the "mature" stage of an industry in which economies of scale are real, (2) the increased market value of all energy forms which became evident in the early 1970's, and (3) the near-moratorium on new gas service commitments which has existed since 1973. Through 1977, the investor-owned gas utility industry had invested approximately \$55 million in gross plant, of which \$34.5 million represents the undepreciated net plant. Approximately 55% of the net plant figure may be allocated to the gas distribution sector and 45% may be allocated to the gas transmission sector of the industry [129].

As might be expected, the gas utility industry has historically been debt heavy. Long term, generally twenty-year, bonds and debentures were until the 1970's easily issued at the low interest rates one would expect when dealing with essentially risk-free investments. As Figures 5-13, 5-14, and 5-15 reflect, 1976 and 1977 were the first years in recent history that either sector or the gas utility industry as a whole exhibited less than 50% debt capitalization.

The manner of reporting the data from which Figures 5-13 and 5-15 were developed was altered in 1973 pursuant to an FPC-ordered accounting redefinition [130]. This reporting change primarily affects statistics for gas transmission companies. Prior to 1973, a gas utility's investment in a subsidiary, for example, a gas production company, appeared to increase the assets of the gas utility only to the extent that the subsidiary paid dividends to the parent company. Beginning in 1973, the gas utility (parent company) was required to report as its own retained earnings that percentage of the retained earnings of the subsidiary which were allocable to the utility's equity interest in the subsidiary. As a result of this definitional change, the equity capitalization of gas utilities with subsidiaries is higher than it otherwise would be. In addition to this definitional change, the increased equity capitalization trend which is evident for the entire industry from about 1970 on is influenced by (1) the dramatic deceleration of new service commitments during a time of curtailments and restricted new gas supplies and (2) resistance in the investment markets to continued long-term debt financing of a debt-heavy industry whose future, by traditional conservative standards, is clouded.

Source: Gas Facts, 1977, 1974, 1972

Note: See the next paragraph concerning the possible statistical impact of a definitional change.

Figure 5-13: GAS UTILITY INDUSTRY CAPITALIZATION

GAS DISTRIBUTION SECTOR CAPITALIZATION

Source: Through 1975, A.G.A. Analysis for National Gas Survey (1978), p. 120. 1976 and 1977 data estimated from Gas Facts (1977), assuming 58% of integrated company capitalization may be allocated to distribution sector.

Figure 5-14: GAS DISTRIBUTION SECTOR CAPITALIZATION

Source: U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies, Federal Energy Regulatory Commission (Washington, D.C.: US DOE, 1978); and Federal Power Commission, Statistics for Interstate Natural Gas Pipeline Companies (Washington, D.C.: U.S. Superintendent of Documents, 1966), Tables 8.

Note: See the next paragraph concerning the possible statistical impact of a definitional change.

Figure 5-15: GAS TRANSMISSION SECTOR CAPITALIZATION

Until the mid-1970's, long-term debt issues contemplated a twenty to twenty-five year maturities; issues by the gas distribution sector enjoyed somewhat longer periods to maturity than did issues in the gas transmission sector [131]. As might be expected of investors, largely institutional, that were willing to place funds at risk for such long periods of time, they typically demanded indentures which restricted the number of circumstances in which the borrowing firm could issue additional debt in the future. These restrictive indentures (still employed today) varied from firm to firm and from issue to issue within a single firm. Commonly found indenture restrictions included: (1) minimum long-term debt interest coverage ratios; (2) minimum total debt service coverage ratios; (3) maximum permissible debt/total capitalization ratios; and (4) acceleration of payments to debt issue redemption accounts (sinking funds) as gas supply reserve life indices declined. The fourth restriction applies primarily to issues by firms in the transmission sector.

During the past decade, the pretax interest coverage ratio restriction has been the one of most concern to firms in the gas utility industry. This restriction typically prohibits issuance of new long-term debt by a firm whose pre-federal income tax earnings are not at least 2.25 times as great as its interest obligation on long-term debt [132]; as Figure 5-16 reflects, both sectors of the industry came uncomfortably close to this limit during the 1970's.

Though both sectors of the industry now are moving to more favorable interest coverage ratios (for essentially the same reasons mentioned previously for their move to increased equity capitalization), this rise is generating less than proportional industry confidence on the part of many financial analysts. This is primarily because of the realization that (1) the 2.25 multiplier may be imprudently low in light of the industry's recently clouded future and (2) ratios which do not consider other debt service, which was approximately 15% of the total debt service of the industry during the mid-1970's [133], but which do include as earnings unappropriated undistributed subsidiary earnings (which may in fact be unavailable for debt repayment) provide too unsophisticated a measure of fiscal integrity.

- Source: 1. Transmission Companies - U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies, Federal Energy Regulatory Commission (Washington, D.C.: US DOE, 1978); and Federal Power Commission, Statistics for Interstate Natural Gas Pipeline Companies (Washington, D.C.: U.S. Superintendent of Documents, 1966), Tables 8.
2. Distribution Companies - Through 1975, A.G.A. Analysis for National Gas Survey (1978), p. 120. 1976 and 1977 data estimated from Gas Facts (1977), assuming 58% of integrated company capitalization may be allocated to distribution sector.

Figure 5-16: GAS UTILITY PRE-TAX INTEREST COVERAGE RATIOS

The gas transmission sector has also been particularly hard hit by restrictive indentures which call for acceleration of payments to issue redemption accounts as reserve life indices decrease. Historically, these payments were financed in large part internally through write-offs of depreciable assets. Transmission facilities have in general been depreciated at 3-½% a year [134]. However, because estimated proved gas reserves decreased from a twenty-year supply in 1960 to a 10.7 year supply (including yet unavailable Alaskan gas) in 1977, gas transmission firms were called on to make accelerated payments to issue redemption accounts and they were unable to finance those payments through depreciation alone. The short-fall was generally financed through issuance of the interim short-term debt. Though the short-term debt was eventually accumulated and "rolled over" in less expensive longer term debt issues, it none-the-less added significantly to the overall debt service burden in the industry.

Neither the debt nor equity markets have been particularly receptive to efforts by gas utilities to raise outside capital during the past decade. Bonds and debentures are no longer saleable with twenty-year maturities; eight to ten-year maturities have become more common [135]. Bond rating services, such as Moody's, have downgraded their estimate of gas utility industry long-term debt issues to the point that in some years none will be rated Aaa and more than half will be rated A or lower [136]; this is another indication of the progressively less "safe" nature of these debt investments.

Source: Albert J. Fredman and Radha M. Sharma, "The Performance of Electric and Natural Gas Utility Equities," Public Utilities Fortnightly October 12, 1978: p.22; and Bureau of Labor Statistics, Urban Consumer Price Index (1978).

Figure 5-17: COMPARISON OF AVERAGE ANNUAL COMPOUND RATE OF RETURN ON GAS UTILITY EQUITIES AND INFLATION (for 5 year periods ending with indicated year)

Figure 5-17 reflects rather dramatically why it is that gas utilities have had a difficult time raising capital in the equity markets also. It is based on data from an extensive computerized study [137] undertaken at California State University in Fullerton by Professors Albert Friedman and Radha Sharma. They analyzed the rates of return (dividends plus appreciation in market value) which investors in a portfolio of fifteen natural gas company common stocks realized if they held on to those investments for various numbers of years. As the figure shows, investors who held on to the portfolio stocks for five-year periods and then calculated the average annual compound rate of return on their investments would have discovered that for five of the eleven periods ending between 1966 and 1976 they gained less than the average compound rate of inflation (as reflected by the Consumer Price Index). Equity investments which do not at least stay abreast of the rate of inflation, of course, are not highly sought.

Although it is still too early to make predictions of the longer term fiscal recovery of the natural gas industry, a number of indicators suggest that the industry "bottomed out" around 1975 or shortly thereafter. Pretax interest coverage ratios for both segments of the industry appear to be rising, as do equity capitalization ratios. Regulatory trends seem to be to allow gas utilities higher rates of return on invested capital and more rapid recovery of invested capital through more reasonable ("accelerated") depreciation allowances [138]. Because operating income and write-offs have each increased during each of the past five years (through 1977) while capital expenses have actually remained below their 1973 level, gas utilities have been able to finance more and more of their capital expenditures internally; the 1977 figure was 63.2%, but 53% or 54% more accurately reflects the recent average [139]. These indicators of the improved fiscal condition of the industry should be viewed cautiously because, except for regulatory improvements, each is to some extent influenced by the fact that the gas utility industry has not, by most measures, expanded since 1973.

F.3(c) Capital Requirement Projections. The gas utility industry must be in sound fiscal condition now because it will have to raise truly exceptional amounts of capital between now and 2000. The AGA estimates that the investor-owned industry needs to make \$300 billion (1978 dollars) of capital investment between now and 2000 [140]; this is five times the \$59 billion (1978 book value) which the industry has invested since its inception [141]. Importantly, only about 30% of this new investment is projected to be spent for transmission and distribution of gas in the lower 48 states; this represents a radical shift in the traditional expenditure pattern of the industry and reflects the commitment of the industry to develop secure, if expensive, sources of future gas supply.

Figure 5-18 shows rather dramatically the change which began to sweep through the gas utility industry in the early 1970's and which is expected to accelerate through the end of this century. Industry leaders are well aware that 2/3 of the projected production of natural gas in the year 1990 will have to come from sources which are yet to be discovered or developed [142]. The natural gas utility industry has huge sunk costs (plant in place) at jeopardy, and it cannot afford to depend for its survival solely on the production of natural and synthetic gas by the oil and gas production industry; the gas utility industry is pushing to become more self-reliant in supply, somewhat as it was during the "city gas" days of its infancy. According to the AGA, the utility industry's gas supply expenses through 2000 may be broken down as reflected in Table 5-10. (Traditional functions will require an additional \$88 billion). The Mexican gas component is largely determined by political forces, but will in any event be a small fraction of the overall distribution because nearly all the capital expenses will be borne by the Mexicans.

The consensus opinion within the natural gas utility industry that traditional sources of gas supply will not be adequate to meet the industry's future needs is forcing the industry to abandon its traditional "low-risk", conservative manner of doing business. Obviously, increasing shares of the industry's capital investments will be in traditionally risky ventures, such as deep and offshore exploration for natural gas, or untraditional and as yet unproven production technologies, such as coal gasification. Further, the unprecedented costs associated with securing future gas supplies will tend to force firms in the industry to "place all of their eggs in one basket"; for example, US investment in the Alcan gas pipeline to bring gas from the north slope of Alaska to lower 48 states is projected to cost approximately \$12 billion (1977 dollars) over the next twelve years; this capital expenditure is expected to make possible the transportation of 1.4 trillion cubic feet of gas per year by 1990 [143].

Source: Through 1978: Gas Facts, 1978, Table 149. 1979-2000: American Gas Association, "How Capital Requirements of the U.S. Gas Industry Will Grow," The Oil and Gas Journal May 21, 1979, p. 109.

Figure 5-18: HISTORIC AND PROJECTED CAPITAL EXPENDITURE PATTERNS FOR GAS UTILITIES

TABLE 5-10

ESTIMATED CAPITAL SUPPLY EXPENDITURES BY GAS UTILITY INDUSTRY, 1981-2000

(BILLIONS 1978 DOLLARS)

	1981- 1985	1986- 1990	1991- 2000	TOTAL
COAL GASIFICATION	5.3	13.9	39.5	58.7
EXPLORATION AND DEVELOPMENT	19.5	19.5	39.0	78.0
ALASKAN GAS	9.2	6.1	14.9	30.2
LNG IMPORTS	3.7	1.5	3.6	8.8
MEXICAN GAS	.2	-	-	.2
NEW TECHNOLOGIES	.5	3.5	26.2	30.2
	38.4	44.5	123.2	214.8

SOURCE: American Gas Association, "How Capital Requirements of the U.S. Natural Gas Industry will Grow," The Oil and Gas Journal, May 21, 1979, p. 109.

Although 1.4 trillion cubic feet is a substantial quantity of gas, it represents less than 8% of the natural gas actually consumed in 1977. Twelve billion dollars, on the other hand, represents 35% of the total gas utility industry's 1977 net plant [144]. Costs of marginal supply at these levels will make it very difficult for any one firm within the industry to structure supply plans to avoid large financial exposure on single gas supply projects.

Project financing is emerging as one new means of raising capital for these expensive projects. The lender of project funds for this form of financing is exposed to little risk because the ultimate debtor is not the borrowing utility but, rather, the utility's customers whose bills include an "all events, cost of service tariff" which covers construction costs. Thus, all costs are passed through to the ultimate consumer and the lender provides essentially interim financing only. This form of financing is not favored by the FERC or most state regulatory bodies because it isolates everyone except the ultimate consumer from the risks of project mismanagement or outright failure; probably, the trend will be to allow project financing to cover some percentage of the project costs, thus leaving utility executives with a financial obligation to equity share holders and/or debt investors to see that the projects are designed and managed prudently.

The industry's greater than historic need for capital and the exposure of that capital to much greater than historic risk levels suggest that the industry's current trend to increased equity capitalization must continue, or at least that debt and equity funds must maintain their current balance; debt financing for huge, high-risk projects will be difficult to arrange. Project financing of some sort may be expected to become more common. Regulatory boards will likely allow utilities higher than historic rates of return, more rapid asset depreciation, and more flexibility regarding rate base inclusions--all this in recognition of the numerous and costly uncertainties facing the industry. Although the current financial structure of the gas utility industry really is not such that it should inspire much confidence in the industry's future, pessimism must be discounted as unrealistic in light of the industry's importance to so many aspects of American life.

CHAPTER VI

THE ELECTRIC UTILITY INDUSTRY

A. INTRODUCTION: THE CHANGING ENVIRONMENT

For most of its history, the electric utility industry has operated in one of the most predictable business environments available to any industry in the United States. Granted a regional monopoly over electric output, the utilities could project future demand and capacity requirements based upon population trends and the increasing use of electricity by both households and industry. Demand in most areas of the country increased at an annual growth rate of about seven percent between 1935 and 1973 [1]. This increasing use of electricity was related in part to declining prices in real terms, resulting from economies of scale of larger generating plants and steady though unspectacular technical progress. Potential friction between utilities and regulatory agencies was minimized by low rates and resulting customer satisfaction, so that regulation was primarily concerned with maintaining both adequate capacity to meet demand increases and the financial integrity of the utilities. The choice of fuel in a region was dependent upon relative regional prices, without much consideration of the differential environmental effects of the consumption of various fuels. Finally, of paramount importance for the most capital-intensive industry in the United States [2], (with 19 percent of total business plant investment), inflation was low and plants could be built rapidly, resulting in predictable construction costs. In short, the utilities enjoyed a low-risk business environment which "was inherently forgiving of errors in managerial judgement" [3]. Within this environment both debt and equity of electric utilities were considered secure investments, so that "the raising of capital in equity and debt markets was also a relatively routine procedure" [4].

The major elements of this environment turned sharply against the electric utilities in the early 1970's. Few other industries were quite as vulnerable to a combination of sharply escalating fuel prices, environmental restrictions, and inflation, and certainly few industries faced such mounting pressures to hold the price of their product constant in the face of this radically altered situation. The result was a decline in the average after-tax return on equity from 13.0 percent in the 1967-72 period to 11.8 percent in the 1972-77 period, expressed in current dollars. Were price level adjustments made to these figures, reflecting the higher inflation in 1972-77, the adjusted rates of return would have fallen from 7.8 percent to 4.2 percent between these two periods [5]. Raising capital through debt became costly, and raising capital through equity was in many cases possible only at prices below the book values of outstanding shares. Thus it became increasingly difficult to finance the huge capital expenditures required to serve increasing customer demand, convert to less costly fuels, and protect the environment.

This chapter will explore the effects of these changes upon the electric utility industry, paying particular attention to the Texas and Gulf Coast utilities. Section B will examine the structure, customers, fuel use, regulation, legislation and capital expenditures of the electric utility industry in the United States, and Section C will explore these issues for the Texas and Texas Gulf Coast utilities. In this discussion, primary attention will be focused upon the investor-owned segment of the industry because of its predominance in the Gulf Coast region. Section D will examine the effects of these developments upon the financial position of the electric utilities, and the last section will briefly speculate upon the future environment of the industry.

B. THE ELECTRIC UTILITY INDUSTRY IN THE UNITED STATES

B.1. Industry Structure

The electric utility industry is composed of three major segments: Investor-owned utilities, publicly-owned utilities, and rural electric cooperatives. Investor-owned utilities dominate the industry, with the 200 largest of these owning more than 75 percent of all generating capacity and serving 80 percent of all electric customers [6]. Utilities within the publicly-owned segment of the industry are the property of the federal government or other public bodies such as municipalities, states, and public utility districts. These two sources divide equally about 22 percent of total generating capacity, with cooperatives accounting for the small remaining capacity, although serving 8 percent of the ultimate customers [7]. Many municipally-owned and most rural electric cooperatives do not generate their own power, but buy it in bulk from major utilities.

The structure of the electric utility industry has changed little in past years. There has been a gradual trend toward centralization of the industry, with the number of systems declining from 3578 in 1962 to 3445 in 1968 [8]. Generating units are much larger than previously, giving impetus to this centralization and also to the decrease in the number of utilities generating their own power. Another type of centralization has been provided by an increase in coordinated activities among utilities. The industry has formed nine regional electric reliability councils to coordinate power transfers, in addition to other arrangements for the "pooling" of power. The Electric Reliability Council of Texas (ERCOT) and the resistance of some Texas utilities to interconnection with other power pools will be discussed in Section C.

B.2. Utility Customers and the Structure of Rates

Residential users of electricity constituted 88.7 percent of the total number of customers in 1977, with commercial and industrial establishments accounting for the remainder [9]. These figures, however, grossly underestimate the importance to industry revenues of non-residential customers. Large industrial power users, for example, represent only 0.5 percent of the customers, but generate 28.2 percent of total revenue. Revenue from commercial establishments was 28.8 percent of the total while residential customers generated only 39.4 percent of total revenue [10].

The type of customer which the utility serves is important primarily because of differential patterns of electricity use by various classes of customers, and the effects of these patterns upon the percentage of total generating capacity used at any particular time. A system which serves a larger number of industrial customers, for example, will usually have smaller variations in daily usage.

The capacity factor is important because of its effect upon necessary capacity to meet peak demand. A high capacity factor means less idle capacity, and less idle capacity can mean lower capital investment for any given level of power generation. In addition to daily variations, the overall capacity factor is subject to seasonal, cyclical, and long-term variations. Residential sales, for instance, are more stable through time than industrial sales, being neither as strongly affected by the business cycle nor as amenable to dramatic reductions in power use through improved technology. As a consequence of this, the percentage of residential sales is an important factor in the valuation of utility equity; a higher percentage of residential sales indicates a higher potential capacity factor, causing the price earnings ratio to be higher [11].

The question of rate design--of setting different rates for different types of use--has been subject to a great deal of debate. The general principle behind rate design has been to charge the customer for the cost of the service used, which is ideally the marginal cost of providing that service. However, the determination of marginal cost has proven exceedingly difficult.

Moreover, additional purposes for implementing a system of rate design, as set forth in the Public Utility Regulatory Policies Act of 1978, are to foster conservation and to encourage equitable rates. These principles may or may not correspond to that of marginal cost pricing. This act directs the local regulatory bodies to determine the feasibility of implementing a rate design program consisting of the following: (1) time-of-day rates; (2) seasonal rates; (3) lower rates for interruptible service; (4) no declining block rates (lower rates for greater usage); (5) rates designed to reflect costs of service to each class of customer; and (6) employment of non-price load-management techniques.

B.3. Fuel Costs and Use

The electric utility industry continues to generate the great majority of its power through the consumption of fossil fuels. Table 6-1 presents the generation of electricity by type of fuel during the mid-1970's.

Coal continues to be the predominant fuel in the industry, generating more than 50 percent of output in each of the past six years. Natural gas is declining in importance, and nuclear energy is forming an increasingly important component of generating capacity.

These slow changes in fuel usage do not, however, reflect the dramatic shift in relative fuel prices over the period, because of the long lead times between conception and construction of a generating facility. While the average of all fuel prices have

TABLE 6-1
GENERATION BY FUEL - TOTAL ELECTRIC UTILITY INDUSTRY, 1972-1977
(Kilowatt-Hours in Millions)

Year	Total	Coal (% of Total)	Fuel Oil (% of Total)	Gas (% of Total)	Nuclear (% of Total)
1972	1,475,228	772,871(52.4)	272,530(18.5)	375,735(25.5)	54,092(3.6)
1973	1,582,292	875,707(53.7)	312,805(19.8)	340,449(21.5)	83,334(5.3)
1974	1,562,806	829,842(53.1)	299,306(19.1)	319,931(20.5)	113,727(7.3)
1975	1,614,117	852,972(52.8)	288,873(17.9)	299,766(18.8)	172,506(10.7)
1976	1,750,058	944,562(54.0)	319,779(18.3)	294,810(16.8)	191,107(10.5)
1977	1,899,527	985,443(51.9)	357,879(18.8)	305,353(16.1)	250,882(13.2)

Source: Edison Electrical Institute, Statistical Yearbook for the Electric Utility Industry for 1977 (Washington, October 1978), 24.

more than tripled since 1972, Table 6-2 shows that the prices of the petroleum-based fuels have increased at a much more rapid rate. The price of natural gas has increased by 312 percent during the last six years for which data are available. Coal is now by far the cheapest of the fossil fuels per Btu consumed, though it is more expensive than nuclear, which in 1976 averaged from 49¢ to 63¢ per million Btu's [12].

The data in Table 6-2 illustrate that the conversion by the electric utility industry to a non-petroleum-based fuel is a process which was undertaken by the industry in response to relative supply and price conditions in the fuel market. This process of change has been furthered by recent energy legislation through the Power Plant and Industrial Fuel Act of 1978, which prohibits the use of oil or natural gas (with certain exceptions, including gas from geopressed reservoirs, to be discussed in Chapter IX) as the primary fuel in newly constructed base-load generation facilities. However, these fuels may be used for new peak-load generation in certain other cases where environmental restrictions or siting problems would prohibit the use of an alternative fuel. Existing facilities are limited to the proportion of natural gas to total fuel used during the 1974-1976 period, and are not allowed to use any natural gas for base-load generation after 1990, again subject to a certain set of exemptions. Given recent assessments of the supply of natural gas, there is some question whether mandatory conversion, particularly of peak-load plants, can be justified on economic grounds [13]. This issue will be discussed more systematically within the section on fuel conversion in the Texas utilities.

B.4. Regulation

The central responsibility for regulation of the electric utilities has historically rested with state and local regulatory bodies, particularly with state public utilities commissions. The scope of federal regulatory activity, however, has increased in recent years. This is due to increased concern with the environmental effects of power plants and electricity generation, the rising importance of nuclear power, the rapidly rising costs of fuel and capital, and increased efforts to prevent blackouts through power-sharing arrangements. Because of these concerns, several federal agencies apart from the Federal Energy Regulatory Commission (FERC) are active in overseeing aspects of the electric utility industry, including the Environmental Protection Agency, the Nuclear Regulatory Commission, and the Securities and Exchange Commission.

TABLE 6-2
COSTS OF FOSSIL FUELS, UNITED STATES, 1972-1977
(Dollars Per Million Btu Consumed)

Year	Composite	(Annual % Change)	Coal	(Annual % Change)	Oil	(Annual % Change)	Gas	(Annual % Change)
1972	41.1		38.4		62.1		31.1	
1973	48.4	(17.8)	41.9	(9.1)	70.3	(26.1)	35.2	(13.2)
1974	89.0	(89.0)	67.8	(61.8)	183.2	(134.0)	50.1	(42.3)
1975	108.3	(21.7)	86.7	(27.4)	202.8	(10.7)	75.0	(49.7)
1976	115.3	(6.5)	88.7	(2.7)	200.7	(-1.0)	102.4	(36.5)
1977	131.8¢	(14.3)	97.5¢	(9.9)	224.3¢	(11.8)	128.3¢	(25.3)
Percent change 1972- 1977		(220.7)		(153.9)		(261.2)		(312.5)

Source: Edison Electrical Institute, Statistical Year Book for the Electric Utility Industry for 1977, 1975 (Washington, October 1978).

The powers of the FERC in utility regulation were expanded in the Public Utility Regulatory Policies Act of 1978, another part of the recent national energy legislation. This act gives FERC authority to order interconnection between electric power facilities and to order an electric utility to provide transmission of electric power between two non-contiguous utilities (wheeling). It also has the power to review automatic cost adjustment clauses, which allow a utility to pass through fuel price increases without a rate hearing. This function had previously been entirely under the jurisdiction of the local or state regulatory agency. The relevance of these powers for utilities not presently engaged in interstate commerce will be examined under the topic of regulation of Texas utilities.

The general increase in regulatory activities at all levels has not been without cost to the utilities. The percentage of administrative and general expenses devoted to dealing with regulatory commissions has risen from 0.6 percent to 2.2 percent of expenses between 1967 and 1976, or an average rate of increase of 15.5 percent per year [14].

B.5. Capital Expenditures

Capital expenditures in the electric utility industry for 1978 were projected to reach a record \$32.8 billion, a gain of about 18 percent over the previous year (see Figure 6-1). This is over four times the amount spent in 1967, representing an annual compounded growth rate of 12.5 percent. Figure 6-1 also points out the increasing percentage of capital expenditures devoted to the generation of power, from 44.1 percent in 1967 to 69.5 percent in 1978.

There are several factors which have led to the increasingly large capital expenditures by the electric utilities. The foremost is the construction of new, more costly generation facilities, and the conversion or replacement of existing facilities with more expensive coal or nuclear plants. When the utility system is loaded at 70 percent capacity, the amortized cost of a coal facility per kilowatt-hour generated is 11.48 mills, and the cost of a nuclear facility is 14.84 mills. This compares with the amortized cost of a gas plant of only 5.12 mills [15].

(MILLIONS OF DOLLARS)

Figure 6-1

CAPITAL EXPENDITURES BY THE ELECTRIC UTILITY INDUSTRY, 1967-1977

When these unit costs are translated to the actual capacity of generating plants, they become astronomical. A 600,000 kilowatt capacity coal plant constructed for Houston Lighting and Power is estimated to cost about \$250 million by completion in 1980. A 1,200,000 kilowatt nuclear plant constructed for the same utility is estimated to cost over \$1 billion by completion in 1985 [16].

However, the differential in costs between plants fueled by different energy sources does not account for all of the precipitous rise in utility capital expenditures. Other major factors in the rising capital expenditures have been the rapid inflation of utility construction costs and the increasing time required for construction of a plant.

Utility construction costs advanced 112 percent between the years 1965 and 1975 compared to 65 percent for the consumer price index [17]. Construction times have also increased dramatically. During the last decade, a utility plant could be constructed in two to four years. It now typically requires eight to ten years to complete a coal plant and ten to twelve years for a nuclear plant [18]. There are a variety of causes for increased construction times, although it is generally recognized that regulatory delay has played a prominent role.

A utility cannot typically include the ongoing costs of construction in its rate base, and thereby earn a return on this invested capital, until completion of the plant. In the highly inflationary business environment which has dominated the late 1960's and 1970's, increasing lead times have meant sharply escalating construction costs. For example, if construction time for a \$200 million generating plant were lengthened from four to eight years, construction costs would rise by \$86.5 million due only to inflation at the rate experienced by the utilities from 1970 to 1978 [19].

The influence of these various factors upon utility construction costs can be evaluated through examination of Figure 6-2. Direct construction costs of the nuclear plants have risen only nominally compared to the rise in total costs. The major element in this rise has been in the time-related escalation of costs during construction, followed closely by interest expense. Indirect construction costs, which include professional services and construction tools, and the added costs of environmental items, have also played a role in rising capital expenditures.

Source: Philip Hill, Power Generation (Cambridge, Mass.: MIT Press, 1977).

Figure 6-2

COMPARISON OF NUCLEAR PLANT COST ESTIMATES FOR 1000 MW UNITS

C. THE ELECTRIC UTILITY INDUSTRY IN TEXAS AND THE TEXAS GULF COAST

C.1. Industry Structure

The electric utility industry in Texas is the largest of any single state, with combined generating capacity of 46,566,000 kilowatts for the overall industry and 38,476,000 kilowatts for the investor-owned segment of the industry [20]. Twenty-nine companies, twelve of which are investor-owned, generate electrical power. In 1976, six of these investor-owned utilities accounted for almost three-fourths of total statewide generating capacity, as is shown in Table 6-3.

Figure 6-3 shows the location of the utility systems which serve the Texas Gulf Coast, and which account for approximately 40 percent of statewide capacity. With a few exceptions Texas utilities have operated entirely within the state and do not interconnect with the utility systems of other states. Interconnections are only maintained with the member systems of the Texas Interconnected System (TIS), whose members include most of the Texas utilities and generate 80 percent of the electricity consumed in Texas [21].

Because TIS does not interconnect and thus is not engaged in interstate commerce, the Federal Power Commission (the forerunner of FERC) has had no jurisdiction over Texas utilities. Texas is unique in this regard, for utilities of all other states

TABLE 6-3
KILOWATT CAPACITY OF MAJOR UTILITIES IN TEXAS, 1976

	<u>Kilowatt Capacity</u>	<u>Percentage Statewide Capacity</u>
Houston Lighting & Power	11,288,190	26.1
Dallas Power & Light [†]	3,819,244	8.8
Texas Electric Service [†] Company	4,443,382	10.3
Texas Power & Light [†]	6,074,354	14.1
Central Power & Light	3,150,000	7.3
Gulf States Utilities Company*	2,959,652	6.9
TOTAL	31,734,822	73.5

Source: Federal Power Commission, Statistics of Privately Owned Utilities in the U.S. for the Year Ended December 31, 1976, April 1978.

[†] These three utilities are owned by Texas Utilities Company.

* Estimate of Texas capacity of Gulf States, which also operates in Louisiana, is based upon 1977 capacity for generating plants for Texas listed in Federal Power Commission, Principal Electric Facilities: South Central Region, 1975.

are members of regional reliability councils which are interconnected across state boundaries. This situation may change, however, under the new Public Utility Regulatory Policies Act, which gives FERC the power to order interconnection.

The first direct challenge to the isolation of the TIS system from the national grid is coming from Central and Southwest Corporation, a holding company including Central Power and Light, the West Texas Utilities Company, and two utilities in contiguous states. In an effort to maintain its status as a holding company, Central and Southwest Corporation interconnected the West Texas Utility Company with its system in Oklahoma. TIS promptly disconnected from West Texas Utilities, and the Public Utility Commission of Texas ruled in 1977 that it was not in the public interest to interconnect members of TIS with the electric utilities of the Southwest Power Pool, the regional reliability council which borders most of Texas. Central and Southwest has now petitioned FERC to invoke its authority under the new legislation to order interconnection between the Texas and Southwest grids [22]. The outcome of this test is uncertain, and will depend upon whether the interconnection is deemed "in the public interest" and would "encourage the overall conservation of energy or reliability." The impact of a ruling for interconnection could be tremendous for Texas utilities, for it might bring their operations under the jurisdiction of FERC.

C.2. Utility Customers and the Structure of Rates

The growth in sales of Texas utilities from 1965 to 1977 has exceeded the national average, due primarily to a strong growth in residential demand resulting from Texas's rapid population growth and the relatively low cost of electricity. Table 6-4 shows total sales of Texas utilities to have grown by 8.5 percent overall and 13.9 percent for the residential sector, compared to 6.1 percent and 7.2 percent nationally for these respective components.

Forecasts for future electricity demand call for a gradually declining growth rate caused by higher electricity prices, conservation efforts, and load management programs. Growth in peak demand is expected to slow to approximately 5.5 percent annually over the next decade [23].

Source: Energy in Texas, Volume 1: Electric Power Generation (Austin: The LBJ School of Public Affairs, University of Texas, 1976).

Figure 6-3

C.3. Fuel Use

The one characteristic of the Texas utilities which has made them as a group extremely vulnerable to the changing environment of the utility industry is their overwhelming dependence upon natural gas as a source of fuel. Excluding the Texas utilities, natural gas is used as the primary fuel source for only 9.2 percent of the nation's electric utilities, while it is the fuel used for 85.7 percent of the electricity generated in Texas [24]. Texas used almost half of all the gas used for electricity generation in the US in 1977, and the electric utility industry accounted for 20 percent of natural gas consumption in Texas [25].

The dependence of Texas electric utilities upon natural gas is related to the historically low price of this resource. In the period following World War II, natural gas was little more than a by-product of oil production, and was often available at prices as low as 3¢ per million Btu's. In addition to determining the fuel mix of the Texas utilities, these low prices stimulated the statewide development and expansion of energy-intensive industry.

High natural gas prices and mandatory conversion legislation are dramatically altering the fuel situation for the Texas electric utilities. Table 6-5 shows that the projected percentage of generating capability of the Texas investor-owned utilities fueled by natural gas will drop from 91.1 percent in 1976 to 56.5 percent by 1985. The Electric Reliability Council of Texas predicts that, by 1985, 40 percent of added generating capability will be coal or lignite and that nuclear power will supply an additional one-quarter [26].

TABLE 6-4
SALES OF ELECTRIC ENERGY IN TEXAS
(Billions of Kilowatt-Hours)

Year	Total	Residential	(% of Total)	Commercial	(% of Total)	Industrial	(% of Total)	Other	(% of Total)
1965	57.2	16.6	(29.0)	14.9	(26.0)	23.4	(40.9)	2.3	(4.0)
1970	95.2	28.9	(30.4)	23.1	(24.3)	40.1	(42.1)	3.1	(3.3)
1973	120.8	37.1	(30.7)	29.7	(24.6)	50.3	(41.6)	3.6	(3.0)
1975	128.4	40.2	(31.3)	32.2	(25.1)	52.2	(40.7)	3.6	(2.5)
1977	152.0	46.8	(30.8)	36.3	(23.9)	64.6	(42.5)	4.3	(2.8)

Source: Edison Electrical Institute, Statistical Yearbook for the Electric Utility Industry for 1977 (Washington, October 1978).

The process of fuel substitution that would naturally result from the economics of relative fuel prices has been accelerated in Texas through a mandatory fuel conversion order issued by the Texas Railroad Commission, the agency with responsibility for intrastate regulation of natural gas. This order, called Docket 600, restricted deliveries of natural gas as a boiler fuel to a declining percentage of 1974-75 consumption and allowed no new contracts for natural gas as a boiler fuel. The Power-plant and Industrial Fuel Use Act of 1978 goes a step further, allowing (with certain exceptions discussed earlier) no natural gas to be used as a boiler fuel after 1990. The preemptive difficulties caused by this act, the difficulties of rapid fuel conversion, and the recent re-evaluation of natural gas supplies have led to the recent rescission of Docket 600.

The process of fuel substitution has been difficult and expensive for the electric utilities. On a nationwide basis reserve margins (the percentage of excess capacity over noncoincident peak demand) have risen from an average of around 20 percent for the 1960's to over 30 percent in the mid-1970's [27], which corresponds closely to the margin for Texas investor-owned utilities shown in Table 6-5. This excess capacity reflects the transformation of gas plants from base-load to peak-load as new alternate-fuel plants are brought on-line and translates to higher capital costs per unit of output. However, the very high reserve margins of this period are a transitory phenomenon, for as existing units are retired on a normal basis, this margin will return to around 20 percent for the Texas utilities by 1985 (see Table 6-5).

It is interesting to note that while the immediate effect of fuel conversion is higher costs of generation reflecting these additional capital expenditures, the real costs of generation will be lower in the long run because of lower fuel costs. It is estimated that by 1990 the costs of generation per kilowatt-hour in Texas will be only 2.1¢ if planned conversion is undertaken, as opposed to 3.5¢ if it is not. This is true despite the fact that the rate base in the latter case would be 63 percent lower [28].

C.4. Regulation

Two components of regulation of Texas electric utilities have already been discussed; federal regulation through several agencies, including the potential for FERC regulation of these utilities for the first time, and state regulation through the Texas Railroad Commission and its fuel conversion order. The only major component of regulation which has not been covered is facility and rate regulation by state and municipal governments.

Until 1975 Texas was one of the few states without a public utility commission. Rate regulation of intrastate utilities was entirely under the jurisdiction of the municipality or utility district in the service area. In 1975 the Texas legislature

TABLE 6-5
GENERATING CAPABILITY AND PEAK DEMAND FOR TEXAS
INVESTOR-OWNED ELECTRIC UTILITY COMPANIES, 1976-1985

Percentage of Generating Capability					A	B	$\frac{A-B}{B} \times 100 =$
Year	Gas and Oil	Coal and Lignite	Nuclear	Hydro-electric	Total Generating Capacity(Mw)	Noncoincident Peak Demand(Mw)	Gross Peak Margin (Percentage)
1976	91.1	8.8	0.0	0.1	40,614	30,797	31.8
1977	89.5	10.4	0.0	0.1	41,333	32,698	26.4
1978	83.1	16.8	0.0	0.1	44,166	34,655	27.4
1979	80.3	19.6	0.0	0.1	45,578	36,775	23.9
1980	77.8	22.1	0.0	0.1	47,601	39,153	21.6
1981	72.0	22.7	5.2	0.1	51,363	41,538	23.7
1982	66.5	25.4	8.0	0.1	54,392	43,903	23.9
1983	63.3	26.8	9.8	0.1	56,898	45,999	23.7
1984	61.2	28.8	9.9	0.1	58,549	48,182	21.5
1985	56.5	32.0	11.4	0.1	61,009	50,661	20.4

Source: Bruce H. Fairchild, "Capital Needs of Investor-Owned Electric Utility Companies in Texas: 1976-1985," Texas Business Review, January-February 1979, 14.

passed the Public Utility Regulatory Act, which shifted the major responsibility for regulation from the local to the state level. Municipalities individually retained the option of assigning regulatory authority to the Public Utility Commission of Texas (PUC) or retaining that authority themselves. In any case, the PUC has appellate jurisdiction over the rate hearings of municipalities.

C.5. Capital Expenditures

The capital expenditures necessary for the Texas electric utilities to accomplish the conversion from natural gas to coal or nuclear and to meet increasing demand are staggering. Texas utilities are planning a \$23 billion construction program which will almost triple their current electric plant investment by 1985 [29].

These statewide figures are even more accentuated in the Gulf Coast region, which serves the rapidly growing areas of Houston, Beaumont-Port Arthur, and Corpus Christi. Table 6-6 shows 1977 capital expenditures by the three large Gulf Coast utilities--Gulf States, Houston Lighting & Power, and Central Power & Light--was \$881 million. Budgeted expenditures were projected to increase total utility plant by 17.7 percent for the next three years, resulting in a 50 percent increase in total utility plant by 1980.

D. THE FINANCIAL POSITION OF THE ELECTRIC UTILITY INDUSTRY

The preceding two sections have examined the major elements of the changing environment facing the electric utility industry. Rapidly increasing fuel costs, construction costs, and construction times have required massive outlays of capital to construct new

TABLE 6-6
UTILITY PLANT AND CAPITAL EXPENDITURES OF TEXAS GULF COAST UTILITIES
(Millions of Dollars)

	<u>Total Plant Less Depreciation, 1977</u>	<u>Additional 1977 Plant Investment</u>	<u>Percentage Total 1977 Plant</u>	<u>Projected Plant Investment</u>	<u>Percentage Total 1977 Plant</u>
Gulf States Utilities	\$1,616	\$225	13.9%	\$750 (1977-1979)	46.4%
Houston Lighting & Power	\$2,543	\$466	18.3%	\$1,540 (1978-1980)	45.4%
Central Power & Light	\$ 833	\$190	22.8%	\$584 (1978-1980)	70.1%
	<u>\$4,992</u>	<u>\$881</u>	<u>17.6%</u>	<u>\$2488</u>	<u>49.8%</u>

Source: 1977 Annual Reports

generating plants which are nuclear-powered or burn coal, and which pose minimum environmental hazards. These problems are compounded for Texas utilities, due both to their heavy dependence upon natural gas and to their faster rate of growth of electricity sales.

Raising the capital for expansion within the current regulatory and business environment has involved a restructuring of past utility financing arrangements, and the last few years have been some of the most difficult the industry has faced. One commentator notes that for the Texas utilities, "the conversion process has evolved not as a technological obstacle but rather as a financing challenge [30]". This section will examine the primary internal and external sources of the funds used to finance the increased construction costs of new generating facilities by the electric utility industry. Figure 6-4 shows the relative importance of these main sources for the years 1965-1976.

D.1. Internal Sources of Funds

The two principal internal sources of funds are net income resulting from operations and tax items which were deducted in arriving at net income, but which were not actually cash expenses during the year. The relative proportions of these internal sources of funds for 1978 are shown in Figure 6-5.

Non-cash charges to income comprised 56.8 percent of funds generated internally by the investor-owned electric utility industry in 1976. Depreciation is by far the most important component of those funds, followed by reserves for deferred taxes and the investment tax credit.

Depreciation for tax purposes is allowed to be taken either on a straight-line basis, for which yearly depreciation charges for a piece of capital equipment are spread equally over the useful life of the asset, or on an accelerated basis, with larger charges for the first years of asset life. Which method is used will depend upon a complex set of tax regulations and the local regulatory body. If an accelerated basis is used, the excess of accelerated depreciation over straight-line is credited to a "deferred tax" account on the corporate books, and in the later years of asset life this account will be charged with the excess of straight-line depreciation over accelerated depreciation. While this procedure is a common reconciliation of corporate and tax accounting, the electric utilities face the additional problem of how to treat these savings on the regulatory books--i.e., whether to subtract them from the rate base or retain them for internal capital funds.

Source: U.S. Department of Energy, Statistics of Privately-Owned Utilities in the United States for 1976, (Washington: Energy Information Administration, April 1978).

Figure 6-4

SOURCES OF FUNDS FOR THE INVESTOR-OWNED ELECTRIC UTILITIES

The method of accounting by which tax savings are used to reduce the rate base and therefore passed on to the customer is called the "flow-through" method. The justification for using this method is that taxes are properly a part of the rate base, so any reduction in taxes should be passed on to the consumer.

The alternative to the flow-through method is the "normalization" method of accounting. Using this method, a company which elects to use accelerated depreciation for tax purposes sets up a reserve account to represent taxes deferred from the present to the future. This reserve account is excluded from the rate base, so the savings are retained in the company rather than being used to reduce rates paid by the customer. This is the method approved by the PUC for the Texas utilities.

Utilities are also allowed a tax credit on a certain percentage of their yearly investment. Again, the question arises of whether to flow these savings through to the utility customers or to normalize them as a source of internal funds.

Advocates of the normalization method claim the investment tax credit is a government subsidy created to stimulate investment, and that to be effective in changing the investment policy of a utility, it must be retained by the company. Detractors of this position point out that a utility must invest in order to meet its normal business obligations. The Internal Revenue Code allows a utility the credit only if it uses a normalized basis of accounting [31].

Given the huge capital expenditures of the electric utilities, the investment tax credit can potentially reduce taxes to zero. Current law allows utilities to use the credit to offset a declining percentage of total taxes, beginning with 100 percent in 1976, and declining 10 percent per year until 1981, when only 50 percent of total tax liability may be offset with the credit.

The Energy Tax Act of 1978 creates an additional 10 percent credit on "alternate energy property," which includes, among other things, boilers which do not burn oil or gas, equipment to produce, distribute or use energy from a geothermal deposit, and pollution control equipment. This credit, however, cannot be taken on property owned by a utility.

The unifying characteristic of these tax provisions is their dependence upon capital formation by the utilities. The extremely rapid growth in capital expenditure has been matched by a corresponding rise in the amount of tax deductions and credits. Consequently, the percentage of operating revenues used to pay income taxes has fallen substantially, from 9.2 percent in 1960 to 1.0 percent in 1976 [32].

Total Internal Funds 1976 = \$12.8 Billion

Source: U.S. Department of Energy, Statistics of Privately-Owned Electric Utilities in the United States for 1976, (Washington: Energy Information Administration, April 1978).

Figure 6-5

SOURCES OF FUNDS FROM INTERNAL OPERATIONS,
U.S. INVESTOR-OWNED ELECTRIC UTILITIES, 1976

The magnitude of these non-cost tax items should not, however, obscure the fact that they are only a portion of revenues, shielded from taxation or returned to the taxpayer in the form of a credit. The total amount of these revenues is regulated by allowing the utility a fair return on invested capital (the rate base), so the determination of what items will be included, at what price, and how quickly becomes critical to utility income.

Within the current environment of high inflation and extended construction times for new plants, the most controversial item for inclusion in the rate base involves the cost of construction work-in-progress (CWIP), or accumulated construction costs before plant completion. In general, public utility regulatory principles allow only items which are "used and useful" to earn a rate of return, so that construction expenditures for a plant cannot be included in the rate base until the plant goes on-line. The FPC endorsed this basic position in Order No. 555, but stated it "would not adhere to an absolute rule that a plant must be 'used and useful,'" and would allow CWIP to be included if the utility could demonstrate severe financial stress [33]. The PUC follows this guideline, allowing CWIP only "where necessary to the financial integrity of the utility [34]".

Regulation does recognize that the expense of financing ongoing construction is a legitimate business expense which should be borne by the ratepayers. Therefore, an allowance for funds used during construction (AFUDC) is taken as a percentage of construction work-in-progress and added to the rate base. Because it is then shown as an addition to assets, AFUDC must be shown on the books as income, although no cash is received. It is income which cannot be used to meet expenses, pay dividends, or to reinvest in the business. Moreover, with the large capital outlays of recent years, AFUDC now contributes a very substantial portion of income, having risen from 4.8 percent to 28.5 percent of net income for investor-owned utilities from 1966 to 1975 [35]. Recent estimates put AFUDC at 40 percent of earnings of the average utility [36]. Research has shown that investors recognize the poor quality of this portion of utility income, and discount it accordingly [37].

Total External Funds, 1976 = \$13.9 billion

Source: Federal Energy Regulatory Agency. Statistics of Privately-Owned Electric Utilities in the United States for the Year Ended December 31, 1976, April 1, 1978.

Figure 6-6

EXTERNAL SOURCES OF FUNDS, U.S. INVESTOR-
OWNED ELECTRIC UTILITIES, 1976

Time delays in the recognition of legitimate expenditures as part of the rate base is often cited as one of the major causes of the utilities' internal financial difficulties. These "regulatory" lags have risen to an average of 10.8 months from the time the rate increase is requested until it is granted [38].

D.2. External Sources of Funds

Figure 6-6 shows about half of the funds from external sources for the electric utility industry in 1976 came from the issuance of long-term bonds; common stock provided another quarter of these funds. Preferred stock also plays an important role, with the electric utilities issuing more preferred stock than does any other industry. These sources of incremental funds correspond closely to the overall amounts of debt and equity on the utility books.

During the late 1960's and early 1970's, it appeared that the utilities were rapidly becoming overburdened with debt. The proportion of outside financing increased from 44 percent of all sources to 70.5 percent from 1965 to 1970, and debt ratios rose from 51.5 percent to 54.8 percent over the same period [39]. However, as Figure 6-4 demonstrates, the percentage of external financing fell again in the 1970-1976 period to its previously low level. In a similar manner, debt ratios have fallen over this latter period, as shown in Figure 6-7.

While fears of an increasing inability on the part of the industry to generate funds internally, forcing a greater reliance on debt, have not materialized, the cost of debt has placed a heavy burden on the utilities. Average yields on newly issued bonds rose precipitously during the late 1960's and early 1970's from 4.6 percent in 1965 to a height of almost 10 percent in 1975, and have since declined only slightly [40]. Interest payments have taken an increasing proportion of revenues, so that the important interest coverage ratio, measuring the number of times fixed interest charges are covered by net income has declined by 35 percent over the period (see Figure 6-7). As a consequence of this decline, the credit ratings of 43 securities of major investor-owned electric utilities were reduced in 1974 alone, resulting in even higher interest costs for future security issues by these companies [41].

Source: Federal Energy Regulatory Agency. Statistics of Privately-Owned Electric Utilities in the United States for the Year Ended December 31, 1976, April, 1978.

† The ratio of long-term debt to total capitalization.

* The ratio of net income after taxes to interest payments on long-term debt.

Figure 6-7

DEBT AND TIMES-INTEREST-EARNED RATIO FOR THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY, 1965-1976

A major consequence of this period of low interest-coverage ratios has been felt in the market for utility equities. Prevented from financing their plant expansion with debt by their declining interest-coverage ratios, the utilities were forced to issue common stock at prices that were often below the book value of their existing shares of common stock. The 1974 market price of common stock of utilities included in the Moody's Utility Index averaged only 65 percent of book value [42]. As the price of new issues must closely approximate that of existing shares, every new share issued reduces the value of assets corresponding to the old shares. Eighty percent of the companies in a sample of those issuing new common stock from 1972 to 1977 suffered dilution in the value of their existing equity [43].

This decline in utility common-stock prices was a reflection of changing investor perception of the risk/rate-of-return profile of the electric utilities when compared with that of other industries. Utility securities had been historically considered defensive, with their prices varying less than the overall market average. This was a reflection of the steady demand and predictable costs which the utilities had enjoyed. Because of the changed environment of the late 1960's and early 1970's, earnings lost a great deal of their stability, increasing the market risk factor to almost that of a portfolio of industrial securities.

One commentator notes:

"Electric utilities have, until recently, constituted a low-risk industry; the persistence of the psychology of growth, rising future electric demand, fuel prices, and plant construction costs were highly predictable. Not only have all of these factors today become highly unstable, but the increased potential for financially damaging federal and state regulatory actions adds still further uncertainty" [44].

Consequently, during the period 1965 to 1976, electric utility equities yielded an average return of only 3.1 percent, as compared to 11.3 percent for the industrial average [45].

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry for 1977, Washington October 1978, 66.

Figure 6-8

MOODY'S YEARLY STOCK-PRICE AVERAGE FOR 24 UTILITIES

However, if current short-term trends hold, it is possible that this period of extreme difficulty for the electric utilities may be coming to an end. Revenues now appear adequate to insure debt coverage at acceptable ratios, and utility equity prices have rebounded somewhat, as is shown in Figure 6-8.

E. THE FUTURE OF THE ELECTRIC UTILITY INDUSTRY

Speculation about the future while the current environment is still in such a state of change is risky, but several trends seem to be emerging. Perhaps the most notable has been an accentuation of the decline in the growth rate of electricity demand. As noted previously, before the Arab oil embargo electricity demand was growing at an annual rate of about 7 percent, and dropped to 3.5 percent in subsequent years. During 1978, the growth rate fell to 2.7 percent [46]. Generating capacity, however, has kept growing based upon past demand projections. As a result utilities now have excess capacity, with reserve margins reaching a record of 33.2 percent in the summer of 1978, according to the Edison Electrical Institute [47].

An ironic consequence of this excess capacity, linked with high capital costs, regulatory delays, and political problems encountered in the construction of nuclear plants, is that future capacity may be insufficient to meet demand. Utilities across the nation are postponing orders for new plants, especially nuclear plants. In contrast to the 1000 nuclear plants which were once predicted to be in service by the turn of the century, only 230 new plants will be added to the 72 now in operation by that time [48]. Even Gulf States Utilities has cancelled two million-kilowatt nuclear plants, although its growth in electricity sales substantially exceeds the national average. Likewise, San Diego Gas and Electric, experiencing a five percent yearly growth in electricity demand, has scrapped plans to increase capacity of a fossil-fuel unit and construct a 45 Mw geothermal plant due to a shortage of capital. Indeed, almost half of the capacity that utilities had planned to add by 1987 has yet to be started [49].

These signs are at odds with predictions of electricity demand and corresponding capital requirements based upon past trends. One study predicts the existence of a severe financial shortage after 1985, and the continued necessity of financing expansion through the issuance of equity at prices below book value, if changes in regulatory procedures are not allowed [50].

What is clear is that while the utilities have emerged not altogether unscathed from the changed environment of the years immediately following the Arab oil embargo, no short-term resolution of their problems or return to a stable demand-cost environment can be expected. Nuclear power's medium and long-term role in providing a major portion of electricity generation is increasingly in doubt, and environmental and transportation problems associated with coal limit the attractiveness of this resource. The repeal of Docket 600 and the exemptions to the phase-out of gas mandated by the Powerplant and Industrial Fuel Use Act indicate there is a growing awareness that natural gas may continue to play an important role in the fuel mix of the electric utilities. Moreover, the response of electricity demand to changing relative energy prices is uncertain, casting even more doubt upon the necessity for costly capital expansion. In short, the electric utilities face tremendous uncertainties during the remainder of this century and must seek regulatory alternatives to ensure flexibility in response to these changes.

The first of these is the fact that the system is not a simple one. It is a complex system, and the behavior of the system is not predictable. The second is that the system is not a simple one. It is a complex system, and the behavior of the system is not predictable. The third is that the system is not a simple one. It is a complex system, and the behavior of the system is not predictable.

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CHAPTER VII

POTENTIAL GOVERNMENTAL PARTICIPANTS IN RESOURCE DEVELOPMENT

A. CHAPTER PURPOSE AND SCOPE

This chapter presents descriptions of the governmental units which are most likely to play significant (mostly, regulatory) roles in the development of the geopressured-geothermal resource. These descriptions by no means cover all units which could exert influences on resource development but, rather, are intended to quickly familiarize the layman with the germane characteristics of the most obviously "important" units. Federal governmental units are covered first, followed by state and local units. Federal and state congressional bodies, such as house and senate committees, which may be expected to play important roles in shaping resource development, are not covered here.

B. FEDERAL GOVERNMENTAL PARTICIPANTS

Federal regulation of natural resource development of any kind has become an increasingly important determinant of that development over the past ten years. Multifarious federal agencies regulate virtually every aspect of any energy development project. For example, labor relations now involve fair employment and affirmative action programs, and embrace establishment and enforcement of detailed health and safety standards. Many other special fields are similarly affected by widening federal regulation. However, for geopressured-geothermal development along the Gulf Coast of Texas, six federal agencies can be identified as the major probable participants in that development's regulation. These are: The Department of Energy, The Environmental Protection Agency, The Department of Interior, The National Oceanic and Atmospheric Administration, The Department of Justice, and The Internal Revenue Service.

B.1. Department of Energy (DOE)

Two elements within DOE are charged with important regulatory tasks bearing on geopressured-geothermal development: The Federal Energy Regulatory Administration [1] and The Economic Regulatory Administration [2]. (DOE and its predecessors have also played large roles in the funding of geopressured-geothermal research; see Chapter III for a chronology of this support.)

B.1(a) Federal Energy Regulatory Administration (FERC). The FERC is an independent five-member commission, nominally within the Department of Energy, which succeeded in 1977 to most of the functions of the former Federal Power Commission [3]. It regulates interstate natural gas and electricity sales and transportation. Its activities in the natural gas industry are detailed at length in Chapter V, Section E, and its activities in the electric power industry are discussed in Chapter VI, Subsection B.4.

B.1(b) Economic Regulatory Administration (ERA). The ERA is a principal element of the DOE and is under the direction of the Secretary (in contrast to the independent status of the FERC). The ERA is charged with responsibility for economic and regulatory programs which are not the responsibility of the FERC. It promulgates certain gas pricing and allocation regulations and fuel conversion programs for utilities and industry; it surveys market conditions and monitors supply and price trends. It has subordinate offices of enforcement, fuels regulation, regulations and emergency planning, and utility systems.

B.2. Environmental Protection Agency (EPA)

Federal participation in programs which may have a significant effect on the environment triggers action by any federal agency under the National Environmental Policy Act (NEPA) [4], with its requirements for environmental impact assessment. Beyond this environmental protection rule applicable to all federal agencies, the EPA [5] has major environmental regulatory responsibilities which will affect geopressured development directly.

The Clean Air Act [6] is implemented by EPA regulations which impose restraints on the siting of new industrial facilities in air quality control regions which are nonattainment areas for the achievement of prescribed ambient air standards. Siting permits may be issued currently under an emission-offset policy which requires the reduction in pollutant emissions from other sources to an extent which will more than compensate for new emissions [7]. Construction or modification of major pollution generating facilities in these areas is in theory prohibited and in practice inhibited until the state has an implementation plan which meets the federal statutory schedules for attainment of prescribed air quality. (See the discussion at VII, C.5., for more information on Texas' state implementation plan). Should facility siting be planned in an area which has attained the national ambient air standards, the EPA's rules for prevention of significant deterioration apply [8].

Under the Federal Water Pollution Control Act Amendments of 1972 [9], the EPA controls pollutant discharge which affects navigable waters. This control is exercised through the granting of National Pollutant Discharge Elimination System (NPDES) permits. Currently, it seems unlikely that disposal of geothermal effluents into surface waters would be permitted unless extensive cooling of the fluid wastes were undertaken in order to avoid thermal pollution. Additionally, the presence in geothermal wastes of certain substances harmful to marine or plant life would likely cause denial of a surface disposal permit unless the harmful substances were removed before disposal.

EPA regulatory implementation of the Safe Drinking Water Act of 1974 (SDWA) [10] is not yet complete. These regulations, when effective, can be expected to cause major substantive and procedural changes in existing Texas underground disposal well permitting. Proposed regulations under the SDWA are now being coordinated with a major new regulatory system, also under the EPA's jurisdiction, to implement the Resource Conservation and Recovery Act of 1976 (RCRA) [11]. The RCRA completely replaces the old Solid Waste Disposal Act. The RCRA prescribes a comprehensive hazardous-waste management system. In its draft regulations, the EPA says it is establishing a "cradle-to-grave" management control system for hazardous wastes. "Solid waste" is defined broadly to include virtually any type of waste material, such as drilling mud.

The EPA's long-range goal is to incorporate SDWA and RCRA regulations in comprehensive NPDES regulations, the daily management of which would be delegated to the states. When this merging of regulations is complete, probably, a very long time in the future, all important pollution permitting, except air pollution permitting, would be handled under one system.

B.3. Department of Interior

This department has several agencies which are involved in mineral development, land and water resource planning, and protection of fish and wildlife. Their programs and rules can significantly impact Gulf Coast geothermal development. The Bureau of Land Management and the Geological Survey regulate and permit development affecting, respectively, federal surface resources and federal mineral resources [12]. Fish and Wildlife Service programs for the safety of marine and other wildlife, and in particular, the determination of endangered species, can seriously affect resource development plans [13]. Specifically, effluent disposal, a major problem for geothermal development, must consider protection of marine life.

B.4. National Oceanic and Atmospheric Administration (NOAA)

This agency has been charged with regulation of state coastal management programs developed under the Coastal Zone Management Act of 1972 [14]. The act was intended to improve state and local land and water use planning and regulation. Major amendments to the act in 1976 established the Coastal Energy Impact Program [15]. This was apparently intended to require special consideration and planning regarding location of energy facilities in the coastal areas. Provision was made to compensate coastal states for off-shore energy development, and consequent on-shore facilities and environmental problems. The NOAA will delegate its coastal zone management responsibilities to states which develop their own plans, if those plans are approved by the Secretary of Commerce. Texas spent about three years developing a proposed coastal zone management program under direction of the General Land Office [16]. However, at present, the state does not have a program which is ready for formal submission to the Secretary of Commerce.

B.5. Justice Department

The U.S. Justice Department [17] is the federal agency most directly concerned with prevention of monopolistic practices by domestic American business. One of Justice's principal concerns is that all aspects of energy production not become dominated by a small group of firms. Evidence of this concern is found, for example, in Justice's monitoring of oil and gas producer penetration of the coal industry [18] and its public speculation on divestiture by oil producers of their pipeline subsidiaries [19]. Were Justice not to consider geopressured-geothermal development as, essentially, oil and gas development, it might attempt to encourage development of the resource by firms other than large oil and gas producers.

B.6. Internal Revenue Service

The Internal Revenue Service (IRS) [20] is an agency within the US Treasury Department and is responsible for the collection of taxes which support the federal government. Since 1862, it has collected taxes on income earned by individuals and corporations [21]. Of immediate significance for geopressured-geothermal development, the IRS determines permissible allocations of tax deductions among participants in natural gas development projects (see Chapter V, Section E.3.) and administers tax incentives to development of unconventional energy resources (see Chapter IX).

C. STATE GOVERNMENTAL PARTICIPANTS

State regulation of resource development will initially fall most directly in the Texas Railroad Commission, which has historically regulated the resources most parallel to the geopressured resource, oil and gas resources. The Department of Water Resources, Public Utility Commission, General Land Office, and Texas Air Control Board may also be expected to play regulatory roles.

C.1. Texas Railroad Commission (TRC)

The TRC is a three-member elected commission. It was the first Texas state agency to be created (1890) and initially regulated only railroads [22]. In the early 1900's it took on regulation of oil and gas development. It now regulates all common carriers and nearly all mineral extraction and related waste disposal. The TRC has initial responsibility for classification of wells as geopressured or otherwise; this is of considerable consequence to producers of natural gas from geopressured reservoirs who would charge unregulated gas prices or claim tax benefits related to geopressured natural gas production (see Chapter IX). Under Texas's Geothermal Resources Act [23], the TRC has the dominant responsibility for regulation of exploration, development, and production of geothermal energy in the state; a 1979 amendment to that act makes it clear that the TRC also has jurisdiction over disposal of wastes from geothermal development.

In addition to responsibility for energy production, the TRC also has responsibility for gas distribution in unincorporated areas, appeals from gas distribution decisions in incorporated areas, and all intrastate gas transmission activities.

C.2. Department of Water Resources (DWR)

The DWR was created in 1977 by merger of three agencies which dealt with water resources: The Water Development Board, Water Quality Board, and Water Rights Commission [24]. In general, the duties of the DWR fall into two categories: (1) the allocation of, and rate setting for, use of the state's water resources and (2) the monitoring and protection of the quality of the state's water resources.

If the EPA eventually delegates to the state responsibility for the Texas portion of the National Pollutant Discharge Elimination System, it will do so in toto. The DWR is the natural agency to receive most of the delegation. However, delegation of responsibility for disposal of wastes from geothermal operations should be delegated to the TRC because it has that responsibility under the Geothermal Resources Act. At this writing (Summer, 1979), the TRC and EPA have not reached agreement on the regulations by which the TRC would administer discharge permits, were the EPA to delegate to the TRC some NPDES responsibility.

Problems could exist, then, both in securing delegation of NPDES responsibility to the state and in coordinating permitting responsibilities between the TRC and DWR, should that delegation occur.

C.3. The Public Utility Commission of Texas (PUC)

The Public Utility Commission was created in 1975 by the passage of the Public Utility Regulatory Act [25]. This Act charges the commission with representing and protecting the public interest while maintaining the financial integrity of the utilities. Texas was the last state to pass such a law.

The commission has exclusive original jurisdiction over electric, water, and sewer utility rates in unincorporated areas of Texas. Cities were given the option to retain their jurisdiction or turn it over to the commission. With few exceptions, incorporated areas of Texas have retained their original jurisdiction, but the commission has jurisdiction over their decisions in the event of an appeal.

The commission consists of three members appointed by the Governor for staggered six-year terms. Its staff is divided into 5 divisions operating in two major areas, rate evaluation and rate regulation. Rate evaluation is concerned with determination of the fairness of utility rates with regard to the cost of service and with monitoring utility compliance with the Commission's accounting and ratemaking rules. Rate regulation operates through public hearings, during which evidence regarding utility rates, operations, and service is presented.

There is no legislation directing the Public Utility Commission to develop policies to encourage utility use of alternative energy sources. However, such legislation has been introduced, and propositions are being considered to include a direct pass-through of R & D expenses in fuel adjustment clauses.

C.4. General Land Office (GLO)

The Commissioner of the GLO is elected to four-year terms. The position of Commissioner and, hence, the GLO date from 1836 and are constitutionally created [26].

The GLO has general responsibility for management of state-owned lands. It therefore leases some 900,000 acres of upland public free school lands and some 4,000,000 acres of submerged public free school lands. It leases the state's mineral interests in some 16,800,000 acres, mostly off shore [27].

The Geothermal Resources Act directs the Commissioner of the GLO to lease lands under his control in such a way as to encourage rapid and orderly development of such geothermal resources as may lie beneath them. To facilitate decisions to that end, the GLO has already conducted rather thorough analyses of the economic, environmental, and regulatory impacts of geopressured-geothermal development [28].

C.5. Texas Air Control Board (TACB)

The TACB is a relatively new agency (1965) headed by nine members, each appointed for a six-year term [29]. It administers the Texas Clean Air Act and delegated portions of the Federal Clean Air Act. Its monitoring of and permitting for air pollution could affect development of geopressured-geothermal resources.

Under the Federal Clean Air Act, the EPA has regulatory authority over air pollution permitting in areas which are not now in compliance with ambient air quality standards for various pollutants ("non-attainment areas") and for areas which are. In the former areas, "offset" rules apply under which the would-be polluter must clean up more pollution than he causes. In the latter areas, rules for prevention of significant deterioration of ambient air quality apply. In general, coastal areas near petrochemical complexes and urban areas are now non-attainment areas. Texas has a State Implementation Plan under which EPA regulatory authority has largely been delegated to the TACB; more of this authority will presumably be delegated shortly, when portions of the State Implementation Plan are amended to EPA's satisfaction.

D. POSSIBLE LOCAL GOVERNMENTAL PARTICIPANTS

In the event of widescale commercial development of geopressured geothermal resources in Texas, local governments might participate actively in at least three ways. First, local government units such as counties, municipalities, and special districts could be involved in the resource development planning process. Their active involvement in planning decisions would be anticipated because it is the responsibility of these units of government to regulate land use activities through taxation, zoning, and nuisance control measures. Additionally, local governments in affected areas would be expected to plan for, and attempt to influence, geothermal development impacts. These impacts might include environmental effects such as pollution of underground water reservoirs, or they might relate to increased demand for social services resulting from growth in population and from growth in economic activities.

Second, local governments are potential market partners to geothermal developers in the private sector. Preliminary contacts with local government representatives indicate that units of local governments, such as municipalities and water districts, might use or distribute geopressured-geothermal products. For example, municipal utility districts could use natural gas to burn municipal waste, or they could contract with geothermal resource developers to buy and distribute geothermal water to residential and commercial-industrial customers for home heating and for process heat applications.

An example analogous to municipal distribution of geothermal water for industrial process heat now exists in San Antonio, Texas, where the city-owned utility boils water which it sells to commercial-industrial users.

Third, uncertainties regarding geothermal development will presumably decrease in the future and, with this decrease, local governments might elect to commit taxpayer funds to government development of the resource. Currently, Texas water districts, including municipal utility districts, water improvement districts, water control and improvement districts, and underground water conservation districts, have legal authority as expressed in the Texas Water Code [30] to engage in the development of the state's geothermal resources for residential, commercial, and industrial uses.

One possible arrangement for this type of role is the formation of a consortium of local governmental units within one, two, or more counties. This is not a new institutional arrangement for energy resources development in the state. Already in existence is the Texas Municipal Power Agency (TMPA), a public corporation formed by the cities of Garland, Bryan, Denton, and Greenville to generate power for the four cities. Presently, TMPA is involved in plans to mine lignite and construct a lignite-powered plant in Grimes County, Texas. The TMPA arrangement indicates that municipal utility districts in the gulf coast counties might one day form public organizations to participate with industry to exploit the geopressured geothermal resources of the region.

CHAPTER VIII
INDUSTRIAL USERS OF THERMAL ENERGY

A. OVERVIEW OF ENERGY CONSUMPTION

The industrial sector of the United States economy is the largest user of energy of any sector. In 1975 it accounted for about 40 percent of total United States energy usage. This compares with about 20 percent for the residential sector, 15 percent for the commercial sector, and 25 percent for the transportation sector [1]. The approximate gross energy consumed by the industrial sector in 1975 was 24,167 trillion Btu's. This figure includes all purchased energy, plus that produced and consumed "in house" by certain manufacturers. Table 8-1 gives a breakdown of energy usage by the major industrial groups.

TABLE 8-1
ESTIMATED GROSS ENERGY CONSUMED IN THE UNITED STATES
BY INDUSTRIAL USERS, 1975
(Trillions Btu's)

		<u>Percent of Total</u>
Energy produced and consumed "in house," all industries	3,248	13.4
Purchased by Major Industrial Users:		
Food & Kindred Products	1,284	
Paper & Allied Products	1,725	
Chemicals & Allied Products	4,997	
Petroleum & Coal Products	2,083	
Stone, Clay & Glass Products	1,617	
Primary Metals Industries	<u>4,031</u>	
Total	15,737	65.2
Purchased by all other Manufacturing	<u>5,182</u>	<u>21.4</u>
Total Purchased and Produced	24,167	100.0

Source: The Conference Board, Energy Consumption in Manufacturing, a report to the Energy Policy Project of the Ford Foundation, New York, 1974.

A.1. Energy Requirements

Natural gas is consumed as an industrial fuel more than any other resource, followed closely by petroleum and electricity. Of lesser importance as fuels are coal, coke and hydro-electric resources. By 1978 the industrial sector increased consumption to 28,129 trillion Btu of energy from all fuel sources. Table 8-2 categorizes total consumption by fuel type and an approximate cost for each fuel:

TABLE 8-2
INDUSTRIAL CONSUMPTION BY FUEL TYPE, 1978

<u>Energy Source</u>	<u>Trillion Btu</u>	<u>Percent of Total*</u>	<u>Cost (Millions \$)</u>
Natural Gas	8,274	29.4	\$ 7,860
Petroleum	6,737	24.0	6,400
Electricity Distributed	2,729	9.7	2,593
Electrical Energy Loss Distributed	6,782	24.1	6,443
Coal	3,441	12.3	3,269
Hydroelectric	35	.1	33
Net Coke Imports	131	.5	124
Total	28,129	100%	\$26,722

*Total reflects rounded figures

Source: United States Department of Energy, Monthly Energy Review, Washington, March 1979, 22.

A.2. Geothermal as a Source of Energy

To this date, the most widespread interest and application of geothermal energy has been for either electric generation, as exemplified by the Geysers area in California, or as a supply of thermal energy for space heating, agricultural production, and industrial process applications. These thermal energy uses have been at temperatures below 350°F (177°C), which is thought to be the minimum practical temperature for electricity generation. Geothermal application in the areas of space heating and agricultural production have reached significant proportions, while industrial process use is still very limited.

There are two classifications for space heating systems, district and individual. The most significant uses are in the district heating category, as exemplified by the heating system of Reykjavik, Iceland. There are two notable examples of individual space heating systems, one in Rotorua, New Zealand and the other in Klamath Falls, Oregon. Both systems have proved to be economical.

The application of geothermal energy to agricultural production falls into three basic categories. By far the most extensive use is in greenhouses, followed by much more restricted applications in animal husbandry and aquaculture. Within the past several years numerous greenhouse and aquaculture projects have been developed in the western United States. Klamath Falls and Lakeview, Oregon, both contain greenhouse and aquaculture projects. There are numerous locations in Idaho utilizing geothermal heat for aquaculture projects, and some in California supporting greenhouse projects.

Moreover, there are also two instances in this area where geothermal energy is applied to industrial processes, with a third project in the development stage. The Medo-Bel Creamery in Klamath Falls, Oregon, utilizes low temperature fluid to pasteurize milk; Geothermal Food Processors at Brady Hot Springs, Nevada, utilizes high temperature fluid for dehydration of onions and other vegetables; and the Ore-Ida Foods, Inc. plant located in Ontario, Oregon, is currently converting to geothermal energy for potato processing [2].

Because of the escalating costs of using fossil fuels, it is expected that non-petroleum fuel shares of the future industrial energy market will increase significantly. Therefore, the possibility of employing geothermal energy for industrial processing may ultimately prove to be an important use of the resource. The remainder of this section addresses that possibility.

B. POTENTIAL GEOTHERMAL APPLICATIONS IN INDUSTRY

A significant aspect in industrial processing requirements is that the greater portion of energy used is in the form of thermal rather than kinetic energy. Table 8-3 describes a utilization breakdown of energy for the industrial sector.

TABLE 8-3
PERCENTAGE UTILIZATION OF ENERGY BY ALL INDUSTRIES

<u>Category</u>	<u>Usage %</u>	<u>Trillions Btu</u>
Process Steam	40.6	11,420.4
Direct Process Heat	27.8	7,819.9
Electric Drive	19.2	5,400.8
Feedstock for Chemicals	8.8	2,475.4
Electrolytic Processes	2.8	787.5
Other	<u>0.8</u>	<u>225.0</u>
	100%	28,129.0

Source: Stanford Research Institute, "Patterns of Energy Consumption in the United States," Office of Science and Technology, Executive Office of the President, Washington, January, 1972, and Monthly Energy Review, March 1979, op. cit.

Energy use for process steam and direct process heat application has been the subject of several recent studies [1, 3, 4, 5]. Each provided information on both heat usage amounts required for certain processes in order to obtain a finished product, and the temperature range requirements for each product category. Fraser [1] examined the possibility of solar application to industrial processes, while the others specifically studied the possibility of a geothermal resource application for industrial processes. All of the studies focus on the six most energy-intensive industrial groups. These groups, presented in descending order of energy intensity, are: (1) primary metal industries; (2) chemical industries; (3) petroleum and coal products industries; (4) stone, clay and glass industries; (5) paper and allied products industries; and (6) food and kindred products industries.

However, ranked in terms of direct thermal usage, the order becomes: (1) food and kindred products; (2) paper and allied products; (3) chemicals and allied products; (4) petroleum products; (5) stone, clay and glass products; and (6) primary metal industries [4]. Table 8-4 summarizes direct thermal application data by temperature range and projected 1985 Btu use for the United States industrial sector.

In the state of Texas, industrial application accounts for 43.5 percent of the state's total energy consumption [6]. Table 8-5 shows the total amount of fuel consumed in Texas by all major Standard Industrial Classifications (SIC), including the six intensive users of energy already mentioned.

As in other states, Texas manufacturers predominately use their energy for producing steam for processing or for direct thermal application during production. Some of the temperature ranges are comparable to those available from the geothermal resource. Appendix C of this report provides more detailed information on specific industrial processes and their energy requirements within the temperature bounds of geothermal.

The application of geothermal energy to industrial processing has, as mentioned, been the subject of several previous studies [2, 3, 4, 5, 7]. Only two, [5, 7] deal extensively with the subject of geopressured-geothermal resources. One study is generally limited to the geographical locale of the State of Louisiana, and the other study, although dealing with the state of Texas, looks at only one potential user of the resource, the Frash sulfur mining industry. Therefore, to date very little work has been done to analyze the potential geopressured-geothermal process heat market in Texas.

TABLE 8-4
ESTIMATED USE OF INDUSTRIAL STEAM
BY TEMPERATURE GROUPS TO 200°C

Industry	Temperature Range (°C)	Est. 1985 Energy Use (10 ¹² Btu)	Percent of total Industrial Energy
Food & Kindred Products	150-174	174	.4
	125-149	781	1.8
	100-124	781	1.8
		<u>1,736</u>	<u>4.0</u>
Paper & Allied Products	175-199	1,345	3.1
	150-174	564	1.3
		<u>1,909</u>	<u>4.4</u>
Chemicals & Allied Products	175-199	521	1.2
	150-174	521	1.2
	125-149	608	1.4
		<u>1,650</u>	<u>3.8</u>
Petroleum	175-199	87	.2
	150-174	738	1.7
	125-149	738	1.7
		<u>1,563</u>	<u>3.6</u>
Other Industries	175-199	2,127	4.9
	150-174	2,127	4.9
	125-149	2,343	5.4
	100-124	738	1.7
	75-99	217	.5
		<u>7,552</u>	<u>17.4</u>
Industrial Space Heating	50-74	2,343	5.4
		Total	38.6

Source: C. D. Hornberg and B. Lindal, [3], 21.

TABLE 8-5
ENERGY CONSUMPTION BY TEXAS INDUSTRY

<u>SIC Code & Name</u>	<u>Total Fuel 10¹² Btu</u>	<u>Percent of Total</u>
20-Food & Kindred Products	52.14	2.3
22-Textile Mill Products	3.75	.2
23-Apparel, Other Textile Products	5.77	.3
24-Lumber & Wood Products	10.92	.5
25-Furniture & Fixtures	2.46	.1
26-Paper & Allied Products	49.30	2.2
27-Printing & Publishing	7.57	.3
28-Chemicals, Allied Products	911.80	40.4
29-Petroleum & Coal Products	757.30	33.5
30-Rubber, Misc. Plastic Products	11.57	.5
32-Stone, Clay, Glass Products	108.50	4.8
33-Primary Metal Industry	249.20	11.0
34-Fabricated Metal Products	30.13	1.3
35-Machinery, Except Electric	28.42	1.3
36-Electric, Electronic Equipment	10.07	.5
37-Transportation Equipment	17.88	.8
38-Instruments, Related Products	1.23	.1
39-Misc. Manufacturing Industry	1.02	.1
Total	2,259.03	100.2*

*Total reflects rounded figures

Source: Governor's Office of Energy Resources: State of Texas Energy Conservation Plan, Vol. III - Energy Savings Calculations (June 1977) p. 30.

C. MARKET STUDY

C.1. Introduction

The geopressed-geothermal resource which underlies the Texas and Louisiana Gulf Coast is co-located with a broadly diversified industrial region. The market survey was conducted of manufacturers in the thirty-county region along the Texas Gulf Coast (See Figure 8-1.) In 1977 manufacturers in this area shipped products valued at \$38,987.8 million, representing 52.9 percent of the total value of Texas shipments [8]. Were this region ranked separate and with other states according to its value, it would rank tenth, underlining its industrial importance.

Source of Map: Bebout, 1977.

Figure 8-1: COUNTIES OF MARKET SURVEY

To date, most interest in the geopressured-geothermal resource has centered upon the methane component. However, the situation of a vigorous industrial sector co-located with a potential thermal resource provides a unique utilization opportunity for the geothermal resource. The thermal component of the resource consists of demethanized geothermal brine, which could be used alone for low-temperature (350°F) process heating and chilling, or in conjunction with the methane component to obtain higher temperatures for other processing requirements.

A total of 591 industrial firms were identified and surveyed. All of these firms have some process heat and/or chill needs at or below the probable temperature range of the geopressured-geothermal brine.

C.1(a) Objectives. The objectives of the market survey were: (1) to identify the potential market for the thermal or the combined thermal and gas component along the Texas Coast; and (2) to determine the factors which are important to members of this potential market in their choice of equipment in general and of the geopressured-geothermal equipment in particular.

C.1(b) Description of Survey Area. The Gulf Coast Region of Texas is an area of great diversity in manufacturing and production. The leading forces in Texas manufacturing are the chemical and petroleum complexes located around Houston and along the Gulf Coast. These complexes have added around \$6.2 billion to the Texas economy. Next in terms of dollars added to the economy is the petroleum refining sector which has generated another \$3.8 billion. Texas still maintains 25% of the nation's crude refining capacity, largely located in the Gulf Coast area [9].

On the side of production, Texas is one of the major contributors to the United States' overwhelming lead in world food production. There are 158 food product plants located along the Gulf Coast, processing a range of goods including meat, poultry, dairy products, grains and cereals, vegetables and citrus fruits, and of course, seafood. The food and kindred products industry ranks fourth in value added to new materials by manufacturing with a total of \$2.7 billion in 1976 [10]. Machinery manufacturing is the third ranking industrial concern with \$3.2 billion in the value added category [11]. A recent *Fortune* magazine survey shows Texas ranking number one in terms of site locations for companies planning to construct new plants in the next five years [12].

The thirty-county area of the market survey contained six major Standard Metropolitan Statistical Areas (SMSA) and an approximate population of 4,057,400 [13]. Figure 8-1 shows the six SMSA locations along the geopressured zones and lists the counties included in the survey area.

C.2. Methodology

C.2(a) Survey Sample. A total of 591 industrial firms in fourteen two-digit SIC's were identified from existing data on Texas manufacturers [14]. The criteria for selecting this group of potential respondents included employment figures (a minimum of 8 employees) and process heat or chill requirements in plant at or below 325 - 350°F, the probable temperature range of the geopressured-geothermal brine. Information on temperature ranges for process heating and chilling were taken from works by Fraser [1] and Hornburg and Lindal [3]. This was combined with descriptions of actual processing steps to determine which SIC groups were to be targeted for the survey (a discussion of processes and temperature requirements may be found in Appendix C of this report.) A summary of the SIC groups chosen and subsequently surveyed is given in Table 8-6.

C.2(b) Survey Instruments and Administration. The concepts for this study were formulated over a six-month period within which two smaller, yet less concentrated, surveys were conducted in the two counties of Galveston and Brazoria. Information was obtained from a Dunn and Bradstreet listing [15] for mailout purposes. These surveys included requests for information on industrial process heat/chill requirements, and space heating/cooling requirements. Questions such as temperature ranges, amounts, types of fuels consumed, and the prospects for any change in equipment or fuel usage patterns were asked. Responses obtained from the inquiries of these questionnaires were used to form criteria and a framework for the final questionnaire. Figure 8-2 shows the final questionnaire as it was sent to prospective respondents.

GEOPRESSURED-GEOTHERMAL SURVEY

I. INFORMATION LEVEL

A. How much have you heard about geothermal energy along the Gulf Coast? (circle one)

1. nothing 2. very little 3. some 4. a good deal 5. a great deal

B. Are you aware that a geopressured-geothermal test well is currently being drilled in Brazoria County, Texas? (circle one)

1. yes 2. no

II. GENERAL CHARACTERISTICS OF YOUR FIRM

A. What does your firm produce (or what service does it provide)? _____

B. In what county is your firm located? _____

C. Approximately how many people does your firm employ at this location? _____

D. Please indicate below which of your firm's products or services require some low and medium temperature (below 350°F) process heat and contribute significantly to your yearly energy usage.

E. What was your approximate output of each of the products or services listed, during the most recent year for which you have records? (please be explicit about the units of measurement)

product/services

units of output

F. Please indicate the primary fuel which your firm currently uses for the purposes listed to the left below. (circle a number)

	gas	oil	coal	butane	propane	electricity	purchased steam	other
1. low and medium temperature process heating	1	2	3	4	5	6	7	8
2. process chilling	1	2	3	4	5	6	7	8

G. As your firm expands and modernizes during the next 15 years, what fuel do you anticipate using for the purposes listed to the left below? (circle a number)

	gas	oil	coal	butane	propane	electricity	purchased steam	geothermal	other
1. low and medium temperature process heating	1	2	3	4	5	6	7	8	9
2. process chilling	1	2	3	4	5	6	7	8	9

H. Please estimate below what percentage of the equipment you use for process chill and low or medium temperature process heat will, in 8 years and 15 years be equipment which is not in your plant today (i.e., what percentage of the relevant process equipment at those times will have been installed after 1979)? (circle a percentage)

In 8 years (1987)

	10% or less	20%	30%	40%	50%	70%	90%
1. low or medium temperature process heat							
2. process chill							

In 15 years (1994)

	10% or less	20%	30%	40%	50%	70%	90%
3. low or medium temperature process heat							
4. process chill							

I. Do you currently have at your plant significant quantities of heat below 350°F which you are unable to economically utilize?

1. yes 2. no

Figure 8-2: SURVEY QUESTIONNAIRE

III. INFLUENCES ON PLANNING

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- A. When your firm plans to meet future process heating and chilling needs, how significant, from insignificant (1) to very significant (7), are the following factors?

	insignificant						very significant
1. initial equipment cost	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
2. equipment maintenance cost	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
3. fuel cost	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
4. environmental factors	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
5. equipment safety	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
6. favorable public image	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
7. reliability of fuel supply	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
8. simplicity of operation	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>

- B. If your firm were to decide to meet some future energy needs with geothermal energy, how desirable, from very undesirable (1) to very desirable (7), would each of the following supply arrangements be?

	very undesirable						very desirable
1. buy from an existing utility company	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
2. buy from an oil company	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
3. buy from a private company established to sell geothermal water (including an industrial park developer)	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
4. buy from a federal agency	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
5. buy from a state agency	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
6. buy from a local governmental unit	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>
7. drill a well yourself or in cooperation with other firms	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>

- C. If geothermal brine at temperatures up to 350°F were made available at your plant site today at the Btu equivalent price of your current process heat or chill fuel, how much would each of the following possibilities encourage you to convert appropriate processes to utilize geothermal energy? (1=no encouragement, 5=very great encouragement)

	no encouragement				very great encouragement
1. a special federal income tax credit equal to 10% of the capitalized cost of conversion (full carry-over, not subject to preference tax)	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
2. a current federal income tax deduction equal to the remaining depreciable value of the process equipment from which conversion is planned (less salvage, not subject to preference tax)	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
3. a government guaranty of loans which finance conversion to geothermal process heating or chilling	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
4. a 50% government subsidy (cost sharing) of the equipment cost of conversion	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
5. a provision for 20-year insurance against losses which arise because of interruption or termination of geothermal brine supply	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
6. the successful application in a commercial facility of geothermal energy to meet needs similar to your own	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>

IV. FURTHER PARTICIPATION

- A. Would you like us to send you some literature on geopressured-geothermal energy? 1. yes 2. no
- B. Would you like to receive notice of the Fourth Geopressured-Geothermal Energy Conference, which will be held in Austin this fall? 1. yes 2. no
- C. If you have any comments concerning this survey, please make them below or on additional sheets.

TABLE 8-6
POTENTIAL PROCESS HEAT MARKET AND SURVEY SIZE

<u>SIC Number</u>	<u>SIC Group Name</u>	<u>Establishments in Region</u>	<u>Respondents</u>	<u>Response Rate</u>
20	Food and Kindred Products	158	63	39.9%
26	Paper and Allied Products	17	8	47.1
28	Chemicals and Allied Products	104	59	56.7
29	Petroleum Refining	48	27	56.3
32	Stone, Glass and Clay	45	19	42.2
*	Other SIC's	219	91	41.6
	Total	591	267	45.2

* SIC #13, 14, 22, 24, 25, 27, 30, 37.

The study's first objective, to delineate the size of the potential market for the thermal or combined thermal and gas component, was largely addressed by questions II E through I. The second objective, to determine the factors which are important to members of this potential market in their choice of fuel in general and of the geopressured-geothermal fuel in particular, was approached by all the questions in Section III of the questionnaire. The remaining questions in Sections I and II (A-D) served mainly to identify the respondent.

The survey questionnaire was mailed to 591 prospective respondents with a cover letter explaining the reasons for and importance of the survey. The prospective respondents were given approximately ten days to return the questionnaire in an enclosed, addressed, postage-paid envelope before a second wave of questionnaires accompanied by a follow-up request letter was sent. The resulting over-all response rate was 45.2 percent, which is well above the average return rate for mailout questionnaires. Naturally, individual SIC response rates varied. These totals are shown in Table 8-6.

C.2(c) The Data Set. The resulting data set consisted of 267 usable questionnaires, with slight answer rate deviations on some questions. Table 8-7 details the total number of responses by county within major SMSA's. These responses are highly correlated to major metropolitan areas.

C.3. Analysis

Table 8-8 summarizes the dimensions of the market for low-grade industrial heat in the Gulf Coast region.

Over three-fourths of the respondents indicated that currently natural gas was the major source of fuel. As Table 8-8 shows, natural gas will continue to dominate over a fifteen-year horizon, with some shift anticipated to fuel oil and coal. Thus, there exists among the respondents a demand for the methane component of the resource, and some expressed desire to substitute other forms of energy over the long run. Methane, of course, can be obtained from sources other than geopressured reservoirs, so that the use of the combined thermal-methane components would have to prove its commercial feasibility to obtain an important ranking as a substitute fuel. Explicit consideration of geopressured brine as a future fuel source is limited by the respon-

TABLE 8-7
RESPONSES BY MAJOR SMSA

<u>SMSA</u>	<u>Counties</u>	<u>Number of Firms</u>	<u>Percent of Total</u>
Beaumont/Orange/Port Arthur:			12.8
	Hardin	4	
	Orange	9	
	Jefferson	21	
Brownsville/Harlingen/San Benito:			4.9
	Cameron	13	
Corpus Christi:			10.1
	Nueces	23	
	San Patricio	4	
Galveston/Texas City:			3.4
	Galveston	9	
Houston:			51.6
	Harris	109	
	Brazoria	16	
	Fort Bend	4	
	Montgomery	2	
	Liberty	3	
	Waller	4	
McAllen/Pharr/Edinburg:			5.6
	Hidalgo	15	
Not in a Major SMSA:			
	Calhoun	3	1.1
	Colorado	4	1.5
	DeWitt	4	1.5
	Jasper	6	2.2
	Live Oak	5	1.9
	Matagorda	7	2.6
	San Jacinto	1	.4
	Willacy	1	.4
		267	100.0

dents' knowledge of the resource; over half knew "nothing" to "very little" about the resource and had not heard of the well-publicized geopressured-geothermal test well in Brazoria County, an area near Houston in which a majority of the sample have major facilities.

Demand for energy from geopressured-geothermal resources among respondents is limited by two factors: (1) less than one-third of the sample will replace more than 30 percent of their process heat equipment over the next fifteen years; and (2) 30.8 percent of the sample had existing excess low-grade heat not currently used in their facilities. It is unlikely that firms with excess heat would soon provide a market for the thermal component of the resource. The excess heat percentages vary significantly among industry groups, however. Few of the paper and concrete firms have excess heat in-plant, but almost half of those in the chemical and refining groups possess excess heat.

Having defined the market and examined the potential demand by respondents in this market for the sort of fuel provided by the geopressured-geothermal energy, the next step was to identify the elements which would influence this market's participation in development of the resource. These elements were grouped under Section III in the questionnaire. Respondents were to grade these elements grouped into three sets: (1) factors which influence choice of heating and chilling equipment generally; (2) institutional supply arrangements through which the firms might obtain a resource; and (3) patterns of government incentives which might encourage use of the resource.

TABLE 8-8
FUEL USE, EQUIPMENT NEEDS, AND EXCESS HEAT FOR PROCESS HEAT USERS
(percentage of respondents)

SIC Group	Current Fuel				Future Fuel				Replacement of 30 % or More Equipment in 15 Years	Excess Heat in Plant
	Methane	Oil	Coal	Elec.	Methane	Oil	Coal	Elec.		
Food (20)	38.7	1.9	0	5.7	86.8	3.8	0	3.8	34.8	32.1
Paper (26)	66.7	0.2	0	16.7	50.0	0	16.7	16.7	40.0	16.7
Chemicals (28)	77.7	6.1	0	0	62.0	16.0	4.0	4.0	45.5	41.8
Refining (29)	87.0	4.3	0	0	65.2	26.1	0	0	31.8	45.8
Concrete (32)	55.6	0	11.1	11.1	*62.5	0	12.5	0	28.6	16.7
All Respondents	76.3	4.1	0.5	10.3	67.7	10.4	2.1	10.9	32.5	30.8

* Percentage change from current to future fuel reflects only a change in number of responses.

To obtain a ranking of factors influencing equipment choice, survey respondents were asked to rank eight potential factors on an interval scale of one to seven, from "insignificant" to "very significant." Survey responses to these factors were then subjected to a statistical cluster analysis, which groups factors that exhibit similar patterns of responses. Possessing intuitive appeal, these groups were used in the statistical T-test as described above. The results are presented in Table 8-9.

The most important factor for the total sample, and for each individual industry group as evidenced by group means, is fuel cost and supply reliability. Some industry groups exhibited no statistically significant difference (at the .05 level) between this factor and others but, except for chemicals, this was primarily due to the small size of the sample. Given the small size of the corresponding population, the evidence provided by the means is sufficient for descriptive generalization. Environmental factors and equipment safety, and initial equipment cost and maintenance shared a ranking of second for the sample as a whole, while the last two factors fell in a distinct third and fourth. The table shows there to be no significant difference among industry groups in their relative rankings of factors affecting equipment choice. The importance placed upon fuel cost and reliability of supply emphasizes that the size of the geopressured-geothermal reservoir, which largely determines its life and costs per unit of energy produced, will be an extremely important parameter to resolve before the resource will become a commercially acceptable alternative to more conventional fuel sources.

Respondents were also asked to rank on a one-to-seven scale from "very undesirable" to "very desirable" seven institutional supply arrangements. The cluster analysis of their responses, reducing the arrangements to four, provided some very interesting groupings. Local and state governmental agencies were grouped, and then regrouped with federal agencies, to provide one composite institutional arrangement of government-agency supply (which was then the least-preferred of all arrangements). Oil companies and utilities were also grouped together and showed a similar, though statistically less-significant, relationship with geothermal companies. These institutional arrangements and their corresponding rankings are shown in Table 8-10.

Geothermal companies (none of which currently exists on the Gulf Coast, but which could include an industrial park developer), oil companies, and utilities are the preferred suppliers of geothermal energy to survey respondents. Next most desirable was direct participation by the user in drilling a well. A statistically significant

TABLE 8-9
FACTORS AFFECTING EQUIPMENT CHOICE
(mean values and significant* rankings)

<u>Factor</u>	<u>Total Sample</u>	<u>Food</u>	<u>Paper</u>	<u>Chemicals</u>	<u>Refining</u>	<u>Concrete</u>
Fuel Cost and Supply Reliability	4.6 (1)	5.5 (1)	4.6 (1)	5.8 (1)	5.8 (1)	3.2 (1)
Environment and Equipment Safety	4.3 (2)	4.9 (2)	4.2 (1)	5.8 (1)	5.4 (1)	2.8 (1)
Initial Cost and Maintenance	4.2 (2)	5.1 (2)	4.7 (1)	5.4 (2)	5.1 (1)	2.9 (1)
Simplicity of Operation	3.9 (3)	5.0 (2)	4.5 (1)	4.6 (3)	4.3 (2)	3.0 (1)
Public Image	3.6 (4)	4.2 (3)	2.6 (2)	4.6 (3)	4.1 (2)	2.6 (1)

* Differences in ranking of factors indicate a difference between the mean values of the group at the 0.05 level of significance.

difference was evident in all groups (except for paper product firms, with a sample size of eight) between that unorthodox option and the least-preferred alternative of government supply of the resource.

The set of preferred incentives to encourage participation in geopressured-geothermal development singled out successful application of this resource in commercial facilities as giving the most encouragement. Table 8-11 displays the rankings for the collapsed group of factors, ranked on a five-internal scale. This follows logically from the uncertainty surrounding major parameters of the resource and the stated emphasis by respondents on fuel reliability. The fuel reliability factor is also evident in the second most-preferred incentive, 20-year reservoir insurance. Accelerated depreciation on property abandoned for conversion and tax credits for new process equipment clustered to make up the third-preferred incentive package. Government loan guarantees and cost-sharing clustered as the least-preferred package; these two involve the highest degree of government participation and, therefore, their low incentive value is probably due to the same perceptions which caused the "undesirable" ranking respondents accorded governmental supply arrangements. Industry groups exhibit different patterns of incentive preferences, though the relative rankings do not change. Chemicals differentiate between each incentive, the food group ranks the first factor above the other three, and the refineries rank the last three together as less desirable than successful application. These differences in preferred incentive patterns may be useful for the design of incentives to stimulate the participation of one industry group or the other.

C.4. Conclusion

These survey results indicate the geopressured-geothermal resource, if it is to be a commercially acceptable alternative for current users of low-grade process heat, must be available in sufficient quantity to provide a reliable and reasonably priced source of fuel. Because of uncertainty surrounding many key parameters of the resource, successful commercial demonstration will most quickly stimulate industry participation. Moreover, the thermal component will probably prove commercially viable for process heat applications only if used in conjunction with the methane; based on current perceptions, the great majority of respondents in the region plan to continue using methane to meet their heating and chilling needs. The government's role in stimulation of resource development should be indirect after the testing and demonstration phase, for not only are government agencies considered undesirable suppliers, but incentives involving a high degree of government participation are not viewed as providing encouragement.

TABLE 8-10
PREFERRED INSTITUTION SUPPLYING GEOPRESSURED/GEOTHERMAL RESOURCE
(mean values and significant* rankings)

<u>Institution</u>	<u>Total Sample</u>	<u>Food</u>	<u>Paper</u>	<u>Chemicals</u>	<u>Refining</u>	<u>Concrete</u>
Geothermal Company	3.2 (1)	3.9 (1)	3.3 (1)	4.0 (1)	4.3 (1)	1.7 (1)
Oil Company or Utility	3.1 (1)	3.6 (1)	3.0 (1)	3.9 (1)	4.0 (1)	2.3 (1)
Participation in Drilling	2.3 (2)	2.7 (2)	2.4 (1)	2.8 (2)	3.0 (2)	1.0 (1)
Government Agency	1.5 (3)	2.0 (3)	1.3 (1)	1.9 (3)	1.7 (3)	0.6 (2)

* Differences in ranking of factors indicate a difference between the mean values of the group at the 0.05 level of significance.

TABLE 8-11
PREFERRED INCENTIVES TO ENCOURAGE PARTICIPATION IN
GEOPRESSURED/GEOTHERMAL DEVELOPMENT
(mean values and significant* rankings)

<u>Incentive</u>	<u>Total Sample</u>	<u>Food</u>	<u>Paper</u>	<u>Chemicals</u>	<u>Refining</u>	<u>Concrete</u>
Successful Commercial Application	2.5 (1)	3.2 (1)	2.5 (1)	3.0 (1)	3.1 (1)	1.3 (1)
Reservoir Insurance	2.1 (2)	2.9 (2)	2.1 (1)	2.3 (2)	2.3 (2)	1.5 (1)
Tax Credit and Deduction	2.0 (2)	2.7 (2)	1.9 (1)	2.2 (3)	2.4 (2)	1.2 (1)
Government Loan Guarantee and Subsidy	1.8 (3)	2.7 (2)	1.7 (1)	1.8 (4)	2.3 (2)	1.0 (1)

* Differences in ranking of factors indicate a difference between the mean values of the group at the 0.05 level of significance.

CHAPTER IX

CURRENT GOVERNMENT INCENTIVES BEARING ON GEOPRESSURED-GEOTHERMAL DEVELOPMENT

A. INTRODUCTION

A number of incentives have been undertaken by the federal government in recent years to stimulate geothermal development. The sponsors of most of these incentives were principally concerned with development of hydrothermal resources such as are found in the western states. Consequently, though the incentives may well be available to developers of the thermal and kinetic components of geopressured reservoirs, the statutory-regulatory language and history of the incentives reflect primarily the concerns of the sponsors and, therefore, raise questions about the application of those incentives to a geopressured development project. This chapter reviews existing geothermal incentives and elaborates on their applicability to geopressured development projects where questions of that nature arise.

The national energy legislation of 1978 and its subsequent regulatory implementation also provide various important incentives to stimulate geopressured methane production. Potentially the most significant of these is the Economic Regulatory Administration's decision to allow the burning of geopressured methane in boilers which would otherwise be prohibited from burning natural gas. This and other incentives which stimulate geopressured methane production are also elaborated on in this chapter.

The Geothermal Loan Guaranty Program is discussed first; then, DOE's support of geopressured R and D programs is (briefly) discussed; then, federal tax incentives; then, geopressured methane price and use incentives and dis-incentives; and, finally, regulatory dis-incentives to the non-utility generation of electricity or remote transportation of geopressured methane are discussed.

B. GEOTHERMAL LOAN GUARANTY PROGRAM

The Geothermal Loan Guaranty Program (GLGP) operates under regulations promulgated by the Department of Energy (10 C.F.R. Part 790). The regulations are currently (September, 1979) being revised to reflect 1978 statutory amendments.

Subject to certain limitations, the GLGP will guarantee 75% of the cost of a geothermal project. A geothermal "project" is any undertaking which develops in an environmentally acceptable manner "geothermal resources" for which a market potentially exists. The "project" definition is broad and includes exploration efforts, power plants, process heat facilities, etc.

"Geopressured fluids" and "byproducts derived from them" are specifically included in the "geothermal resources" definition of current and proposed regulations (10 CFR 790.5). Presumably, "geopressured fluids" encompasses liquid and gaseous water, and natural gas. If the natural gas is not considered a fluid, there is some question as to whether it would be considered a byproduct because the byproduct definition is limited to "minerals or gases" which have a value of less than 75% of the value of the "steam and associated geothermal resource" and which are not of sufficient value to warrant their extraction and production without producing the geothermal resource. Obviously, if the geopressured methane in geopressured-geothermal reservoirs were not held to be a "geopressured fluid", it may well be too valuable to constitute a "byproduct" and, hence, the Geothermal Loan Guaranty Program may not now be available to help finance projects which arise principally to develop the geopressured methane.

The "Omnibus Geothermal Energy Commercialization Act of 1979" (Senate Bill 1388), currently in committee, contains language which addresses the 75% byproduct value limitation to clarify that that percentage is of the value of the total resource, not merely of the "steam and associated geothermal" resource.

The program has not been used to date for development for geopressured-geothermal projects. It has not been particularly successful in the financing of more conventional geothermal projects in the western states, either; this is in part because of delays

in approval of loan guaranty applications and the relatively low \$25,000,000 guaranty ceiling, both of which are now being corrected.* A continuing problem of the program is that it does little to reduce the financial risk to the principal obligor on the loan, who may avoid this obligation as a practical matter only if the loan is declared to be in default; because of indentures in other outstanding loans and because they anticipate future reliance on debt markets, very few firms can tolerate the damage which would flow from having once been declared in default on a loan obligation.

Senate Bill 1388 would also establish a direct federal loan program to operate through September, 1986, for developers who would explore for, or confirm the economic viability of, a geothermal energy reservoir. If the reservoir were shown to be unacceptable for commercial development, the Secretary of the Department of Energy could cancel the unpaid balance and any interest due on the loan. Senate Bill 1388 would limit any one loan to \$3,000,000 or 50% of the exploration and confirmation project costs, whichever proved to be less. The percentage ceiling is 90% for projects which would ultimately apply the resource to space or process heating or cooling in facilities built or under construction.

The impact of a forgivable loan program such as contemplated by Senate Bill 1388 on geopressured-geothermal development is likely not to be significant until more knowledge is developed about how to "confirm" a reservoir's economic viability; also, the standards of the investment community and rating firms are rather Byzantine and may not always acknowledge the distinction between a loan "forgiveness" and a loan "default."

C. DOE AND STATE SUPPORT OF GEOPRESSURED-GEOTHERMAL R, D, AND D PROJECTS

Both DOE (ERDA and AEC) and the Texas Energy Advisory Council (now, Texas Energy and Natural Resources Advisory Council) have contributed funds to support geopressured-geothermal research and development projects. DOE and its predecessors have funded approximately \$7,000,000 for research at the University of Texas alone; TEAC has contributed some \$50,000 to the UT research program. The share of DGE's budget allocated to geopressured-geothermal research for fiscal 1979 is slightly more than \$27,500,000 and the anticipated share for fiscal year 1980 will be in excess of \$32,000,000. In the immediate future, DOE plans to reduce resource uncertainty for potential developers by financing (1) the drilling of test wells (design wells) and (2) the re-entry of other wells (wells of opportunity) to gather data on the drilling, completion, and production of geopressured-geothermal wells.

It is under the test well program that General Crude Oil Company drilled the geopressured-geothermal well in Brazoria County, Texas. Wells of this nature are each expected to cost in the neighborhood of \$6,000,000. DOE had planned to finance the drilling of five such wells per year, but now believes that four wells per year is a more realistic figure. The other well drilling program, the wells of opportunity program, is the one under which Gruy Federal has acquired abandoned oil and gas wells for entry and work-over in Louisiana. This program currently calls for the re-entry of four wells per year at an approximate cost of \$5,000,000 per well. Later, testing of surface equipment such as turbines will provide similar first-hand data on utilization parameters.

Would-be participants in geopressured-geothermal development are almost unanimous in their agreement that programs such as these will be necessary to stimulate commercialization of the resource because current unknowns are so numerous that expected rates of return cannot be calculated with any confidence.

D. FEDERAL TAX INCENTIVES

The Energy Tax Act of 1978 provided a number of federal tax incentives to producers and users of geothermal energy and to producers of geopressured methane. Conventional wisdom is that the geothermal tax incentives are also available to those who produce or use the geothermal component of geopressured-geothermal resources; this may not in fact be the case, depending on how the Internal Revenue Service interprets the language of the Act.

*Louise H. Nasr's 1978 study for DOE, entitled Geothermal Loan Guaranty Program and Its Impact on Exploration and Development, is a thorough and critical evaluation of the program to date; Nasr does not recommend extending the program beyond 1984.

Whether producers and users of the geothermal component of geopressured-geothermal resources may claim the tax benefits allowed by the Energy Tax Act depends on whether Congress intended that its "geothermal deposit" definition encompass deposits which also contain natural gas; there are several indications that this was not Congress' intent. All references to geothermal energy in the Internal Revenue Code (IRC), as amended by the 1978 Tax Act, cite the definition set out in Section 613(e)(3), the pertinent part of which reads as follows:

...the term "geothermal deposit" means a geothermal reservoir consisting of natural heat which is stored in rocks or in a aqueous liquid or vapor (whether or not under pressure). Such deposit shall in no case be treated as a gas well for purposes of this section or Section 613A, and...

Sections 613 and 613A contain the rules for percentage depletion deductions on oil, gas, and geothermal properties.

The first sentence of the definition certainly seems to include the geothermal component of a geopressured reservoir, and the second sentence (if in fact part of the definition) says only that the geothermal component should not be considered a gas "well" for purposes of the depletion deduction. Nonetheless, in three separate comments, the House-Senate conferees on the Energy Tax Act indicated that they intended wells which produce natural gas from geopressured brine to be "gas" wells. Concerning intangible drilling cost deductions, their report, Section 37, said: "The conference agreement does not change present law with respect to wells producing natural gas from geopressured brine, so that these will continue to be treated as natural gas wells for purposes of the IDC election." Concerning minimum tax treatment, the conferees said, at Section 38,: "Thus, income and deductions from wells producing natural gas from geopressured brine will continue to be aggregated with income and deductions from all oil and gas property for purposes of the related income offset under the minimum tax." Finally, concerning the recapture of IDC deductions, they said, at Section 39,: "However, geopressured natural gas wells are to be treated as gas wells as under present law." It is also troublesome that the conferees at no time referred to the problem of keeping separate accounts for expenses related to geopressured-geothermal development and use, on the one hand, and geopressured natural gas development and use, on the other. Too, the fact that the conferees rejected the generally separate treatment accorded geopressured-geothermal deposits in the House version of the bill may be argued to reflect an intent to treat those deposits as gas deposits. Despite these unfortunate ambiguities, the following explanation assumes the geothermal definition includes the geothermal component of the geopressured resource.

D. 1. Tax Incentives Applicable to Geothermal Energy in General

A new Section 44C of the IRC provides a residential tax credit for investment, including labor expenses, in renewable energy source property. The term "renewable energy source property" specifically includes property installed in connection with a dwelling and which transmits or uses energy derived from 613(e)(3) geothermal deposits. The credit is 30% of the first \$2,000 and 20% of the next \$8,000 expended for renewable energy source property each year. The credit applies only to expenditures made before January 1, 1986. The credit is available in addition to the 10% credit which is available for the purchase of depreciable business property in general and the credit may be carried forward for use in future tax years through 1987. The impact of this residential energy credit on geopressured-geothermal development will apparently be negligible because residential use of this resource is probably more remote than 1985.

The Energy Tax Act also amended IRC Section 48 to provide for a business tax credit for investment in "energy property". Energy property is defined to be any of six categories of property, two of which are related to utilization of geothermal energy. The credit (generally, 10%) allowed on these expenditures is in addition to the standard 10% investment tax credit and may be claimed for expenditures on property for which construction is completed by the taxpayer after September 30, 1978, or with respect to new energy property only, which is acquired by the taxpayer after that date. This credit may only be claimed on tax returns through the year ending December 31, 1982, too short a term to much affect geopressured-geothermal development.

Section 48(1)(3) defines one of the categories of energy property, "alternative energy property", to mean equipment used to produce, distribute, or use energy derived from a 613(e)(3) geothermal deposit. Alternative energy property does not include property used predominately in a "utility" business, if the utility's rates

are approved by a political subdivision of any state or the United States. This exclusion unfortunately means that alternative energy property tax credits will not be available to electric utilities or gas transmission or distribution companies directly. The loss of this credit would probably be the most serious consequence of an IRS interpretation of the geothermal deposit definition which excluded the thermal component of geopressured reservoirs.

Section 48(1)(5) defines the other relevant category of energy property, "specially defined energy property". This category includes, among other things, a heat exchanger or a preheater and therefore appears intended to stimulate geothermal process heat applications. Specially defined energy property must be used to reduce the amount of energy consumed in an existing (October 1, 1978) industrial or commercial process in an existing facility. Unlike alternative energy property, specially defined energy property includes public utility property.

Though these two credits may not be carried forward, they may be used to offset up to 100% of tax liability.

The producer of a 613(e)(3) geothermal deposit may now elect to (1) deduct as a current business expense his intangible drilling and development costs (IDC's) or (2) capitalize those costs and add them to the basis of the property for recovery through depletion or depreciation. The word "property" is a word of art (Section 614), but generally refers to the aggregate of an operator's working interests in a geothermal deposit, as long as they are located on a single parcel or tract of land, or are produced as a unit.

Subsection (e) was added to IRC Section 613 and provides for an elective percentage depletion deduction for geothermal producers and defines what a geothermal deposit is. The definition is the one previously quoted. The deduction allowed is a percentage of the gross income from the geothermal property. The percentage is 22% through taxable years beginning in 1980 and is gradually decreased to 15% for taxable years beginning in 1984 and thereafter. Cumulative depletion deductions may exceed the cost of the property.

Portions of both the IDC deduction and the percentage depletion deduction may be treated as items of tax preference (ITP's) subject to levy of the minimum tax. Geothermal IDC's become ITP's to the extent that the IDC's which were claimed on all geothermal properties in excess of the amounts which could have been claimed under the capitalization and ten-year depreciation methods exceed the net income which the taxpayer realizes from all geothermal properties during the tax year. This is an extremely complicated area of tax law, but it obviously could work to lessen the IDC incentive for a geothermal developer who, at least in early years, may have IDC's which are well in excess of his net income from geothermal properties. Corporations, other than Subchapter S Corporations and personal holding corporations, are not subject to the IDC minimum tax. As to percentage depletion deductions, these become ITP's as soon as their cumulative total on a property exceeds the taxpayer's basis (costs) in the property.

If a geothermal property on which IDC's have been claimed is sold, the federal government will recapture (by attributing to the ordinary income of the taxpayer) the difference between the aggregate money amount actually deducted as IDC's and the amount which could have been deducted had the IDC's been capitalized and depreciated as part of the basis of the property. This section highlights the apparent need of a geopressured-geothermal producer to keep separate accounts which reflect the expenses which should be attributed to the geothermal resource, on one hand, and the geopressured methane resource, on the other. He needs to do this so that the appropriate amount of recapture may be calculated should he sell only one part of the energy-producing property.

Another IDC limitation concerns the "at risk" ceiling on losses which may be deducted if incurred in exploring for, or exploiting, geothermal deposits. The at risk limitation applies to individuals and closely held corporations and provides that they may not claim as deductions related to exploring for, or exploiting, geothermal deposits amounts in any year which are in excess of income from those activities, unless they (the taxpayers) are actually at risk for the excess amounts at the end of the year. Subsection (b)(4) of Section 465 provides that "a taxpayer shall not be considered at risk with respect to amounts protected against loss through nonrecourse financing, guaranties..., or similar arrangements;" this indicates that money borrowed under the GLGP likely will not be considered an amount at risk against which a taxpayer may claim geothermal deductions in excess of income.

Concerning the percentage depletion deduction available for geothermal producers, it is not limited to 65% of overall taxable income or to taxpayers who are not integrated oil companies, but it is subject to the limitation that it not exceed 50% of the taxable income from the geothermal property on which it is claimed. This latter restriction may eliminate the percentage depletion deduction in the first year of production when IDC's lower taxable income. However, the availability of long-term percentage depletion on geothermal properties probably makes those properties particularly attractive to integrated oil companies, which no longer enjoy a similar deduction on most oil and gas properties.

D. 2. Tax Incentives Applicable to Geopressured Methane

The Energy Tax Act also included a couple of tax incentives for producers of the geopressured natural gas portion of the geopressured-geothermal resource. The first of these is an additional investment credit of 10% on expenditures for "equipment for producing natural gas from geopressured brine" (IRC Section 48 (1)(2)(A) (vi)). The equipment must be used exclusively for this purpose. The credit is available only through December 31, 1982.

For geopressured wells spudded before January 1, 1984, IRC Section 613A has been amended to provide for a yearly deduction equal to 10% of the gross income (less royalties) a taxpayer derives from the sale of natural gas produced from geopressured brine. As long as the well is spudded during that time period, the 10% yearly depletion allowance may be taken for the life of the well.

The 10% depletion allowance is not subject to the 65% of total taxable income limitation or, significantly, to the integrated oil and gas company limitation. However, it is subject to the limitation that it not exceed 50% of the taxable income from the geopressured natural gas property. Cumulative percentage depletion in excess of the taxpayer's basis (costs) in a geopressured natural gas property is an ITP.

IDC's on wells producing natural gas from geopressured brine may be deducted. Excess geopressured natural gas IDC's may also be ITP's; as noted in the discussion of the geothermal deposit definition, however, these IDC's are aggregated with IDC's from other oil and gas properties, thereby lessening their potential for treatment under minimum tax provisions.

D. 3. Miscellaneous Tax Provisions

The Energy Tax Act also amended IRC Section 48(a) to provide that no investment credits be allowed for expenditures on oil or gas boilers used in conjunction with manufacturing, processing, or mining facilities unless environmental regulations preclude the use of coal-fired boilers. "Mining" does not include oil or gas operations. IRC Section 167(p) was amended to provide that oil and gas boilers which are ineligible for investment tax credits are also ineligible for any form of rapid depreciation. IRC Section 167(p) was likewise amended to encourage early abandonment of oil or gas boilers or other combustors by providing that they may be straightline depreciated as though their useful lives terminated on the date scheduled for abandonment. These provisions obviously do nothing to help the market for geopressured natural gas, but they could stimulate interest in use of the geothermal component of the resource.

E. GEOPRESSURED METHANE PRICE AND USE INCENTIVES AND DISINCENTIVES

Since 1954, the wellhead price of all natural gas sold in the interstate market has been subject to federal price regulation. Section 121 of the Natural Gas Policy Act (NGPA) provides that by no later than November 9, 1979, the first sale price of various categories of "high-cost" gas will cease to be controlled by the federal government. Subsection 107(c) defines high-cost natural gas to include gas which is produced from geopressured brine. The absence of federal price regulation on this natural gas will presumably encourage producers to develop the resource. (Under Subsection 107(d) of the NGPA, a producer would be put to an election between unregulated prices and any future tax incentives which might be allowed for the production of natural gas from geopressured brine.)

Natural gas from geopressured brine is also subject to the incremental pricing provisions of the NGPA. Under these provisions, interstate transmission companies are required to pass on to certain (mostly, industrial) customers so much of the first sale purchase price of natural gas from geopressured brines as is in excess of the "incremental pricing threshold". The differential may not be passed through to institutions or electric utilities and the FERC may provide exemptions for industrial cogenerators. The incremental pricing differential paid by the end user may not rise so high that the burner tip cost of natural gas exceeds the "burner tip" cost of the cheapest appropriate alternate fuel.

The incremental pricing threshold for natural gas from geopressured methane is 130% of the Btu equivalent price of a barrel of #2 fuel oil landed in New York City during the preceding month; thus, if the landed price of #2 fuel oil in New York City is \$23.00 per barrel, first sale gas acquisition costs in excess of \$5.34 per mcf would be borne by the specified industrial users.

The incremental pricing provisions obviously have the potential to act as a disincentive to the production of natural gas from geopressured brine, but this is not thought likely to occur because the burner tip cost of appropriate alternate fuels is expected to be about at or below the incremental pricing threshold, plus transportation costs, anyway.

The Power Plant and Industrial Fuel Use Act (FUA) of 1978 contains restrictions on the future use of natural gas in certain boilers, gas turbines, internal combustion engines, or combined cycle units. In general, the restrictions prohibit the building of new gas-fired boilers, etc., and require that existing ones be retired by 1990. The Economic Regulatory Administration has ruled (10 CFR 507.3(e)(1), 44 FR 28950) that gas produced from geopressured brine from wells spudded prior to January 1, 1990, is not natural gas for purposes of the Fuel Use Act and, hence, that boilers, etc., which burn this geopressured methane may be built, or need not be retired, as the case may be. The ERA's definition could have a tremendous positive impact on geopressured-geothermal development by creating an instant market for geopressured methane. There is at least a huge inventory of boilers, etc., in place which industry would prefer not to prematurely retire. Implementation of other exemptions potentially available under the FUA will largely determine the extent to which the ERA's definition in fact promotes geopressured-geothermal development.

F. MISCELLANEOUS REGULATORY CONSIDERATIONS

The Public Utility Regulatory Policies Act of 1978 (PURPA) contained several provisions which may help geothermal development in western states, but which are unlikely to much affect development of geopressured-geothermal resources. These have to do with inter-connection and wheeling orders for the transmission of electricity and exemptions for non-utilities from the Public Utility Holding Company Act and other utility regulation.

PURPA added a new Section 210 to the Federal Power Act which provides that a qualifying cogenerator or small power producer may petition the FERC for an order requiring the interconnection of the applicant's facility with transmission facilities of any electric utility. The FERC was also empowered to order the sale or exchange of electricity between a qualifying cogenerator or small power producer and any electric utility. These provisions might be helpful to a non-utility which contemplated generation of excess electricity from geopressured reservoirs. Unfortunately, a small power producer must rely on biomass, waste, or renewable resources for fuel, and geopressured-geothermal resources have only a tenuous claim to being renewable. If the developer enhanced the brine temperature with the methane, generated electricity, and used the heat effluent in process applications, the developer would normally qualify for co-generation status.

PURPA also added a new section to the Federal Power Act which provides that any electric utility may petition the FERC to order any other electric utility to wheel power for the applicant from one site to another over the electric transmission grid of the other utility. This could encourage electric utilities to develop geopressured-geothermal resources which lie outside their service areas. A provision of this nature for non-utilities would also be appropriate (from a developer's perspective).

Texas intrastate electricity generation and transmission has historically been outside the jurisdiction of the FERC. It is mostly governed by an intricate set of mutual agreements among utility members of the Electric Reliability Council of

Texas. Therefore, non-utility generators of electricity should expect little help from the FERC regarding intrastate electricity transactions and may expect organizational problems dealing with ERCOT members directly.

PURPA also provided that certain small power producers (those with a production capacity of 30 megawatts or less) and qualifying cogenerators shall be exempt, under rules promulgated by the FERC, from all or part of the Public Utility Holding Company Act and other state or federal laws respecting the rates of electric utilities. This provision could be important to a non-utility co-generator, such as a petrochemical plant, which wanted to generate electricity for predominately in-house use and did not want to fall subject to utility regulation. The provision might also be attractive to a company which, but for the provision, would be classified as a public utility and therefore be denied the tax credit on alternative energy property.

Large natural gas consumers who would develop geopressured reservoirs as fuel or feedstock sources may encounter difficulty in transporting that gas from the reservoir sites to their plant locations. These consumers would prefer not to lose title to the geopressured methane during its transport because, if they did, its delivery could then be curtailed by the transporting pipeline during periods of gas shortage. However, the FERC does not now issue certificates of public convenience and necessity for interstate pipelines to transport user-owned gas supplies on a long-term basis. PURPA added a subsection to 7(c) of the Natural Gas Act of 1938 which would authorize long-term certification of user-owned gas transport for "high priority uses;" regulations under this authorization are still being implemented, but might reasonably extend to feedstock gas for industry. As to Texas intrastate transport, the Texas Railroad Commission can order common carrier pipelines to transport gas for anyone, and can order non-common carrier pipelines to carry gas owned by other gas utilities (Texas Attorney General Opinion No. H-830, 1976). The potential problems, therefore, appear less as to intrastate transport, especially given the historically lesser chance of curtailment intrastate.

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CHAPTER X

SIX PROFILES FOR UTILIZATION OF THE GEOPRESSURED-GEOTHERMAL
RESOURCE IN THE MID-TERM

A. INTRODUCTION

If the geopressured-geothermal resource along the Texas Gulf Coast is one day developed commercially, the types of firms which participate in that development will be influenced by, among other factors, the parameters of the reservoirs they may expect to encounter and the legal constraints and incentives which bear on resource development. This chapter develops profiles which describe probable combinations of firm types and resource development schemes in the mid-term (i.e., at the time firms in the private sector are beginning to put their money, not DOE's, at risk to finance development). This chapter presents the four mid-term profiles which seem most likely to occur; these could perhaps exist simultaneously at different reservoirs during the mid-term. For reasons explained in the next section, none of the most likely profiles includes use of the resource for utility electricity generation. However, because of the extreme uncertainty about important reservoir parameters and the fact that the energy incentive framework is very much in flux, it would be imprudent to disregard altogether the possibility of utility electricity generation at this time. Therefore, this chapter also presents two electricity generation profiles which, though not seen as probable, are seen as the least improbable of those which might occur.

B. BACKGROUND AND ASSUMPTIONS

The incentive framework peculiar to geopressured-geothermal energy is examined in detail in Chapter IX. Table 10-1 characterizes that framework in abbreviated terms; this chapter's profiles are premised on continuation though the mid-term of that framework.

TABLE 10-1

PROFILE LEGAL PARAMETERS

- ERA continues geopressured methane exemption from prohibitions of Fuel Use Act of 1978. 10 C.F.R. 507.3(e)(1)
- Geopressured methane is not subject to wellhead price controls. NGPA 121(b)
- First sale acquisition costs of geopressured methane in excess of incremental pricing threshold must be passed by interstate transmission companies to industrial end-users. NGPA 201 & 202
- NGA 7(c)(2) allows FERC to certify transport of user-owned natural gas by interstate pipelines for "high-priority uses"
- Unless a non-utility generator of electric power from geopressured-geothermal resources is also a co-generator, it may not expect interconnection orders or exemption from utility regulation. FPA 210. PURPA 210. Non-utilities may not expect wheeling orders. FPA 211
- Geopressured-geothermal resources in Texas must be developed without waste of the thermal component. Texas Natural Resource Code 141.012
- The Texas Railroad Commission has state jurisdiction over disposal of geopressured brines. Texas Water Code 26.131
- There is no mandatory field unitization law in Texas
- Texas courts will hold that geopressured-geothermal resources are mineral resources
- Following federal tax incentives are available to geopressured-geothermal developers (I.R.C. 38, 46, 48, 263, 613, and 613A):
 - Regular 10% credit (utility limitations)
 - Additive 10% credit on geopressured methane production equipment
 - Additive 10% credit on alternative energy property (utility prohibition)
 - Additive 10% credit on specially defined energy property ("existing" limitation)
 - 10% statutory deduction on gross income from sale of geopressured methane (no oil company limitation)
 - 15% statutory deduction on gross income from sale of geothermal component (no oil company limitation)
 - Current deduction of IDC's on geothermal production and deep reinjection wells (minimum tax consequences)

The profiles are constructed on the assumption that incentives, such as the alternative energy property tax credit, which are scheduled to expire in the early 1980's will be extended beyond that time. It is also assumed that a definitive judicial ruling will have been made prior to the mid-term that the geopressured-geothermal resource is a "mineral", as opposed to a "water", resource; the effect of this assumption is that current ambiguity regarding resource ownership is not a consideration influencing the profiles.

The profiles are also premised on developer expectations that geopressured-geothermal reservoirs with characteristics moderately favorable for economic development do exist. Presumably, DOE's well-drilling program will, by the mid-term, have established that such expectations are reasonable. Table 10-2 characterizes in abbreviated terms the reservoir expectations which the profiles assume developers entertain.

TABLE 10-2

PROFILE PHYSICAL PARAMETERS

- On-shore reservoir
- T = 325°F
- Porosity = 20%
- Permeability = 30md
- Methane content = 40scf/bbl
- Well depth = 15,000-17,500 ft.
- Sand thickness = 500 ft.
- Fluid recovery ratio = 5% w/o deep reinjection
- Deep reinjection doubles reservoir life, triples fluid recovery
- Reservoirs produced continuously, flow rates variable

C. DEDUCTIONS AND RATIONALES

Several important considerations, largely deduced from the previously stated assumptions, affect all the profiles. First of these is that reservoirs which are large enough to support economic exploitation will be large in areal extent. A 40,000 bbl/day well would be expected to drain at least 11,300 acres over its 30-year life, based on Table 10-2 assumptions, without reinjection of brine to the producing formation.

Although information on the subject is incomplete, reservoirs which are continuous over that expanse are expected to be rare. As a rule of thumb, deep reinjection (to the producing formation) may be expected to triple fluid recovery over a doubled reservoir life (60 years); its ability to reduce the volume which would be drained in 30 years is not as confidently estimated. The actual relationship between fluid recovery and manner of reinjection will likely be very reservoir-dependent. In developing the profiles, the assumption was that deep reinjection would cut the volume to be drained in 30 years approximately in half (i.e., a 40,000 bbl/day well would drain 5,650 acres in 30 years if spent fluids were re-injected to the producing formation). Each of the four probable profiles is based on a deep reinjection scheme because that maximizes the ratio of fluid recovery to reservoir volume; high fluid recovery obviously enhances development economics, as does minimization of required reservoir size (by reducing risk of reservoir discontinuity, area of possible surface subsidence, and legal and administrative problems related to lease acquisition and management). Deep reinjection should also prevent the occurrence of physical conditions which cause subsidence and militate against contamination by geopressured brines of the disposal environment. Operating costs will be high for either reinjection option.

Pressurization of fluids for deep reinjection is unfortunately thought to consume all the power which can be produced from the geothermal component of the resource; for this reason, the four profiles which appear most probable in the mid-term do not contemplate net electricity generation at the reservoir site. The four profiles assume that none of the methane component will be required to fuel deep reinjection; available evidence is incomplete, but suggests that this assumption will prove optimistic as to at least some reservoirs.

The other two profiles, the utility electricity generation profiles, are premised on power production in hybrid geothermal/methane-fired facilities which would each be fed by three or four wells and produce some 30 MW(e), net of shallow reinjection needs. Table 10-3 shows briefly the calculations on which such a hybrid facility's capacity is based. These calculations, though when summed may understate the aggregate conversion efficiency of the facility, nonetheless result in a capacity figure which is quite optimistic because the flow rate, gas content, and temperature parameters are all at the optimum end of the reasonable spectrum.

TABLE 10-3

HYBRID POWER GENERATION FACILITY CAPACITY

A. ELECTRIC POWER GENERATION (GEOTHERMAL)

$$40,000 \text{ bbl/day} = 585,022 \text{ lb}_m/\text{hr}$$

Inlet Conditions:

$$T = 320^\circ\text{F} \quad p = 2000 \text{ psia} \quad h = 292.5 \text{ Btu/lb}_m$$

Outlet Conditions:

$$T = 180^\circ\text{F} \quad p = 20 \text{ psia} \quad h = 148 \text{ Btu/lb}_m$$

$$\Delta h/\text{lb}_m = 292.5 - 148 = 144.5 \text{ Btu}$$

$$\Delta h/\text{hr} = 144.5 \times 5.85 \times 10^5 = 8.45 \times 10^7 \text{ Btu}$$

$$\text{If conversion efficiency} = 13\%, \text{ then } 8.45 \times 10^7 \times .13 = 1.1 \times 10^7 \text{ Btu/hr}$$

$$1 \text{ kwh} = 3412 \text{ Btu, so } 1.1 \times 10^7 \text{ Btu/hr} = 1.1 \times 10^7 \times \frac{10^{-3}}{3.412} \text{ kw} =$$

$$= 3.22 \text{ Mw(e) (geothermal/well)}$$

B. ELECTRIC POWER GENERATION (GEOPRESSURED METHANE)

$$40,000 \text{ bbl/day} \times 40 \text{ scf/bbl} \times \text{day}/24\text{hr} = 6.67 \times 10^4 \text{ scf/hr}$$

$$6.67 \times 10^4 \text{ scf/hr} = 66.7 \text{ mcf/hr} = 66.7 \times 10^6 \text{ Btu/hr}$$

$$\text{If conversion efficiency} = 40\%, \text{ then } 66.7 \times 10^6 \times .4 = 26.68 \times 10^6 \text{ Btu/hr}$$

$$1 \text{ kwh} = 3412 \text{ Btu, so } 26.68 \times 10^6 \text{ Btu/hr} = 26.68 \times \frac{10^{-3}}{3.412} \times 10^6 \text{ kwe} =$$

$$= 7.82 \text{ Mw(e) (methane/well)}$$

Source: T, p, and h values in "A" are taken from J. S. Wilson, et al, "A Phase '0' Plan for the Production of Electrical Power from Gulf Coast Geopressured-Geothermal Waters," Proceedings: Second Geopressured-Geothermal Energy Conference, Vol. IV (February 1976) Appendix B.

Each profile assumes that the Economic Regulatory Administration's exclusion of geopressured methane from the definition of "natural gas" to which the Fuel Use Act applies is perceived by developers as likely to remain in force throughout the mid-term, and that the prohibitions of the Fuel Use Act itself are perceived as likely to remain in force as well. These assumptions obviously promote a boiler fuel market for high-cost geopressured methane.

At the mid-term, a good deal of uncertainty is presumed to remain regarding the characteristics of any particular reservoir. This suggests, for example, that development projects will be internally funded. Uncertainty regarding reservoir characteristics also militates against the capital commitment involved in new process-heat-using facilities; these would be uneconomical in the absence of significant geopressured methane production and long-term flow of geothermal brine.

The Geothermal Loan Guaranty Program is an element of only one of the profiles, the one in which a project company is the shell entity which secures a loan to develop reservoirs and a surface facility for utility electricity generation. This

is so because it appears that only a shell entity could tolerate the financial consequences, such as lower bond ratings, ancillary to default on even a nonrecourse loan. Further, we do not believe that the loan guaranty would be a requisite to the availability to a major firm of financing for a geopressured-geothermal project.

Had the profiles been constructed in the early 1970's, they would probably have included more joint ventures between oil and gas producers and other parties; however, the energy shortage of the mid-1970's has led many of these other parties to form or purchase their own exploration subsidiaries and, hence, the impetus for joint ventures has been reduced. Also, were Texas courts to decide that geopressured-geothermal resources are not mineral resources, but rather are sui generis, this might bring forth specialized lease brokers or other participants not now included in these profiles.

D. THE PROFILES

D.1. Petrochemical Company: Feedstock and Boiler Fuel

A petrochemical company, through its own production subsidiary or in a joint venture with an oil and gas producer, might elect to develop a geopressured-geothermal reservoir to obtain a more secure source of feedstock and boiler fuel. In this instance, there is a remote possibility that the petrochemical company, a large consumer of electricity, might opt for shallow reinjection, freeing up for "in-plant" use 1/2 to 2/3 of the electrical output of the wellhead generator. There is also a remote option to utilize the demethanized brine for process heat purposes.

The shallow reinjection option is seen as remote primarily for the fluid recovery/reservoir-size and subsidence reasons previously explained. Further, because regulatory provisions on interconnection and wheeling do not apply to a non-utility generating power from a non-renewable resource, the petrochemical company would have no way to economically transmit electricity from the wellhead to one or more distant plants. The sale of excess electrical power might subject the petrochemical firm to utility regulation. ReInjection well costs would presumably be lower, but the danger of clogging of the disposal aquifer would be increased. On the bottom line, if the transportation and other problems were resolved, would be a comparison between the present value of (1) electricity and methane produced over (for example) a 30-year period and (2) methane alone produced in greater quantity over twice such a period; the uncertainties of discounting methane from such an extended future might also favor electricity production.

The process heat option seems improbable mostly because the heat would be of the low-level variety which is currently abundant as effluent in petrochemical facilities. The wellhead and plant would have to be at more or less the same site. Corrosion or scaling problems could be expected to arise, though solutions to these problems might be forthcoming during the mid-term. Alternative energy property tax credits would be available on some equipment, but credits would be available on specially defined energy property, such as heat exchangers, only if the facility and process were "existing" in 1978. Of course, the use of low-grade heat to preheat processes may be expected to become more economical as energy prices continue to rise.

The premise which really drives this profile is that user-owned supplies of methane feedstock and boiler fuel would be relatively secure from curtailment; especially as to feedstock, this would be quite an inducement to a petrochemical firm's participation. Petroleum refiners or firms producing food and kindred products were not accorded central roles in this profile because the first rely on crude oil as their primary feedstock and the second are accorded high priority status in the event of natural gas curtailments. An obstacle to this profile however, is that, as of August, 1979, FERC does not certify long-term interstate transportation of (non-agricultural) user-owned gas for use as feedstock or boiler fuel (see Chapter V, Section F).

Note that if not stored or used locally, geopressured methane in excess of the petrochemical company's needs would be marketable at decontrolled prices to pipelines anxious to secure supplies of boiler fuel gas for resale.

There is precedent from the mid-1970's for joint ventures between large energy users and oil and gas producers. Such ventures would spread risks and lessen the "front-end" capital drain on each party. For a petrochemical firm without a production subsidiary, the oil and gas producer would bring invaluable exploration, production, and marketing expertise. The developer, whether in a joint venture or otherwise, would be entitled to the tax credits, methane depletion, and IDC deductions outlined in Table 10-1.

Two previously unmentioned factors admittedly operating against this profile's occurrence are (1) the higher than customary (for it) risk to which a petrochemical firm would be exposed and (2) the fact that other unconventional sources of gas, such as coal gasification, might be more attractive because they also produce feedstocks in addition to methane.

D.2. Gas Transmission Company: Boiler Fuel Gas Supply

A gas transmission company, through its production subsidiary, might elect to develop geopressured-geothermal reservoirs to secure a source of boiler fuel methane. The subsidiary would handle all aspects of development, with the possible exception of gas stripping and compression.

This profile is premised on deep reinjection of demethanized brine for the reasons previously discussed, plus the reason that generation of electricity for sale would be alien to the business tradition of a gas utility. Although the transmission company might prefer to conduct the stripping and compression functions itself as a means of transferring operating expenses and capital equipment to its rate base, this is regarded as improbable because utility regulatory bodies, particularly FERC, are becoming increasingly restrictive concerning functions which are "utility" in nature; particularly tight scrutiny may also be expected where a transmission company is purchasing methane at decontrolled prices from its own subsidiary. Indeed, the whole subsidiary-producer/parent-purchaser arrangement of this profile has unfortunate anti-trust enforcement overtones.

The producer subsidiary could pass along to the transmission company in the form of lower gas prices the tax credits and methane-related deductions of Table 10-1; the utility prohibition on alternative energy property tax credits (on wellhead generators, e.g.) would not be a factor, nor would the FERC's rule against "normalized" treatment of avoided tax. Note that there is a conflict of interest between royalty holders on the one hand and transmission company and regulatory authorities on the other regarding gross income realized by the subsidiary from sale of geopressured methane.

The geopressured methane in this arrangement would be marketable as boiler fuel, but would be general pipeline supply gas subject to curtailment and might be incrementally priced to industrial customers. Transmission companies currently have in place an extensive and underutilized pipeline grid overlying the zone of Texas geopressured-geothermal reservoirs. Although geopressured-geothermal development would be a rather risky and expensive venture for a transmission company subsidiary, this will apparently also be the case with development of alternative unconventional gas sources. As a further indication of this profile's likelihood, transmission companies have already demonstrated preliminary interest in the resource by their funding of geopressured-geothermal research at the University of Texas and the Institute of Gas Technology.

D.3. Integrated Energy Company: Business as Usual

An integrated energy company might elect to develop geopressured-geothermal reservoirs for their gas content. This gas would most often be sold to transmission companies, but might on occasion be used in the refinery end of the developer's business as feedstock or boiler fuel. The same rather remote possibility for geothermal process preheat in refineries exists here as in the petrochemical cameo.

Of all the potential participants in resource development, integrated energy companies would have the most access to internally generated financing. They would also be best able to handle the lease acquisition and actual production problems. Too, they may be expected to feel the most pressure to have some role in geopressured-geothermal development because, after all, deep and exotic hydrocarbon production is part of their ethic. On the other hand, their financial strength opens to them many business options, most of which will appear potentially more lucrative than geopressured-geothermal development.

The tax credits and deductions of Table 10-1 would be available to the integrated energy company. As to percentage depletion on the methane, this would be a deduction not available on other forms of gas production. Should Congress pass a "plow-back" deduction from federal tax liability on crude oil "windfall" profits, the tax incentive for an integrated energy company to develop geopressured-geothermal reservoirs would, of course, be enhanced.

D.4. Electric Utility: Boiler Fuel

An electric utility, through its own production subsidiary or that of a gas utility, might produce the resource to obtain methane for use as a boiler fuel.

Generally, under the Powerplant and Industrial Fuel Use Act of 1978, no new base or intermediate-load gas-burning powerplants may be constructed nor may similar existing plants burn methane after 1990; peak-load plants, because of environmental and service reliability concerns, may possibly be exempted from these prohibitions. The Economic Regulatory Administration has removed this prohibition altogether for plants fueled by geopressured methane from wells spudded prior to 1990. This creates a market for geopressured gas to fire current intermediate and base-load plants which are still in existence after 1990. Unless there are technological developments which would enable the different components of the resource to be economically used together to generate electricity, or events dramatically raise the price of other base-load fuels, new base and intermediate-load plants to be fueled by geopressured methane will probably not be built because of the high cost of this fuel.

Texas electric utilities, especially, have much gas-fired intermediate and base-load capacity which will have to be retired by 1990, lacking boiler fuel gas supply; while the high cost of geopressured methane may preclude building new plants to use this fuel, the capital savings from using it in existing facilities may make that alternative attractive. In this profile, the production subsidiary of the utility would handle all production functions. The subsidiary would take all exploration risks and the tax benefits described in Table 10-1. Again, "utility" limitations on tax benefits are not a factor and, therefore, utility fuel purchase prices should reflect tax benefits received by the production subsidiary.

A major advantage of this form of participation in geopressured development for the electric utility is that it is not strictly dependent upon the size of any particular reservoir, as would be the case were the utility generating electricity from the thermal component of the resource. Electricity may be generated from methane at a plant any distance from the geopressured reservoir and more than one reservoir may be used to produce the methane used in a single generating plant. This gas, as long as it did not enter an interstate pipeline, would belong to the utility and therefore would generally not be subject to curtailment. Regulations pursuant to NGA 7(c)(2) might be implemented to remove the interstate transmission restriction.

A variation on this profile would have the utility using the methane in new peak-load plants, where it could not obtain an exemption from the Fuel Use Act to burn regular methane for environmental or other reasons. A potential problem with this is that demand would be intermittent (by definition), while supply would be continuous. This would necessitate storage or sale of the gas to another boiler fuel user. If there existed a significant quantity of this extra gas for sale, a gas pipeline production subsidiary, rather than the production subsidiary of the electric utility, might undertake the exploration and development.

D.5. Utility Electricity Generation: Project Company*

An electric utility might agree to lease from a project company a hybrid geothermal/methane-fired 30 megawatt (net) electricity generation facility. The project company would supply the electric utility with geopressured methane and geothermal brine (heat) with which to fuel the plant and the utility would be obligated for a 20-year period, or as long as power generation in the facility was "commercially feasible", to purchase the brine and methane and pay lease rental, operation, maintenance, and certain tax expenses on the facility. The project company would be responsible for the shallow reinjection of the spent brines.

This arrangement would presumably have come about because the electric utility was approached by a project company which had a geopressured-geothermal property which appeared appropriate for development. The project company in this profile is postulated to be a shell entity established to take advantage of highly leveraged,

*This profile is patterned on the financing scheme presented in the Panawek reference, infra.

nonrecourse, debt-financing under the Geothermal Loan Guaranty Program. The project company would presumably be structured in such a way that default under the Geothermal Loan Guaranty Program, should the geopressured property not prove to be commercially viable, would not have intolerable ancillary financial consequences for the project company principals. Because the project company itself would not be in the trade or business of furnishing electric energy, its property would presumably not be "public utility property" and, therefore, many of the capital investments made in the hybrid facility would qualify for additive alternative energy property tax credits. Some percentage of these credits would be passed along to the electric utility in the form of reduced lease rentals.

This profile has numerous advantages for the utility. Principal of these is that it is required to bear none of the reservoir risk. The project company/producer would presumably be the party exposed to potential liability for damages from surface subsidence or disturbance of subsurface formations. The utility in this profile does not make capital outlays on which earnings are delayed for several years, as would be the case if it financed construction of the facility directly. The utility's rate payers bear all the cost of power generation in this profile because all expenses would be appropriate for reimbursement as utility operating expenses. The fact that this profile does not allow for capital additions to the utility's rate base is probably not significant because those additions would, in any event, be small and arrive during an era of rapid capital expansion.

This arrangement is also attractive for the project company, principally because it can finance 75 percent of the project costs on a non-resource basis under the Geothermal Loan Guaranty Program. The project company, or at least its equity investors, would be required to maintain a 20 percent interest in the project for the life of the project but would not be subject to utility regulation. The project company would, of course, amortize the project over a period of years and be allowed to claim accelerated depreciation which might be unavailable to the utility directly. Further, at the end of the lease period, the facility and geopressured properties would remain with the project company, which might realize some salvage or re-lease value from them. However, because this profile does contemplate use of the Geothermal Loan Guaranty Program to obtain financing for reservoir development and construction of the facility, the ability of the equity investors to claim tax losses in excess of their 20 percent equity investment is apparently foreclosed by the Internal Revenue's "at risk" provisions related to guaranteed or nonrecourse loans.

As discussed earlier, geologic evidence developed to date does not indicate that single or "contiguous" reservoirs sufficiently large to support three or four 40,000 barrel/day wells for 20 or 30 years without deep reinjection are likely to exist along the Gulf Coast; if this evidence holds up into the mid-term, it would not appear that this profile, despite its institutional advantages, is in fact likely to occur.

D.6. Utility Electricity Generation: Utility-Owned Facility

An electric utility might elect to contract for the construction of a hybrid geothermal/methane-fired 30 megawatt electricity generation facility to which it would hold title. In this profile, the utility's production subsidiary would be expected to secure and develop the geopressured property and sell heat and geopressured methane from the property to the parent utility company to fuel the facility, which the parent utility would operate. The subsidiary would be responsible for shallow reinjection of the spent brine. The activities of the production subsidiary would presumably be internally financed, although utility regulatory bodies might also allow an arrangement in which the parent utility advanced money to the subsidiary in exchange for production payments from the developed resource.

Even apart from the perceived improbability of discovering reservoirs sufficient to support the hybrid facility contemplated by this profile, the profile is considered less probable than the one involving a project company because, here, major reservoir and environmental risks are borne (ultimately) by the shareholders of the electric utility. Although the production subsidiary would presumably be entitled to claim the additional 10 percent investment tax credit on the methane stripping equipment, the utility in this profile would be prohibited from claiming alternative energy property tax credits on components of the generating facility itself because these credits are unavailable for public utility property. Of a more positive nature, this profile does eliminate the "middle man" project company of the previous profile and, therefore, may promote lower overall costs for a successful development project. Also, an arrangement in which the utility actually owns its power generating facilities is much more in line with the business traditions of an electric utility.

CHAPTER XI

PROBABLE IMPACTS OF NEW GOVERNMENT INCENTIVES ON MID-TERM RESOURCE UTILIZATION PROFILES

A. INTRODUCTION

This chapter examines the probable impacts of some 25 potential new government incentives on the mid-term utilization profiles developed in Chapter X (see Table 11-1 for an abbreviated restatement of those profiles). The purpose of this examination is to highlight for government decision-makers incentives which might prudently be sponsored between now and some period in the mid-term, and to make explicit the probable correlation between the incentives sponsored and the type of resource utilization structure which evolves. The incentives examined here were selected from a larger set (68, Appendix D) on the bases of their potential favorable impact, their political reasonableness, and, to a lesser extent, their tendencies to affect the profiles discriminantly.

No examination is presented of government actions which might stimulate development of other energy resources and, thereby, potentially place geopressed-geothermal energy at a competitive disadvantage; this restriction is imposed largely to keep our examination within manageable bounds. Because county governments in Texas have very little land-use regulatory authority and because there is very little federal land overlying onshore Texas geopressed reservoirs, the incentives examined in this chapter do not include any targeted to lessen regulatory duplication of the types which affect geothermal development in western states.

The incentives examined in this chapter are grouped according to the risk/expected value dichotomy development in Chapter IV. Thus, incentives such as tax credits and deductions are characterized as affecting primarily a project's expected present value and incentives such as insurance against early reservoir failure or surface subsidence are characterized as affecting primarily the risk that a project's actual present value will deviate substantially from its expected present value. Risk reduction incentives are further grouped according to the types of risk which they address. Of course, a single incentive may well have a favorable impact on a project's expected present value and simultaneously reduce one or more of the risks which make that expected value calculation uncertain. The allocation of an incentive to one group or sub-group is, therefore, not in all instances the only reasonable allocation which might be made.

Incentives within groups and sub-groups are examined in roughly the order of their levels of impact on one or more of the profiles. Incentives which have a significant impact on at least one of the six main profiles are preceded by a "*" symbol; those which, by their probable impacts, most clearly discriminate between profiles are preceded by a "+" symbol. Following the narrative examination of all incentives is a matrix display which summarizes the level of impact each incentive is anticipated to have on each profile.

An assumption has been made regarding the impacts of certain incentives on regulated utilities. This assumption is that regulatory bodies will allow financial benefits conferred by incentives on utilities to remain with the utilities. This assumption is at odds with traditional utility regulatory philosophy. Normally a utility is allowed to earn revenue sufficient only to cover its actual operating expenses, capital investments, and a reasonable rate of return on those capital investments; consequently, benefits such as tax credits and some tax deductions are traditionally excluded from operating expenses and therefore usually do not accrue to a utility's shareholders. Rather, they are "flowed through" in the form of reduced rates to a utility's customers. Because flowed through economic benefits have little, if any, stimulative impact on a utility, we have assumed that economic benefits arising from postulated incentives are not flowed through.

Finally, our treatment of federally funded R and D efforts as a new incentive is open to criticism because, of course, these efforts have been on-going for some time and are therefore not "new". Federally funded R and D efforts are examined here, however, because their areas of focus and levels of support are subject to change prior to and during the mid-term; moreover, our study indicates that, overall, R and D incentives are currently the best means by which to expedite geopressed-geothermal development.

TABLE 11-1
SIX PROFILES FOR UTILIZATION OF THE
GEOPRESSURED-GEOTHERMAL RESOURCE IN THE MID-TERM

• Petrochemical firm profile:	development by a petrochemical firm through its production subsidiary of reservoirs for their methane content alone; this methane would be used as feedstock and as boiler fuel
• Pipeline company profile:	development by a gas transmission company, through its production subsidiary, of reservoirs for their methane content alone; this high-cost, incrementally priced methane would be sold to an industrial boiler fuel market
• Integrated profile:	development by an integrated energy company of reservoirs for their methane content alone; though the company might use the methane in refinery processes, most would be sold to transmission companies
• Electric utility methane profile:	development by an electric utility, through its production subsidiary of reservoirs for their methane content alone; this methane would be used as fuel for (largely) existing gas-fired boilers.
• Project company profile:	development by a project company of reservoirs for both their methane and heat content; these components would be sold to an electric utility for use in a hybrid methane/heat fueled powerplant owned by the project company
• Utility plant ownership profile:	development by an electric utility, through its production subsidiary, of reservoirs for their methane and heat content; these components would be used in a hybrid methane/heat fueled powerplant owned by the utility.

B. RISK REDUCTION INCENTIVES

B.1. Reservoir Risk

*B.1.(a) Federal Support of Reservoir Research and Development Projects. DOE could continue and intensify its support of R and D projects which improve understanding of such reservoir parameters as size, distribution, interconnection, and methane and salt content. DOE is currently funding university research of this nature and is contracting with oil and gas producers for a number of "design wells" and "wells of opportunity" (see Chapter III and Chapter IX, Section C).

Improved understanding of the behavior, content, and occurrence of geopressured-geothermal reservoirs would favorably impact all the profiles, if that improved understanding indicated that development of the resource were more economically viable than now appears to be the case. In that positive case, this initiative could be expected to have a moderate favorable impact on the four gas production profiles. Similarly, it could be expected to have a significant to very significant favorable impact on the two utility electricity profiles because those contemplate surface facilities which are reservoir-dependent. The impact would not be as favorable on the project company profile as on the other utility electricity profile because the project company would probably owe its existence, in part, to the need of an electric utility to have a buffer entity to shoulder the consequences of reservoir uncertainty.

Our discussions with industry representatives clearly indicate that reduction of reservoir uncertainty is the single most important contribution DOE can make to further resource development. (See, particularly, Appendix B).

*B.1.(b) Insurance Against Early Reservoir Failure. The federal or state government might underwrite policies to insure against certain financial losses which come about because of the early failure of geopressured-geothermal reservoirs. For this analysis, the assumption is that insurance coverage would be limited to the unamortized value,

less salvage, of surface facilities which utilize the heat component of the resource. No such government program currently exists and the prospects for a similar component private program are not good because private insurers may be expected to characterize the risk involved as a specific business risk; generally, specific business risks, as opposed to more general risks such as loss from flood, fire, or theft, are not considered by private insurers to be prudent risks against which to insure.

This incentive would have no impact on the four gas production profiles as they are written, because the only surface facilities contemplated there which use the heat component of the resource are the relatively inexpensive and presumably entirely salvageable wellhead generators. Variants of two of these profiles, in which the petrochemical firm or integrated energy company makes some process application of the heat component of the resource, would experience a moderate favorable impact from this incentive because surface facilities in those variants would presumably entail rather large capital outlays, would be site dependent, and would probably not have much salvage value in the event that geothermal fuel supply disappeared.

The utility plant ownership profile would experience a very significant favorable impact from this incentive because the hybrid geothermal/methane power facility contemplated in that profile would require a large capital investment which would be amortized over an extended period of years. To some extent, the project company profile would be undermined by this incentive because the risk of reservoir failure, one of the principal rationales for existence of the project company, would be insured against if this incentive were in place; on the other hand, the project company or, perhaps, the general partner within the project company would certainly welcome insurance protection against reservoir failure. On balance, it appears this incentive would have a moderate favorable impact on the project company profile.

As reflected by the responses of members of the potential Texas geopressured-geothermal process heat market and the comments of industry representatives at our round table discussions, insurance against early reservoir failure is perceived to be a desirable incentive (see Chapter VIII and Appendix B).

B.1(c) Compulsory Unitization. The state legislature might provide the Texas Railroad Commission with authority to compel unitization of geopressured-geothermal reservoirs. Currently, no state or federal authority is empowered to regulate or prohibit simultaneous exploration of a Texas geopressured-geothermal deposit (larger than a natural gas production unit) by developers who do not voluntarily coordinate their efforts. It is anticipated that the manner in which a geopressured reservoir is produced will be more critical to its commercial success than is the case for most oil and gas production efforts.

This incentive would have only a slight impact on the four gas production profiles because the expenses of drilling the deep production and reinjection wells would presumably dissuade a second party from attempting to tap a reservoir already being exploited by someone else. Moreover, these profiles as written do not contemplate expensive nonsalvageable surface equipment. This incentive could be expected to have a moderate impact on variants of the petrochemical firm and integrated energy company profiles in which surface facilities, other than wellhead generators, are postulated for utilization of the heat component of the resource. Although the likelihood of a second party also attempting to exploit a geopressured-geothermal reservoir under these variants is no greater, the economic loss to which the large energy user or integrated energy company would be exposed is. This incentive should have the most impact, a moderate to significant favorable impact, on the utility electricity profiles because those contemplate expensive, nonsalvageable, surface facilities which would only pay for themselves over long time periods. Also, those profiles might encompass an arrangement in which several "contiguous" reservoirs would be produced to provide geothermal fuel for the power plants; the number of opportunities for competing exploitation of the same reservoir would be, therefore, increased.

Implementation of this incentive in Texas might, however, be opposed by oil and gas producers fearful of its effect as a precedent for unitization of conventional oil and gas reservoirs; opposition to unitization of conventional reservoirs is very strong in some circles.

***B.2. Catastrophic Risk. Insurance Against Subsidence or Aquifer Damage.**

The state or federal government might underwrite policies which insure against liability for surface subsidence or damage to subsurface formations because of

geopressured-geothermal production or brine reinjection. Alternatively, the government might put a statutory ceiling on the total damages to which a developer would be liable because of surface subsidence or damage to subsurface formations; in this event, the government might assume responsibility for damages in excess of a ceiling amount.

Currently, neither form of absolute protection is available to the geopressured developer, either through government or private insurers. The contractor on the Brazoria County geopressured test well was, with some difficulty, able to secure \$100 million of subsidence coverage through private insurers; the likelihood of subsidence because of activities at a test well is, of course, less than in the situation of full development. There is precedent for absolute protection, however, in the Price-Anderson Act, which places a ceiling on total damage claims from nuclear power industry accidents. The impetus for government involvement here is similar to that for involvement in the nuclear industry; though the probability of loss of life, damage to subsurface (principally, oil and gas) formations, or other large economic loss because of subsidence is very low, the size of that loss, should it occur, could be quite high. Moreover, the loss could occur long after production begins.

The impact of this incentive on the four gas production profiles is projected to be slight because those profiles postulate deep reinjection, which should obviate the geologic causes of subsidence and circumscribe the areal extent over which subsidence is even a possibility. This incentive is calculated to have some impact on those profiles, however, in that the fear of economic consequences of subsidence or damage to other subsurface oil and gas reservoirs might itself have a negative influence on geopressured-geothermal development. The incentive would have a moderate favorable impact on the profile variants in which the petrochemical firm or the integrated energy company opts for shallow reinjection and net generation of electricity. The incentive would have a greater impact here because of the increased risk of subsidence and subsurface aquifer damage which accompanies shallow reinjection. The utility electricity profile which does not involve a project company could expect to experience a significant favorable impact from this incentive because it postulates a development in which large volumes of water are withdrawn from each of several wells. This means that a greater area both above and below the surface is potentially affected by the removal of geopressured brine and a greater subsurface area might be affected by its shallow reinjection. The project company profile would experience a moderate favorable impact from this incentive for the same reasons as the other utility electricity profile, offset by the fact that the limitation of developer risk also undermines one of the reasons for existence of a project company.

Again, our round table discussions with industry representatives show that they perceive protection from the economic consequences of subsidence and damage to subsurface formations to be a desirable incentive.

B.3. Market Risk

***B.3.(a) Federal Support of Geothermal Electricity Generation and Process Heat Research and Development Projects.** DOE could continue and intensify its support of R and D projects which examine methods to generate electric power from (particularly) hybrid geothermal/methane fueled power plants and which examine methods to utilize low-grade process heat. Currently, DOE is funding geothermal power plant and direct utilization research, both along the Gulf Coast and in western states; with regard to hybrid facilities, however, most of the work remains to be done. Research along either of these lines, of course, provides benefits for those who would develop and market more conventional geothermal deposits, solar energy, or co-generation facilities.

This incentive could be expected to have at least a slight favorable impact on all of the profiles. Even the gas production profiles, which as written do not contemplate net electricity generation, do contemplate the use of wellhead generators driven in some fashion by the thermal and kinetic components of the resource. Certainly, the profile variants in which the petrochemical firm or the integrated energy company opt to produce electricity and reinject the brine shallow, or make process application of the heat component of the resource, would experience a moderate favorable impact from this incentive. The impact that this incentive would have on the two utility electricity profiles could be very significant, depending on the results of the R and D effort, because these two profiles contemplate use of both the thermal and methane components of the resource for electricity generation. Moreover, this incentive would address problems of metallurgy and the operation of low pressure turbines, either of which could slow evolution of the last two profiles.

+*B.3.(b) Geopressured Methane Exclusion From Curtailment. The FERC might rule that geopressured methane owned by the pipeline companies is not general pipeline supply gas subject to curtailment during times of shortage. Currently, each interstate pipeline company has a curtailment plan approved by the FERC which, in general, calls for curtailment of gas deliveries first to interruptible customers, then to nonagricultural industrial process and feedstock customers (see Chapter V, Section F). There is precedent for special regulatory encouragement of geopressured methane development in that the Economic Regulatory Administration has ruled that boilers fired by geopressured methane are exempt from the prohibitions of the Fuel Use Act (Coal Conversion Act). In light of the low curtailment priority now accorded boiler fuel customers, this proposed incentive would complement the ERA ruling nicely.

Of course, this is an incentive which depends for its effectiveness on a continued natural gas shortage. Even assuming a continued gas shortage, this incentive would likely have only a slight positive impact on the petrochemical firm profile and the electric utility methane profile. The impact is seen to be slight because neither of those profiles contemplate that the producer of the geopressured methane would ever lose title (as, by sale to an interstate pipeline company) to the gas produced. This gas would, therefore, not be subject to curtailment. However, there is some possibility that geopressured methane in excess of the petrochemical firm's or electric utility's needs could be produced, in which case this incentive would increase the market value of the excess gas and therefore aid marketing of that gas. This incentive might also provide a mechanism by which to circumvent the problem of the common carriage of the geopressured methane from the reservoir site to the site where it will be used (see Section B.5.(b)); if the gas were not subject to curtailment, then the producer and end-user might have no objection to selling the gas to an interstate pipeline company and repurchasing it elsewhere at a modest price increase which would cover the gas transmission costs. The incentive should have a moderate positive impact on the integrated energy company profile because the company there would presumably find it easier under this incentive to market geopressured methane to interstate pipeline companies; the marketing of geopressured methane to some second party is, of course, the principal motive postulated for this party's participation in geopressured-geothermal development. The incentive should have a significant favorable impact on the interstate pipeline company profile because it would help those companies secure a reliable source of gas for industrial and electric customers who might otherwise switch to alternative fuels because of a fear of curtailment. Those customers are particularly important to pipeline companies because they use gas in large quantities on schedules which can be relatively easily anticipated. The two utility electricity profiles would presumably be unaffected by this incentive because the hybrid facilities postulated there will be located at the reservoir sites.

+*B.3.(c) Geopressured Methane Exclusion from Incremental Pricing. Congress might amend the Natural Gas Policy Act to exclude geopressured methane from the incremental pricing provisions of that act. Currently, the Natural Gas Policy Act provides that so much of the first sale acquisition cost of various gases, including geopressured methane, which is an excess of the "incremental pricing threshold" must be passed along by interstate pipeline companies to specified industrial (nonutility) end-users of natural gas. This pricing method is distinguished from traditional "rolled-in" (averaged) pricing of natural gas from various sources at various costs.

This incentive is projected to have the most impact, a significant one, on the pipeline company profile. This is so because the incentive affects most directly the interstate pipeline customer market (industrial boiler fuel) on which incremental pricing provisions now fall most heavily and which is best able to convert to alternate forms of energy. The loss of an industrial customer has a significant negative effect on an interstate pipeline company because it is the industrial customer whose level of gas use is most easily anticipated and is, often, quite large. Further, the rolling-in of acquisition costs of geopressured methane could help the interstate pipeline company to improve its overall gas supply capability while simultaneously maintaining a competitive (averaged) market price for its product. Finally, this incentive would decrease the heavy record-keeping/accounting burden which incremental pricing regulation currently imposes on interstate pipeline companies.

This incentive would probably have no impact on the petrochemical firm profile because that utilization scheme does not envision the sale of natural gas to an interstate pipeline company. This incentive should have a moderate, favorable impact on the integrated energy company profile as it would make it easier for the integrated energy company to market geopressured methane to the interstate pipeline companies.

The incentive is seen as having no impact on the remaining profiles, in that those do not contemplate sale of geopressured methane to an interstate pipeline company; were there to be excess gas produced under those schemes, then this incentive would presumably make the marketing of that excess gas easier.

Implementation of this incentive should not be undertaken until after a thorough study has been made of the actual economic aspects of incremental pricing. There are indications that the incremental pricing threshold for geopressured methane is so high (130% of the Btu equivalent price for #2 fuel oil landed in New York) that the differential between it and the incremental pricing ceiling will be negligible (see Chapter IX, Section E).

*B.4. Financial Risk. Loan Forgiveness.

The Geothermal Loan Guaranty Program might be amended to provide that loans guaranteed under that program be forgiven (repaid by the federal government) instead of declared in default in the event of early reservoir failure; this incentive might be structured so that the percentage of the loan to be forgiven decreased with the passage of time. The incentive might also be structured so that only loans which finance surface electricity generation facilities could be forgiven while others, such as those for reservoir exploration and development, would continue to be backed by the federal guaranty in the event of default by the obligor. Another approach is taken by the Omnibus Geothermal Energy Commercialization Bill (Senate Bill 1388), introduced this, (the 96th) congressional session, which would establish a separate, direct, forgivable federal loan program to finance half the costs of geothermal reservoir exploration and confirmation (see Chapter IX, Section B); if a program such as this were available for geopressured methane projects and if the means of "confirming" geopressured-geothermal reservoirs were sufficiently reliable by the mid-term, then such a loan program would likely meet developers' needs without exposing the federal government to potential financial liability for expensive electricity generation facilities.

The effects of any form of this incentive are seen as uniform across the four gas utilization profiles. If the forgiveness feature were available only for loans taken out for the construction of surface electricity generation facilities, then the incentive would have no effects on the profiles as written, because they do not contemplate that there will be surface facilities for electricity generation. If the forgiveness feature attached to loans taken out for reservoir exploration and confirmation, then the incentive could be expected to have a moderate favorable impact on each of those profiles. The petrochemical firm and the integrated energy company would each, presumably, be somewhat less comfortable with the federal "bail-out" aspect of this incentive than would the interstate pipeline company or the electric utility; the pipeline company and the electric utility, however, each has a more rigid and well-scrutinized debt structure in place than does a petrochemical firm or an integrated energy company and, therefore, might be more likely to encounter adverse creditor reactions on the occurrence of a "default" which is termed and administered as a "forgiveness."

Any form of the incentive is thought to have only slight favorable impact on the development scheme envisioned in the project company profile. This is so principally because any incentive which serves to transfer risk of reservoir failure to the federal government undermines one of the main reasons for the existence of a project company. The form of the incentive which limits its coverage to loans taken out for development of surface electricity generation facilities would be expected to have slightly more favorable impact on the project company because it could still bear the non-transferable risks of reservoir exploration and development. This incentive would be expected to have the most favorable impact on the utility electricity profile in which there is no project company. If the forgiveness feature applied to surface facilities only, the incentive would have a significant impact because the financial risk of constructing expensive reservoir-dependent surface facilities would be transferred to the federal government, presumably at a lower cost to the electric utility than in the profile in which the project company assumes that risk. If the forgiveness feature applied only to loans for exploration and confirmation projects, the incentive would still have a moderate impact because, though the amount of money at risk in an exploration and confirmation project would be less than that at risk if power generation facilities were being built, the level of risk itself would presumably be higher (i.e., the exploration and confirmation project would presumably supply reservoir data which would lower the risks of building a reservoir-dependent surface facility).

B.5. Regulatory Risk

*B.5.(a) Common Carriage of User-Owned Geopressured Methane. The FERC by regulation pursuant to Section 7 of the Natural Gas Act could provide for the long-term interstate common carriage of user-owned and developed geopressured methane reserves for use as (a) feedstock or (b) boiler fuel. Currently, interstate pipelines are not common carriers; most of the gas which they carry they also own. There are, however, instances in which pipeline companies act as common carriers (see Chapter V, Section F). For example, FERC Order 2 allows the two-year certification of interstate pipeline companies for the common carriage of user-owned natural gas to be used to offset anticipated curtailments in natural gas feedstock supply. Similarly, 1978 Amendments to the Natural Gas Act have been implemented in part by the FERC to allow five-year certification of interstate pipeline companies for the common carriage of natural gas owned by certain "high priority" users. Currently, these users are predominately members of the food, fiber, and fertilizer industries who have alternate fuel capability but who prefer to continue using natural gas.

An incentive such as this could also be offered to facilitate geopressured methane transportation in the intrastate market, though the obstacles to such transportation are not generally severe in the intrastate market; if necessary, the Texas Railroad Commission can now order common carrier intrastate lines to carry anyone's gas for a fee and can order other lines to carry utility-owned gas.

The degree to which this government incentive would operate to encourage the development of geopressured methane is dependent upon a continued shortage of natural gas from other sources. If the natural gas shortage continues, then the current proscriptions against the use of most types of methane for boiler fuel may be expected to continue, as may the fear of low priority industrial users that their gas supply will be curtailed. If the gas shortage continues, then, this incentive could have a significant impact on the utilization structures outlined in the petrochemical firm profile and the electric utility methane profile. It would not appear to have any favorable impact on the gas pipeline profile and, indeed, might have a slight adverse effect on the interstate gas transmission companies of that profile because it would allow the end-user to compete directly with the transmission company for the purchase or development of gas reserves. It is seen as having a moderate favorable impact on the integrated energy company profile because it would provide another market to which the company might sell this high-cost boiler fuel gas; were the integrated energy company to want to use the geopressured methane itself at a remote location, this initiative would also further those efforts. This incentive is not seen as having any impact on either utility electricity profile because the utilization schemes postulated there occur at the reservoir site.

B.5.(b) Exemption from Utility Regulation. The Federal Power Act might be amended to provide an exemption from utility regulation for firms which generate small amounts of electric power from geopressured-geothermal resources and sell a portion of that power. Currently, the FERC is empowered to exempt certain small power producers and qualifying cogenerators from regulation under the Public Utility Holding Company Act and other state and federal laws respecting electric utility rates. One who produced electric power from geopressured-geothermal resources would not normally qualify as a small power producer or a cogenerator. A similar change in state law would be required to benefit those who generate electricity from geopressured-geothermal resources, but do not sell the power in interstate commerce or to electricity grids regulated by the FERC; again, however, the lower level of regulatory control in the intrastate market means that regulatory obstacles there are also less severe.

This incentive is anticipated to have no impact on any of the principal profiles. This is so because the profiles either contemplate no net electricity generation or feature electric utilities, which are of course accustomed to regulation. The variants in which the petrochemical firm or integrated energy company elects to reinject the geopressured brine shallow and realize net electricity generation from a wellhead power generator would experience significant favorable impacts from this incentive; these variants involve the activities of non-utilities who would be loathe to become entangled in utility regulation.

B.5.(c) Current Rate Base Treatment of Geopressured-Geothermal Construction Work in Progress. Electricity utility regulatory bodies might allow the cost of construction work in progress on geopressured-geothermal electric power generating facilities to be included in the base on which a utility's rate of return is calculated. The general regulatory philosophy on this subject now is that the rate base should not reflect the cost of new plant additions until those additions actually come on line; thus, today's rate payers do not finance plant additions which will benefit tomorrow's rate payers.

This incentive is seen as having no impact on the petrochemical firm, pipeline company, or integrated energy company profiles because those do not involve an electric utility. The incentive is seen as having only a slight impact on the electric utility methane profile as written, because the production subsidiary in that profile bears all the drilling expense and because the gas plant construction expense borne by the electric utility would not be large, relative to the expense of other types of power generation facilities. Further, the expense of any new gas-fired facilities may be expected to enter the rate base quickly because neither the construction nor the licensing of these facilities requires much time. The incentive would have no favorable impact on the project company profile and might, in fact, operate as a disincentive to evolution of that structure because the incentive would undermine one of the reasons for existence of a project company; absent this incentive, the costs of delayed payback on plant investment are transferred from the utility to the project company in that profile. The incentive should have a moderate favorable impact on the other utility electricity profile in that, though exploration and most other development costs would be borne by the production subsidiary, the utility would have to bear the cost of the power generation facility itself and this facility, because it would rely on new technologies and would handle large volumes of saline brine, would be rather more expensive than conventional gas-fired electricity generation facilities. There might also be more delay in the construction and licensing of a facility which would be fueled in part by large volumes of hot brine or utilize explosive working fluids.

B.5.(d) Methodology for Allocating Costs Among Resource Components. State and federal regulatory authorities might adopt a common method by which to allocate geopressured-geothermal development costs and values between the resource's geopressured methane component, on the one hand, and geothermal component, on the other hand.

The benefit which would be anticipated from this incentive is that uncertainty in the calculation of royalty rights, severance and *ad valorem* taxes, income taxes and reasonable public utility rates would be reduced in instances where some use and, therefore, obvious economic value, is postulated for the geothermal component of the resource. Because such pieces of equipment as wellhead generators might be driven by the thermal and kinetic components of the resource, this incentive might have a very slight positive impact on the four gas production profiles, even though they do not contemplate sale of the geothermal product of the resource. This incentive could be expected to have greater impact on the utility electricity profiles, where the sales of large quantities of heat are contemplated. Note, however, that uncertainty itself might on some occasions be desirable as it initially would allow the parties to the development project to allocate as they choose costs and revenues associated with the geothermal component.

C. EXPECTED VALUE INCENTIVES

C.1. Production Credits

***C.1.(a) Methane Production Credit.** The federal government might pay a credit for each Mcf of geopressured natural gas a producer sold or utilized. The credit might be fixed, "X" ¢/Mcf, or might be variable to offset the differential between a government-determined price and the (lower) market price at which the gas actually was sold or could have been sold. This incentive would probably best be administered as a refundable tax credit, though some formal interaction between the Internal Revenue Service and the FERC would be required to validate taxpayer credit claims; note that Section 107(d) of the 1978 Natural Gas Policy Act requires that a producer who took advantage of this proposed incentive, if the incentive were in fact administered as a tax credit, would not be allowed to "enjoy" decontrolled pricing of his gas (see Chapter IX, Section E).

Our analysis and discussions with industry representatives indicate that a production credit would be the most effective expected value incentive the government could offer, if the credit were large enough. Unfortunately, there are currently so many uncertainties about future energy prices and about the costs of developing the geopressured-geothermal resource that calculation of a fixed credit amount which is large enough to be stimulative, but which is not "too" large, will be very difficult. This militates in favor of the differential credit as an incentive. The differential credit, however, entails more regulation overhead for both the producer and the government and would establish a system under which price cutting by the producer would not worsen his financial position at all but, rather, would hurt the federal

treasury and other energy producers. Also, a differential credit would have more negative anti-trust ramifications than would a fixed credit, particularly where sales occur between parent and subsidiary companies. Our consideration of the various advantages and disadvantages of the two credit types suggests that the fixed credit would be more likely than the differential credit to stimulate geopressured-geothermal development.

There is presently no production credit available to a producer of geopressured methane. The Senate version of the Energy Tax Act of 1978 contained a fixed 50¢/Mcf non-refundable production tax credit for geopressured natural gas; this provision was deleted by the conference committee which reconciled House and Senate versions of the bill.

A fixed production credit incentive would have a significant to very significant favorable impact on all six profiles. The profile involving the pipeline company would probably be most favorably affected because, in addition to the straight rate-of-return benefit enjoyed by other parties in other profiles, the pipeline company, in light of the credit, might be able to purchase the geopressured methane from its production subsidiary at a price beneath the incremental pricing threshold and thereby avoid having to incrementally price the gas to its industrial boiler fuel customers.

After the pipeline company, the integrated energy company is probably in the best position to realize benefits from the postulated incentive because the normal interests of an integrated energy company are such that it could do a volume business in geopressured reservoir development. The production subsidiary in the electric utility methane profile might also direct its activities to realize the benefits of this credit in a repeat basis, though the ERA's boiler fuel exemption would still be the principal impetus for those activities. Under the scheme outlined in the project company profile, the assumption is that some portion of the credit received by the project company would be applied to discount the price of gas sold to the electric utility. Therefore, it is anticipated that the benefit of the credit would be spread over two corporate families instead of being retained within one, as in the other profiles. This may marginally lessen the impact of this incentive in the project company profile.

The differential production credit would likely impact each of the profiles less favorably than the fixed credit, but not in a uniform pattern. The increased level of government oversight postulated to accompany this incentive would be most bothersome to the petrochemical firms and integrated energy companies; the utilities could be expected to tolerate this more easily. The project company profile would apparently benefit from this incentive relatively more than the others because that profile could most easily be structured to minimize the potential anti-trust problem and shift regulatory burdens between parties in a fashion acceptable to them.

*C.1.(b) Geothermal Heat Credit. The federal government might pay a credit for each Btu of geothermal heat which a producer sold or utilized himself. As with the methane credit, this incentive might be a fixed credit or a differential credit. Also as is the case with the methane credit, the effectiveness of this incentive depends primarily on its size. Current law does not provide for any sort of geothermal heat production credit, though there are credits available to those who purchase equipment to utilize geothermal heat (see Chapter IX, Section D(1)).

Our analysis is that the fixed credit is superior to the differential credit because it is administratively less complex and less susceptible of abuse; in the instance where heat is not sold but, rather, is used by the producer, regulation may produce an additional record-keeping/reporting burden undermining either form of the credit.

A fixed credit could have a slight favorable impact in even the four gas production profiles, in which no net electricity generation is contemplated, because the wellhead generators might consume geothermal fuel. The profile variants in which the petrochemical firm and the integrated energy company make some process use of the resource's heat component would experience significant favorable impacts. Because the utility electricity profiles contemplate use of large amounts of heat, these would also experience a significant favorable impact.

*C.2. Federal Support of In Situ Methane Extraction Research and Development

DOE could initiate a program to develop technologies for extraction of geopressured natural gas by means which do not require bringing to the surface large volumes of brine. DOE is currently sponsoring broad-based geopressured-geothermal research, but does not have a program which focuses directly on in situ geopressured methane extraction.

This incentive, if it led to technical advances, could be expected to have a moderate to significant favorable impact on the petrochemical company and electric utility methane profiles because each of these is premised on a desire to obtain geopressured methane. Because of the traditional role played by gas production and supply in the business of an integrated energy company or pipeline company, the profiles involving those parties would experience even more favorable impacts from technological advances related to in situ methane extraction. In situ extraction would allow parties to realize their primary interests in developing the resource without the additional expenses of reinjection wells, surface pumping facilities, and frequent workover of the production wells. This incentive would have either no impact or negative impact on the two utility electricity profiles because those are premised on production of large quantities of geopressured brine; were it not necessary to produce the brine at the surface to extract the methane from it, the likelihood of development schemes such as postulated in those profiles would be lessened.

*C.3. 5-Year Depreciation

The federal government could provide that capital assets purchased for geopressured-geothermal development be depreciable (for federal income tax purposes) over a 5-year period. This incentive would be available to any developer, including a utility. An incentive of this nature would increase the expected value of any project by moving positive after tax cash flows from more remote years to years nearer the initiation of the project; present value calculations discount most heavily those cash flows which are most remote in time. There are currently several authorized methods (which are unavailable to some utilities) for depreciating property "rapidly," but these are, in general, tied to the useful life of a property and therefore prevent complete recovery of costs prior to the end of that property's useful life.

Our analysis indicates that this incentive would have a moderate favorable impact on each profile except the project company profile, on which it would have a moderate to significant favorable impact. The incentive would not address project risk and, therefore, would not be a relatively greater stimulus to arguably more risky development schemes, such as are outlined in the utility electricity profiles. Similarly, it would not offer greater earnings, as a percentage of initial investment, to large projects than to small projects. Of course, the absolute size of tax savings which this incentive would produce during the early years of a project would be increased with the cost of the project. It is because of this last consideration that the incentive's impact on the project company could well be an under-capitalized entity to which the absolute size of cash flows would have practical ramifications not strictly dependent on the size of those flows relative to initial investment (e.g., the incentive might help the company attract new investors, refinance debt, or meet unexpected expenses related to facility modification). Also, the project company profile arises in part to take advantage of tax and loan incentives and, therefore, could be structured to optimize the benefits of this proposed incentive. C.4.

C.4. Rate Base Financing of Geopressured-Geothermal Expenses

*C.4.(a) System Development Expenditures. Regulatory bodies for electric and gas utilities might allow rate base treatment for geopressured-geothermal system development expenditures. The traditional policy at the FERC and other utility rate-setting bodies has been that utility investment in unproven technologies is not sufficiently "prudent" to be financed by rate payers; the risks of proving new technologies have largely been borne by equipment suppliers. Also, gas utility rate setting bodies, particularly the FERC, are becoming increasingly restrictive as to costs which are of a transportation or distribution nature on the other hand; for example, the stripping, drying, and compressing of geopressured methane to pipeline specifications might well be considered production in nature and therefore not appropriate for rate base financing.

A more lenient regulatory policy regarding the prudence of geopressured-geothermal expenditures would, of course, have no direct effect on the petrochemical firm or integrated energy company profiles because those do not involve regulated utilities.

The pipeline and electric utility methane profiles would experience at most a slight positive impact from such an incentive in that all "orthodox" expenses, such as risky production costs, are borne by the unregulated subsidiaries in those profiles; the potential positive impact arises from the possibility that development economics would be enhanced if methane stripping, drying, and compressing costs were treated as utility operating expenses, borne by the utility, and passed through in the rates charged customers. The incentive might actually lessen the likelihood that the project company profile would emerge because the utility's need to have a project company to shelter electric utility shareholders from the risks of reservoir failure or power plant construction problems would be much lessened where the economic impacts of those problems would be borne by the utility rate payers. The incentive should have a significant impact on the other utility electricity profile because that profile involves a relatively large and unconventional surface facility whose usefulness would be tied to the long-term productivity of geopressured reservoirs: equity investors might avoid a corporation which incurred risky expenses such as this to realize only a fixed "utility" rate of return.

+*C.4.(b) R and D Expenditures Flow Through. Regulatory bodies might allow electric and gas utilities to include in "flow through" adjustment clauses the costs of research and development related to geopressured-geothermal energy.

Flow through financing of this nature finds some precedent in fuel purchase adjustment clauses, which many regulatory bodies now allow as a means of reimbursing utilities for fuel purchase costs in excess of projected amounts. Flow through clauses transfer to the utilities' ratepayers costs falling into pre-determined categories without the delay and expense (or safeguards) of rate hearings.

Where the R and D costs were incurred by the utility directly, as, for example, when research on two-phase fluid flow was funded, the pass through of the cost would be very straightforward. In the more complicated case where the costs were incurred by the subsidiary of a regulated utility, the following discussion assumes that they could be added to the fuel purchase price paid the subsidiary by the parent utility and could be recovered in full by the parent company from ratepayers. This would be a departure from the current practices of most regulatory bodies, which do not recognize R and D expenses as an explicit element in the cost of producing and preparing fuel for sale. This discussion assumes that exploratory drilling to discover geopressured-geothermal deposits would not be treated by regulatory bodies as R and D, though extraordinary methods of completion, fracturing, testing, and so forth would be. The incentive proposed here does not extend to blanket regulatory authorization of reimbursement by ratepayers of geopressured-geothermal R and D expenses incurred by utility fuel suppliers other than subsidiaries (i.e., most oil and gas producers), nor to reimbursement of subsidiary R and D expenses via the purchase price of fuels from other than geopressured-geothermal deposits (i.e., conventional natural gas, coal, etc.); obviously, either of these would offer more stimulus to geopressured-geothermal development but might be expected to encounter political and administrative obstacles.

What an incentive of this nature mostly does, of course, is encourage research. Only if that research yields positive results could it be said that the incentive encouraged evolution of any of the profiles. Bearing in mind that caveat, it appears that the incentive could be quite effective. The petrochemical firm and integrated energy company profiles would not, however, be directly affected because neither of those involves a regulated utility. Though a regulated utility might well purchase geopressured methane from the integrated energy company, the incentive assumes that the producer's R and D costs could not, solely because of the incentive, be included in the "reasonable" fuel purchase price paid by the utility. The incentive could have a significant favorable impact on the pipeline company profile, though, and almost that favorable an impact on the electric utility gas production profile. In both of these there are numerous uncertainties related to resource production, separation, and reinjection which will have to be reduced if risk-averse utilities are to play dominant roles in resource development.* The incentive should have only

*This incentive is obviously one which could fairly be assigned to either the "risk-reduction" or "expected value" incentive category.

a slight to moderate favorable impact on the project company profile because the lessening of uncertainty undermines some of the rationale for existence of a project company; of course, a project company could profit from the R and D results of others, especially its electric utility customer, and could probably structure its relationship with the utility in such a way that modifications to the hybrid facility could be designed and tested with the aid by this incentive. The profile most enhanced by this incentive is the utility plant ownership profile. This profile involves only a utility and its subsidiary, and to be economically viable depends on the lessening of uncertainties related not only to the resource but also to the design and operation of the power generating facility itself.

*C.5. Crude Oil Excise Tax Exemption

If the currently contemplated "windfall" profit tax on crude oil sales is adopted, congress may also exempt from taxation so much of that windfall profit as is reinvested in development of various alternative forms of energy, such as geopressured-geothermal energy.

The extent to which this incentive would operate to stimulate geopressured-geothermal development depends, of course, on the percentage of the tax which is avoided by reinvestment in geopressured-geothermal development, relative to the amount avoided by investment in other alternative energy projects. In any event, it would be anticipated to have no impact on the petrochemical firm profile because the subsidiary in that profile would be unlikely to have old crude oil properties from which to sell crude which would be subject to the tax. Similarly, the electric utility gas production subsidiaries in the two profiles in which they appear would not be expected to have old crude oil properties and the impact in this incentive on their profiles is, therefore, thought to be zero. The incentive could have a moderate impact on the project company profile because the producer postulated as the moving force behind the project company could well have crude oil properties which were subject to the tax. A production subsidiary for an interstate pipeline company is more likely than a production subsidiary for an electric utility to have old crude oil properties; if the pipeline subsidiary did have properties of that type, then this incentive could have a significant favorable impact, especially as it would converge with the desire of the parent company to secure a reliable supply of boiler fuel gas for its customers. The incentive would, of course, be anticipated to have a very significant favorable impact on the integrated energy company profile.

*C.6. Interest Subsidy

The government might pay all or some portion of the interest on loans which were taken out for the development of geopressured-geothermal resources. Currently, the government, under the Geothermal Loan Guaranty Program, will guarantee geothermal loans which may lower the interest rates charged by the lender, and may temporarily take up interest payment obligations of a borrower facing default. Otherwise, there are no federal loan incentives which focus on geothermal or geopressured-geothermal energy (see, however, Chapter IX, Section B, for a discussion of a pending loan incentive).

Such an incentive is seen as having only a slight impact on the resource utilization structures of the petrochemical firm and integrated energy company profiles because the principal parties in each of those profiles are thought to be adverse to such obvious government subsidy of their businesses. These parties are also likely to have internal funds available to finance geopressured-geothermal development on a scale which does not include large surface facilities. Although the pipeline and electric utility methane profiles also do not contemplate large surface facilities, the interest subsidy would be anticipated to have more impact there because the gas or electric utility parent company in each of these profiles will be more accustomed to government support and debt-financed projects. This incentive is anticipated to have a moderate to significant impact on the project company profile because that profile does call for the construction of significant surface facilities and a highly leveraged project financing arrangement by the project company. The incentive should have at least a moderate impact on the other utility electricity profile because, of course, it also contemplates large surface facilities, probably financed by debt (perhaps without the benefit of a loan guaranty). This incentive would tend to improve any utility's interest coverage ratio.

C.7. Income Tax Deferral

The Internal Revenue Code might be amended to provide for a deferral to later years of a certain percentage of the federal income tax which would otherwise be due on income from selected geopressured-geothermal development projects. This deferral would in many ways be similar to accelerated depreciation, except that it would not be couched as a mechanism by which to return the developer's capital investment in the project. Payment of the deferred taxes would be required at a future date, either without interest or with interest. Obviously, repayment without interest would be any developer's preference. There is currently no similar incentive available to the developer of any energy source.

This incentive is, in effect, a loan, albeit of the taxpayer's own money, from the government to the taxpayer; it would not, of course, appear on the corporate balance sheets as a "debt" item, nor would it require that the taxpayer come forward with collateral. This incentive should be anticipated to have a slight favorable impact on the development schemes postulated in the four gas production profiles. As to the pipeline and electric utility methane profiles, this may be a conservative estimate of the incentive's impact. The parent companies in each of these profiles are comfortable with debt financing and are probably particularly alert to take advantage of debt financing which does not harm their balance sheets; on the other hand, the taxes of the subsidiary in these two profiles are passed to the parent in the fuel purchase price and on to the customer as an operating expense, so the impact on corporate decision-making of subsidiary tax relief could be very small.

C.8. Current Deduction of Lease Acquisition and Exploration Expenses

The costs of acquiring geopressured-geothermal leases and conducting exploration activities on those leases preparatory to commercial development might be allowed as a current deduction from federal income tax liability, in the manner that intangible drilling costs are now allowed a current deduction. Present law is that these costs are only recovered (for unproductive properties) on abandonment and (for productive properties) through cost depletion.

This incentive should have a slight favorable impact on the four gas production profiles as it would provide a mechanism by which to more quickly recover costs. In the case of productive properties, this incentive would operate to reduce the cost of a geopressured-geothermal project in both the short and long terms because the costs recovered under this initiative could otherwise only be recovered through cost depletion, which would in all likelihood be foregone in favor of percentage depletion. The incentive is projected to have a moderate favorable impact on the other two profiles since the development schemes outlined in those profiles contemplate both higher lease acquisition and field definition expenses because reservoirs which will support the contemplated surface facilities would presumably underlie large surface areas and require more thorough definition for long-term, efficient, production.

+*C.9. Alternative Energy Property Tax Credit Extended to Utilities

The Internal Revenue Code might be amended to allow the additive ten percent alternative energy tax credit to be claimed on public utility property. Currently, public utilities may not claim this credit on equipment which they purchase to produce, distribute, or use energy derived from a geothermal deposit.

This incentive would have no impact on the gas production only profiles because those do not contemplate the purchase of alternative energy property by utilities. It would also have no favorable impact on the project company profile because the project company, not being a public utility, is not currently prohibited from claiming the alternative energy property tax credit and passage of this incentive would undermine one of the important rationales for the existence of a project company. Because the alternative energy property tax credit may be applied to offset one hundred percent of tax liability and because extensive utility-financed surface facilities are contemplated in the utility plant ownership profile, this incentive should have a significant favorable impact on that profile.

C.10. Allowance of Intangible Drilling Cost Deductions on Shallow Disposal Wells

The Internal Revenue Service might amend its regulations to allow the deduction of intangible drilling costs on shallow wells used for the injection of geopressured-

geothermal brines. Presently, IDC's are available only on production wells and on wells, not themselves production wells, which stimulate further resource recovery through production wells.

This incentive is projected to have no impact on the gas production only profiles because they do not contemplate the drilling of shallow injection wells. Deep injection wells, of course, stimulate further resource recovery. The incentive could be anticipated to have a slight impact on the profile variants in which the petrochemical firm or the integrated energy company elects to produce the resource in part for the net generation of electricity; this would entail the shallow injection of spent brine. The proposed incentive should have a slight to moderate impact on the utility electricity profiles. The impact is seen as no greater than this because the intangible costs of drilling shallow injection wells would comprise a relatively small percentage of the over-all cost of the project and ultimately would be borne by the electric utility ratepayers, anyway; of the two, the project company profile should be the more favorably influenced because of its more tenuous capital structure and because it could probably be structured to allocate the IDC's to limited partners in need of tax write-offs.

C.11. Removal of IDC's from Minimum Taxation

The Internal Revenue Code might be amended to exclude IDC's claimed on geopressured-geothermal properties from the category of items potentially subject to minimum taxation. Under current law, IDC's claimed on properties which produce geopressured methane and which are in excess of the deductions which would have been allowed had the IDC's been capitalized and recovered ratably are defined to be excess IDC's; to the extent that excess IDC's exceed net income from oil, gas, and geopressured methane properties they are items of tax preference and are subject to the minimum tax. Corporations, other than sub-chapter S corporations and personal holding companies, are not subject to the levy of this tax.

This incentive depends for its effectiveness on the manner in which the development of the geopressured-geothermal reservoir is financed. Only in the case where the production company is operating as a general partner using the equity input from limited partners and in return allocating to limited partners intangible drilling cost deductions on the development effort will this incentive have an impact. As written, none of the profiles except the one with a project company seems susceptible to this type of financing mechanism; therefore, the incentive should have no impact on those profiles. The profile in which the project company is the principal actor might experience a moderate favorable impact from this incentive, depending on the specifics of the project company's financing package. The impact of this incentive is not projected to be very great even for a project company because of the likelihood that equity investors in a geopressured development program would have other oil and gas income with which to offset excess IDC's from the geopressured project, and thereby escape imposition of the minimum tax.

C.12. Specially Defined Energy Property Tax Credit Extended to New Facilities

The Internal Revenue Code might be amended to allow the additive ten percent specially defined energy property investment tax credit to be claimed on process heat and boiler preheated equipment in new facilities. Currently, this credit is only available for equipment used in an existing industrial or commercial process installed in an existing industrial or commercial facility.

Because none of the principal profiles contemplates use of the geothermal component of the geopressured-geothermal resource for non-electric process applications, this incentive would not be expected to have an impact on any of those principal profiles. The variants in which the petrochemical firm and integrated energy company make some process use of the thermal component of the resource would be expected to experience moderate favorable impacts from this incentive. Because the alternative energy property investment tax credit is apparently intended to apply to heat exchangers, preheaters, etc., which are used for the generation of electricity, it is assumed that that tax credit is the one which would be of interest to parties to the utility electricity profiles.

D. IMPACT MATRIX (No impact = 0, Very significant impact = 4

In cells in which there are two numbers, the one following the slash relates to a profile variant.

B. RISK REDUCTION INCENTIVES

B.1.(a)	Federal Support of Reservoir Research and Development Projects
B.1.(b)	Insurance Against Early Reservoir Failure
B.1.(c)	Compulsory Unitization
B.2.	Insurance Against Subsidence or Aquifer Damage
B.3.(a)	Federal Support of Geothermal Electricity Generation and Process Heat Research and Development Projects
B.3.(b)	Geopressured Methane Exclusion from Curtailment
B.3.(c)	Geopressured Methane Exclusion from Incremental Pricing
B.4.	Loan Forgiveness-Surface Facilities Loan Forgiveness-Exploration and Confirmation
B.5.(a)	Common Carriage of User-Owned Geopressured Methane
B.5.(b)	Exemption from Utility Regulation
B.5.(c)	Current Rate Base Treatment of Geopressured-Geothermal Construction Work in Progress
B.5.(d)	Methodology for Allocating Costs Among Resource Components

C. EXPECTED VALUE INCENTIVES

C.1.(a)	Methane Production Credit
C.1.(b)	Geothermal Heat Credit
C.2.	Federal Support of <i>in situ</i> Methane Extraction Research and Development
C.3.	5-year Depreciation
C.4.(a)	Rate Base Treatment of Geopressured-Geothermal System Development Expenditures
C.4.(b)	Rate Base Treatment of Geopressured-Geothermal
C.5.	Crude Oil Excise Tax Exemption
C.6.	Interest Subsidy
C.7.	Income Tax Deferral
C.8.	Current Deduction of Lease Acquisition and Exploration Expenses
C.9.	Alternative Energy Property Tax Credit Extended to Utilities
C.10.	Allowance of Intangible Drilling Cost Deductions on Shallow Disposal Wells
C.11.	Removal of IDC's from Minimum Taxation
C.12.	Specially Defined Energy Property Tax Credit Extended to New Facilities

Petrochemical Firm

Pipeline Company

Integrated Energy Co.

Electric Utility Methane Production

Project Company

Utility Plant Ownership

2	2	2	2	3	4
0/2	0	0/2	0	2	4
1/2	1	1/2	1	2	2
1/2	1	1/2	1	2	3
1/2	1	1/2	1	4	4
1	3	2	1	0	0
0	3	2	0	0	0
0	0	0	0	1	3
2	2	2	2	1	2
3	0	2	3	0	0
0/3	0	0/3	0	0	0
0	0	0	1	0	2
0	0	0	0	1	1
3	4	3	3	3	3
1/3	1	1/3	1	3	3
2	3	3	2	0	0
2	2	2	2	3	2
0	1	0	1	0	3
0	3	0	3	2	4
0	3	4	0	2	0
1	2	1	2	3	2
1	1	1	1	2	2
1	1	1	1	2	2
0	0	0	0	0	3
0/1	0	0/1	0	2	1
0	0	0	0	2	0
0/2	0	0/2	0	0	0

E. GOVERNMENT EVALUATION OF INCENTIVES

Our discussion of incentive programs has focused almost entirely upon their effectiveness in encouraging the participation of private industry in the development of Gulf Coast geopressured-geothermal resources. We have emphasized that energy investments are evaluated by business primarily on the basis of two criteria; the potential profitability of the investment (rate of return) and the likelihood that this potential will be realized (risk). A major conclusion of this report is that the effectiveness of incentives during the early stages of resource development is dependent upon a balanced address of both of these concerns of business decision-makers.

Apart from these economic factors, our research has suggested additional incentive characteristics which will influence private participation in resource development. One recurring factor, evident in both on discussions with industry (Appendix B) and our survey of process heat users (Chapter VIII), is the degree to which the incentive involves the firm in direct interaction with government agencies. Generally, we found that the greater the degree of government involvement, the less desirable the incentive will appear to private industry. Thus an incentive which provides a credit through the existing tax system will be preferable to an incentive of equal magnitude in the form of a guaranteed product price, because the latter involves the government directly in the market process.

The criteria enumerated above for the evaluation of an incentive concern its effectiveness, from the perspective of private business, relative to that of other incentives. In addition to these criteria are several which do not affect the stimulus offered by the incentive, but rather the desirability of the incentive from the perspective of government. Most obvious of these criterion is the cost of the incentive. This is related to a separable criterion, the apparatus for incentive administration. Some of the incentives analyzed in this chapter, like FERC interconnection orders and federal income tax credits, could be administered under existing bureaucracies with some additional workload. Others, such as insurance programs and loan forgivenesses would require additional manpower for implementation and administration.

Another possible criterion of government incentive evaluation is the visibility of incentive costs. In order to maintain adequate control over the costs of government programs, it is desirable that these costs be clearly identifiable. Examination of the proposed incentives reveal large potential differences in this aspect; production credits are highly visible, tax items are submerged within complicated accounting arrangements, and the costs associated with insurance programs may remain unknown for years after the incentive is in effect.

Also important to the evaluation of potential government incentives to spur commercialization of an energy resource is the specificity of the incentives to the resource. Many of the incentives discussed in this chapter give geopressured-geothermal resources special treatment not accorded energy resources in similar stages of development. Production credits, exclusion of geopressured methane from incremental pricing, and avoidance of the proposed "windfall profits tax" on profits plowed back into geothermal energy are all examples of incentives which by their nature could be applicable to any resource. Were these incentives given to geothermal, parties with interests in other resources would push for equal treatment and, thereby, potentially diminish the relative stimulus of the original incentive. On the other hand, incentives such as insurance against subsidence damage have no direct counterparts in other resources and, thus, would not likely suffer dilution of their impact over time.

Finally, most incentive actions will have subtle effects in areas which are not immediately obvious. For example, compulsory unitization of geopressured formations may legitimize unitization in principle and, thereby, inadvertently bolster efforts to unitize conventional oil and gas formations. An exemption from the "windfall profits" tax for profits invested in geopressured energy development might greatly stimulate resource development, and insure that integrated oil and gas producers dominate that development.

Our examination of potential government incentives considers only their likely effects as inducements to the participation of private firms in the commercialization of geopressured-geothermal resources. The other criteria of incentive evaluation discussed here have not been considered in any depth; however, they should be by government policy-makers who contemplate going forward with specific incentives suggested here.

APPENDIX A

PARTICIPANT DESCRIPTIONS

A. INTRODUCTION

The listing below, by category and in alphabetical order, is of the many firms and associations who have previously shown interest in geothermal resource development. During the initial stages of this project a questionnaire survey was mailed requesting information pertaining to participant interests in geothermal development. An asterisk (*) to the left of a name indicates that the firm or association replied to the questionnaire. Those without an asterisk have otherwise shown interest in the resource by attending meetings and/or issuing reports on the subject.

B. ARCHITECTURAL ENGINEERING/CONSTRUCTION FIRMS AND GEOTHERMAL EQUIPMENT SUPPLIERS

* Bechtel Corporation, San Francisco, California, is interested in geopressured energy conversion and utilization in all three forms: gas, pressure, and thermal. It is currently conducting a modest in-house research program in advanced geothermal energy conversion, including geopressured. Bechtel is a subcontractor to SWRI on EPRI project RP1272-1, "Assessment of Economics and Technologies for Geopressured Energy Extraction." Bechtel has just submitted a proposal to EPRI to perform a two-year study, "Geopressured Energy Conversion - Preferred Systems," EPRI RFP No. 1671. Bechtel National is conducting a study sponsored by the Gas Research Institute to determine if enough data exists in the geopressured-geothermal area to make an in-depth reservoir assessment.

* The Ben Holt Company, Pasadena, California, is a consulting, engineering and construction firm serving the energy industry. Since 1972, they have been active in the design of facilities for electric and non-electric utilization of geothermal energy, primarily from hydrothermal reservoirs. They have made preliminary designs of facilities for maximizing energy recovery from geopressured-geothermal reservoirs. This includes thermal and kinetic energy and methane recovery. In addition to plant design expertise, the Ben Holt Company has a strong background in thermodynamics.

Brown and Root, Houston, Texas, is an engineering subsidiary of the Halliburton Company, and conducts major energy engineering and construction projects worldwide. Brown and Root is known especially in the construction of chemical and petrochemical plants and pipeline construction. It was a subcontractor to The University of Texas in 1975 on a project which developed designs for surface electricity generation facilities fueled by geopressured brine.

* Completion Technology Company, Houston, Texas, is an architectural engineering and construction firm operating internationally. Their specialty is engineering work on the completion phase of well development. They have been monitoring progress in the development of geopressured-geothermal resources since 1977.

DDS Engineers, Incorporated, Fort Lauderdale, Florida, has recently conducted a study sponsored by the DOE on geothermal energy. The final report, entitled "Preliminary Research on Geothermal Industrial Complexes," provides economic, technical and other information on developing industrial complexes to utilize geothermal energy.

* The Geothermal Power Company, Incorporated, Elmira, New York, designs and manufactures well-head power generators using geothermal steam. It is a worldwide operation with interests in geothermal dating prior to 1975. The organization sees a future potential for a total flow well-head power plant that could be utilized by the geopressured-geothermal energy source.

Intercomp Resource Development and Engineering, Incorporated, Houston, Texas, is assisting SWRI in a study of the feasibility of commercial scale electric generation from the Gulf Coast geopressured-geothermal resource.

* McCulloch Geothermal Corporation, Los Angeles, California, participated in development of geothermal resources in California and Utah. They are currently maintaining a general interest in the Gulf Coast geopressured-geothermal activities.

The McDermott-Hudson Engineering Corporation, Houston, Texas, are designers and builders of hydrocarbon processing facilities. They have interests in other types of thermodynamic and chemical processing which are energy-related. Since 1977, personnel have attended geopressured-geothermal conferences.

* Rogers Engineering, San Francisco, California, is an architectural engineering firm which has managed construction of several geothermal power plants in California and foreign countries.

C. CONSULTANTS: LEGAL AND FINANCIAL, RESEARCH AND DEVELOPMENT, ENVIRONMENTAL, AND PETROLEUM GEOLOGY AND ENGINEERING

C.1. Legal and Financial

* Geothermal Energy Corporation, New York, New York, is a concern that designs and implements financing packages to support the developing financial requirements of both the electric and non-electric geothermal industry. The GEC has been active since before 1975 in investment designs in California, Nevada, and Oregon.

* Geothermal Financial Consultants, Carson, California, provides technical, managerial, and financial consulting services to geothermal and prospective geothermal companies in the development of geothermal properties in the western states and geopressured properties in Louisiana. Since 1976, employees of Geothermal Financial Consultants have also attended conferences, developed information, and made plans to participate in the development of new geothermal technologies.

* LaRue, Moore, and Schafer, Dallas, Texas, is a consulting firm whose interest in the geopressured-geothermal resource development dates prior to 1975.

* The Law Offices of Duncan M. Smith Jr., Lafayette, Louisiana, in 1976 handled the legal aspects of leasing and obtaining use of a well for geopressured-geothermal testing during 1977 in Southern Louisiana. Mr. Smith also organized and assisted the corporation which supervised the subsequent well testing. During the Third Geopressured-Geothermal Energy Conference held at the University of Southern Louisiana in 1977, Mr. Smith participated as the legal section chairman.

C.2. Research and Development

* Sandia Labs, Albuquerque, New Mexico, is currently monitoring the development of the geopressured-geothermal resource, with special interest in drilling technology.

* Science Applications, Incorporated, Morgantown, West Virginia, is a research and development consulting firm serving the entire United States. Since 1977, they have been monitoring activities surrounding the development of the geopressured-geothermal resource as well as attending conferences on the subject.

* Southwest Research Institute (SWRI), San Antonio, Texas, conducts contract research and development programs for industry and government. SWRI was recently awarded a Contract (RP 1272-1) on the Electric Power Research Institute's (EPRI) project to assess the feasibility of developing commercial scale generation of electric power from the geopressured-geothermal resource. SWRI's main interest in the geopressured-geothermal resource is in the area of technology assessment.

Systems, Science, and Software (S³), La Jolla, California, has recently re-run a computer simulation program parallel to that of The University of Texas at Austin in which initial reservoir predictions incorporating recent data on compaction coefficients obtained at the Center for Earth Sciences and Engineering were used. S³ and UT obtained the same percentage reservoir depletion recoveries.

* TWR Energy Systems Group, McLean, Virginia, is engaged in a systems study to assess the potential recovery of methane from hot, geopressured brines in the Gulf Coast area. The scope of the effort includes primary production mechanisms, waste water disposal and utilization of methane and associated geothermal energy.

* Tura Tek, Incorporated, Salt Lake City, Utah, is a research and development firm with prime interest in energy. In particular, the firm has been involved in problem-solving for development of unconventional resources. Since 1977, personnel have attended geothermal conferences and have worked developing more information on the resource.

C.3. Environmental

CK GeoEnergy Corporation, Las Vegas, Nevada, is an engineering and consulting firm presently under contract with the Department of Energy to sponsor meetings reviewing the current developments in geopressured-geothermal energy research. They also publish a monthly status report on the DOE/Industry Geopressured-Geothermal Energy Development Program.

Coastal Environmental Incorporated, Baton Rouge, Louisiana, is a consulting firm which prepares environmental assessment and statements. They do basic research and planning for energy-related facilities, as well as general land use planning. Since 1976 Company personnel have attended conferences and otherwise been active in assessing the organization's role in the development of the geopressured-geothermal resource.

Ecology and Environmental, Incorporated, with a home office in Buffalo, New York, is a multi-disciplinary world-wide organization with capability to do studies in all fields of environmental concern. They have particular qualifications in the energy fields (refineries, pipelines, strategic petroleum reserves, LNG facilities and shipping). Since 1978 Ecology and Environment, Inc. has shown interest in the development of geopressured-geothermal energy as well.

Radian Corporation, Austin, Texas, assisted as a contractor on the air quality and noise monitoring studies at the Brazoria county geopressured-geothermal test well. Radian has also done work in the geothermal field of space heat. They provided assistance in the development of geothermal space heating uses for Navarro Junior College, Corsicana, Texas.

Research and Planning Consultants (RPC), Austin, Texas, has done geothermal work under contract for the Texas General Land Office. They authored "Geopressured-Geothermal Resource Development on Public Force School Lands," an outline of economic, environmental, and social issues related to geopressured development.

C.4. Petroleum Geology and Engineering

* Mr. H. F. Dunlap, Wimberley, Texas, is a consultant on geothermal production problems, particularly in well logging, and in overall systems economics. Mr. Dunlap is a retired petroleum engineer, and a visiting professor at the University of Texas Department of Petroleum Engineering. His interest in the development of the geopressured-geothermal resource dates prior to 1975.

* Mr. George R. Gray, Bellaire, Texas, is a drilling technical consultant who recommends drilling fluid programs for various drilling operations. His interest in the geopressured-geothermal resource dates prior to 1975 and continues to present.

P.H. Jones Hydrogeology, Incorporated, Baton Rouge, Louisiana, has been a major participant in the development of the geopressured-geothermal resource in the state of Louisiana.

The firm of Osborn-Hodges-Roberts-Weiland, Bryan, Texas, is a petroleum engineering-consulting organization. They were the prime Contractor to the Department of Energy on the first Louisiana geopressured test well, the Edna Delcambre Number One. They have been active in geopressured-geothermal development since 1975.

Raba and Associates Consulting Engineers, Inc., San Antonio, Texas, is a geo-technical engineering, construction materials, and testing firm operating in Texas. Interests include shallow exploration and monitoring well installation and design. Raba and associates have been providing engineering services and solving new problems associated with the geopressured-geothermal resource. They have been monitoring activities along the Gulf Coast since 1975.

The Ryder Scott Company, Houston, Texas, is a petroleum engineering consulting firm. The company is comprised of engineers and geologists engaged in providing total reservoir engineering and geological services to the oil and gas industry on a world-wide basis. They are currently working with one client in geopressured-geothermal research and development activities, and are continuing to monitor geopressured-geothermal activities elsewhere.

The Williams Brothers Engineering Company, Tulsa, Oklahoma, is a world-wide energy resource consulting firm. Since 1977 employees have attended conferences, and monitored the on-going research in the development of geopressured-geothermal energy.

D. GAS OR ELECTRIC UTILITY

Arkansas-Louisiana Gas Company, Shreveport, Louisiana is a natural gas supplier for Louisiana and Arkansas and most of Eastern Texas. The company has sent representatives to attend geopressured-geothermal conferences.

* Bay State Gas Company, Canton, Massachusetts, is a distributor of natural gas, propane, SNG and LNG in New England. It has subsidiaries exploring for gas and oil, developing gas storage fields and manufacturing insulation. Interest in the geopressured-geothermal resource would be as a potential supply diversification opportunity.

* Brooklyn Union Gas Company, Brooklyn, New York, sees the geopressured-geothermal resource as a future long-term supply of natural gas for the gas industry in general, and BUG in particular. Currently BUG is participating in the Institute of Gas Technology's project to evaluate the Brazoria County (Texas) well.

Central Louisiana Electric Company, Lafayette, Louisiana, has sent representatives to attend geopressured-geothermal conferences.

Central Power and Light Company, Corpus Christi, Texas, has contributed to the ongoing research for commercial development of the geopressured-geothermal resource.

Cities Service Company, Tulsa, Oklahoma, is a major supplier of natural gas through its pipeline network. Employees have attended geopressured-geothermal conferences.

* Columbia Gas, Columbus, Ohio, is currently supporting research in the field for developing the geopressured-geothermal resource.

El Paso Natural Gas Company, El Paso, Texas, is a major natural gas transmission company with varied interests in energy development. El Paso company employees have attended conferences on the geopressured-geothermal resource development.

Gulf States Utilities Company, Beaumont, Texas, has contributed to the ongoing research into the commercial development of the geopressured-geothermal resource. Representatives have attended numerous conferences and meetings, as well as monitoring research findings.

Houston Lighting and Power Company, Houston, Texas, has contributed to the ongoing research into the commercial development of the geopressured-geothermal resource. Representatives have attended numerous conferences and meetings, as well as monitoring research findings.

Houston Natural Gas Company, Houston, Texas, has maintained a high interest in the continuing research and testing of the geopressured-geothermal resource. Company representatives have recently served on an advisory committee, and have also attended numerous meetings and conferences to discuss aspects of the geopressured-geothermal research.

* Kansas-Nebraska Gas Company, Lakewood, Colorado, is a gas utility serving customers in Wyoming, Colorado, Nebraska, and Kansas. Personnel have monitored the developments in the geopressured-geothermal resource since 1975.

Lone Star Gas Company, Dallas, Texas, provides gas for customers in the north central Texas region. Lone Star Gas is a subsidiary of Ensearch, Incorporated, and is monitoring the developments in the ongoing geopressured-geothermal research project.

Magma Power Company, Escondido, California, was founded as the first electricity generator from geothermal sources in the United States. They began the development in the Geysers area of California, and through their subsidiary, Magma Gulf Company, Baton Rouge, Louisiana, have diversified their interest into the geopressured-geothermal resource development as well.

National Gas Pipeline Company of America, Chicago, Illinois, has sent representatives to attend geopressured-geothermal conferences.

* North Illinois Gas, Aurora, Illinois, is a gas utility serving customers in northern Illinois. Their interest in the geopressured-geothermal resource is to ensure a supply of energy to their pipeline system for their customers.

* Northern Natural Gas Company, Omaha, Nebraska, is a wholesale purchaser, transporter and seller of natural gas to customers in the north central US. Principal interest in the geopressured-geothermal resource is for the methane.

* San Diego Gas and Electric Company, San Diego, California is singularly directed toward electric power generation from hydrothermal resources.

Texas Eastern Transmission Company, Houston, Texas, has maintained interest in the ongoing research into geopressured-geothermal resource development. Company representatives have participated in various meetings and conferences in the recent past.

Texas Utilities Services Incorporated, Dallas, Texas, is the holding company for Dallas Power and Light. The Company has contributed to the geopressured-geothermal research program.

Transco Energy Company, Houston, Texas, has participated directly in the ongoing geopressured-geothermal research project. The Company waived rights to patents on stripping methane for the benefit of research findings and resource development.

United Gas Pipeline, Houston, Texas, has contributed to the ongoing research program in geopressured-geothermal resource development. Company representatives have participated in various conferences and meetings in the past.

E. MANUFACTURERS

* B & K Engineering, Incorporated, Baltimore, Maryland, is a specialist in the development of heat pipe hardware for both aerospace and ground application. Since 1976, personnel from B & K Engineering have attended geothermal conferences and sought to develop information in geothermal technology. They have originated two-phase heat transfer concepts which have unique application and offer substantial gains in geothermal applications.

* E. I. Dupont de Nemours and Company, Wilmington, Delaware, is a world-wide manufacturer of chemicals and polymers. Prior to 1975, Dupont began monitoring the possibilities of developing the geopressured-geothermal resource as a source of natural gas. As a large consumer of natural gas for processing and feedstock, Dupont remains generally interested in all new potential natural gas sources.

* E-Systems Incorporated, Dallas, Texas, manufactures products related directly to conversion of solar energy. They maintain an interest in geothermal from the standpoint of development of surface equipment, energy conversion equipment, and systems integration equipment.

International Nickel Company, New York, New York, participated in 1978 in a corrosion research program conducted at the geopressured-geothermal well site. INCO provided several corrosion test spools for use in different geothermal environments.

* Kaiser Aluminum and Chemical Corporation, Oakland, California, is a manufacturer of primary aluminum. KACC operates several plants in the state of Louisiana which consume large quantities of natural gas, and therefore maintain a great interest in any new source of indigenous energy.

* NL Atlas Bradford is a supplier of high pressure connectors for oil field down-hole tubing and casing. Their products are seen as critical to the future development of geopressured energy.

* PPG Industries, Inc., Industrial Chemical Division, Lake Charles, Louisiana, is a large producer of caustic-chlorine. They also operate a large solvent facility utilizing chlorine and ethylene, and a silica pigment plant. PPG has been monitoring geothermal information and attending conferences since 1975.

F. OIL, GAS, AND GEOTHERMAL EXPLORATION AND PRODUCERS

Amoco Production Company, New Orleans, Louisiana, has sent company representatives to conferences on the development of the geopressured-geothermal resource.

Atlantic Richfield Oil Company, Lafayette, Louisiana, has indicated interest in the findings of the research on the geopressured-geothermal resource. Company representatives have attended conferences at various times.

* Aquitaine Company of Canada Ltd., Calgary, Alberta, is primarily engaged in exploration for and production of oil and gas in Canada, and through its subsidiary, Al-Aquitaine, explores for oil and gas in the northern United States, and produces coal in Pennsylvania. Aquitaine is interested in opportunities in the energy production field and thus is interested in geopressured-geothermal energy development.

* Big Chief Drilling Company, Oklahoma City, Oklahoma, is an oil and gas producer and a drilling contractor. Big Chief is a subsidiary company of Entex Incorporated. Since 1976 they have monitored developments in the geopressured-geothermal resource and have sent personnel to attend various conferences on the subject.

* Chevron Resources Company, San Francisco, California, is a division of Chevron Industries, Inc., a wholly-owned subsidiary of Standard Oil Company of California. Chevron Resources actively explores in the western US for geothermal resources which can be used to generate electricity. Currently they are developing the Heber Geothermal Field in the Imperial Valley of California to supply geothermal fluid to a 50-megawatt plant being built by Southern California Edison Company. Chevron Resources' interest in geopressured-geothermal is to determine its potential to generate electricity.

* Chevron, U.S.A., New Orleans, Louisiana, is interested in determining the potential for dissolved methane in the geopressured-geothermal resource. Currently Chevron is monitoring developments and activity in the geological evaluation of the resource.

* Columbia Engineering Corporation, Wilmington, Delaware, produces, buys, sells, stores, transports, and refines natural gas and serves about 10 percent of the nation's gas customers. Columbia sells gas at wholesale and retail in Ohio, Pennsylvania, West Virginia, Kentucky, Virginia, New York, Maryland, and the District of Columbia. The company has been monitoring geopressured-geothermal developments because it views the methane content as a potential commercial source of gas supply for the company's customers. *

* Continental Oil Company, Houston, Texas, continues to monitor developments in the geopressured-geothermal resource.

* CSG Exploration Company, Oklahoma City, Oklahoma, is a subsidiary of Cities Service Gas Company. CSG Exploration develops and provides natural gas to its parent, which provides gas to Kansas, Nebraska, Oklahoma, and Missouri. The CSG Exploration Company has been monitoring geopressured-geothermal developments with interest since 1977 because of the potential methane contained in the resource.

* Exxon Company, U.S.A. and Exxon Production Research, Houston, Texas, have sent representatives to geopressured-geothermal conferences and meetings. The companies are monitoring the developments of the test drilling in Brazoria County, Texas.

General Crude Oil Company, Houston, Texas, is the main drilling contractor for the Department of Energy sponsored geopressured-geothermal test well, Pleasant Bayou #2, recently completed in Brazoria County, Texas.

Gruy Federal, Incorporated, Houston, Texas, has of recent initiated an intensive program of monitoring all deep wells, seeking to participate in DOE's "Wells of Opportunity" program. As of April, 1979, this effort paid off. The Neuhooff Oil and Gas Corporation #2 Fairfax Foster Sutter well in Louisiana has become the first well turned over to the DOE program.

* Gulf Science and Technology, Pittsburg, Pennsylvania, is a world-wide energy exploration and production company. Since 1977, employees have attended conferences on the geopressured-geothermal resource and the company has otherwise monitored development.

* Howell Drilling Incorporated, San Antonio, Texas, does both contract work and inhouse exploration for oil and gas. As a drilling company already serving the Texas Gulf Coast, Howell is closely monitoring developments in the geopressured-geothermal resource.

- * Louisiana Land and Exploration Company (LL&E), New Orleans, Louisiana, is an oil and gas exploration and production company. LL&E is a large land owner in South Louisiana and is interested in the potential development of the geopressured-geothermal resource in the area. Since 1977, employees have attended conferences and monitored events in geopressured development.
- * Mobil Oil Corporation, Denver, Colorado, continues to monitor developments in the geopressured-geothermal resource. Mobil purchased General Crude Oil and its properties from International Paper Company in 1979.
- * M.R.T. Exploration Company, St. Louis, Missouri, is a subsidiary of the Mississippi River Transmission Corporation. Their main objective is to explore for and produce natural gas for the parent company's primary market in St. Louis, and are thus interested in geopressured methane.
- * Pennzoil Company, Houston, Texas, is interested in the geopressured-geothermal resource for its potential methane content. They have been monitoring developments since 1978.
- * The Phillips Petroleum Company, Bartlesville, Oklahoma, is interested in the commercial aspects of the geopressured-geothermal methane. Currently they are monitoring Department of Energy results from the Brazoria County well.
- * SEDCO, Incorporated, Dallas, Texas, is a drilling contractor for both offshore and onshore operations. SEDCO owns and operates 30 offshore drillings and semi-submersible drilling rigs which work on a world-wide basis. SEDCO also owns and operates 45 land rigs primarily in Iran, Algeria, and Saudi Arabia. If present testing shows promise, SEDCO will combine the expertise of their Drilling Division, Oil and Gas Division, and Process Design group to develop geopressured methane.
- Shell Oil Company, Houston, Texas has sent representatives to the geopressured-geothermal conferences held in the recent past.
- Sohio Petroleum Company, Oklahoma City, Oklahoma, has sent representatives to geopressured-geothermal conferences.
- * Southland Royalty Company, Fort Worth, Texas, is an oil and gas producer. Southland is presently diversifying into geothermal energy.
- * South Louisiana Production Company, Incorporated, Lafayette, Louisiana, is an oil and gas producer affiliated with a gas and electric utility. Their drilling operations in recent years have been involved with deep, high pressure, high-temperature zones in the "Tuscaloosa Trend" of central Louisiana. They are interested in learning what the economic potential of geopressured zones may be.
- * Sunmark Exploration Company, Dallas, Texas, is a subsidiary of Sun Co., Incorporated and is interested in exploration for gas and oil worldwide, except Canada. SUNEDCO, another subsidiary, is interested in geothermal energy and Sun Gas is interested in gas production. Each is a separate company headquartered in Dallas. They all have been monitoring geopressured-geothermal developments since 1976.
- * Sunoco Energy Development, Geothermal Division, Dallas, Texas, is a geothermal resources producer operating in the contiguous USA. Since 1976, Sunoco has been interested in the development of the geopressured-geothermal resource, and accordingly has made an assessment of the organization's future options regarding the resource.
- * Texaco, Incorporated, Houston, Texas, is currently monitoring the progress of the geopressured-geothermal well in Brazoria County. Their primary interest is in the methane contained in the resource.
- * Thermogenics, San Francisco, California, is a leading geothermal exploration and development company and a wholly owned subsidiary of Hughes Aircraft Company. In The Geysers area of California their geothermal discoveries have resulted in a contract with Pacific Gas and Electric Co. that includes the construction of a 55-megawatt power plant. In November, 1978, the geysers plant #15 will make them the second company in the US to generate revenue from geothermal production. In addition to developing 20,000 acres in California, they are negotiating for the acquisition of several other geothermal properties in the western United States.

Union Oil Company of California, Los Angeles, California, is active in that state's geothermal development. Union Oil has also monitored developments in the geopressured-geothermal resource along the Gulf Coast. They have sent representatives to numerous conferences and meetings.

G. OIL FIELD SUPPLY/SUPPORT COMPANIES

* AMF Tuboscope, Houston, Texas, is currently monitoring geopressured-geothermal activities in the area of corrosion research. Although they are not currently active along the Gulf Coast, they are participating in geothermal projects in California, Idaho, North Dakota, and France.

Birdwell Division of Seismographic Service Corporation provided the software for the vertical seismic profiling data compiled for the geopressured-geothermal wells, Pleasant Bayou #1 and #2, in Brazoria County, Texas.

The Dresser-Atlas Company provided drilling equipment for the drilling of the geopressured-geothermal test well at Pleasant Bayou, Brazoria County, Texas.

* Eaton Industries of Houston, Texas, supervised the drilling of the geopressured-geothermal test well at Pleasant Bayou. Eaton is both a support company and an oil and gas producer. They began work in geopressured-geothermal resource development in 1977.

* Geothermal Services, Incorporated, San Diego, California, is a geophysical service company which provides turnkey heat flow programs, shallow and intermediate depth drilling, borehole logging, and consulting services to the geothermal industry. They have been actively developing the geothermal resource in the western United States since prior to 1975. GTS currently is monitoring the geopressured-geothermal development along the Gulf Coast.

Halliburton Services, Duncan, Oklahoma, is part of the Halliburton Company (corporate office: Dallas, Texas). Halliburton Services is one of four principal categories of operations. Through the oilfield services and products group the company provides world-wide specialized services required for the drilling, completion, and production of oil and gas wells, onshore and offshore. Because of similar drilling operations, the Halliburton Company has been active in the geopressured-geothermal well program.

* B. J. Hughes, Incorporated, Lafayette, Louisiana, is an oil well service company. Hughes, Inc., is active in cementing, acidizing, sand control, scale and corrosion inhibition, and fracturing services. They are currently monitoring activities and developing products and techniques for geothermal energy.

* The Hydril Company, Houston, Texas, manufactures blow-out preventers and machines and specialty connections for casing and tubing. Currently personnel are monitoring geopressured-geothermal activities as a future market area for Hydril's products.

* Louis Records and Associates, Lafayette, Louisiana, is an oilfield supply/support company. They both consult on well completions with drilling contractors, and act as a drilling contractor directly. They specialize in The Texas-Louisiana Gulf Coast region, and thus monitor geopressured-geothermal activities closely.

Schlumberger, Houston, Texas, provides both well servicing and long-spaced sonic logs with digital waveform recording and supplemental gamma ray logs to measure the elastic properties of sediments at the geopressured-geothermal well site in Brazoria County, Texas.

* Smith Tool, Division of Smith International, Irvine, California is a major manufacturer of drilling tools worldwide. Since 1976 they have monitored geothermal operations to provide products as development needs are specified.

* Weintritt Testing Laboratories, Lafayette, Louisiana, is an independent testing laboratory providing drilling fluid and production chemical testing as well as product evaluations and development. Their interest in the geopressured-geothermal resource is primarily as a testing and research laboratory assisting manufacturers in the development of products for the new market.

* W-K-M Wellhead Systems, Incorporated, Shreveport, Louisiana, is a leading supplier of wellhead equipment and valves, including safety systems for the oil and gas and geothermal industries. W-K-M currently supplies the major portion of geothermal wellhead systems production equipment around the world.

H. RESEARCH INSTITUTES

Battelle Northwest Laboratories, Richland, Washington, is currently active in assessing the economics of the western geothermal resources. With the Battelle Human Affairs Research Center, Seattle, Washington, BNL has published a recent article in the Energy Review, entitled "The Promise of Geothermal Energy Systems."

* Dunn Geoscience Corporation, Lathan, New York, maintains a general interest in geothermal energy. They are currently active in the northeastern United States and have recently begun to monitor developments in geopressured-geothermal energy.

Electric Power Research Institute (EPRI), Palo Alto, California, is supported by the electric power industry, and provides in-depth research for their sponsors. EPRI has recently supported research on the technical assessment of electrical power generation on a commercial scale with geopressured-geothermal energy. EPRI personnel also maintain contact with researchers in the geopressured field and attend the various conferences throughout the United States.

Gas Research Institute, Chicago, Illinois, maintains interest in the development of the geopressured-geothermal resource. GRI has sponsored meetings in which geopressured-geothermal researchers participated.

* Johns Hopkins University Applied Physics Lab, Laurel, Maryland, (APL/JHU) has served since 1976 as the regional operations contractor for DOE/DGE for the eastern United States, excluding the geopressured regions of Texas and Louisiana. In that capacity they briefly studied the Gulf Coast, quantifying the magnitude of potential hydrothermal resources and the energy market in the area.

* Hudson Institute, Incorporated, Croton-on-Hudson, New York, contracts with the Department of Energy in the subject area of energy policy research. Institute personnel have thus attended geothermal conferences as well as contacted people to develop information on the resource.

* The Instituto de Investigaciones Electricas, Mexico City, Mexico, provides research and technology development support to the Mexican nationwide electrical utility, Comision Federal de Electricidad. One of the interests of IIE is geothermal energy and they are currently working on several internal projects, as well as one other under contract with CFE.

Institute of Gas Technology (IGT) Chicago, Illinois, is carrying out a number of programs in geopressured-geothermal resources development. For the DOE they are looking at economic sensitivities of various parameters in geopressured-geothermal projects and studying the effects of gas saturation on viscosity at high pressures and temperatures. They are also building a test facility and studying cores from geopressured well sites.

International Institute of Applied Systems Analysis (IIASA), Schloss Laxenburg, Austria, sponsored in June, 1979, a meeting between a US delegation and one from the Soviet Union National Academy of Sciences to discuss the geology of geopressured basins.

Lawrence Livermore Laboratories (LLL), Livermore, California is operated by the University of California under a contract with the Department of Energy. LLL's main work has been in nuclear, but the lab's broad resources has allowed a build up of basic science which is applicable to many energy fields. Such programs currently represent more than half of LLL's efforts.

Policy Mathematics Research, Incorporated, in July, 1978, gave a seminar sponsored by the Department of Energy on Unconventional Gas.

Los Alamos Scientific Laboratory, Los Alamos, New Mexico, has beginning studies underway in support of DOE's geopressured-geothermal program in brine thermodynamics and in brine transport. Research on simulated temperature and pressure will study

the equilibrium distribution between brines, methane and reservoir rock. Other studies will explore mass transfer processes, concentrating on those processes that tend to limit brine production.

I. UNIVERSITIES AND COLLEGES

* The Gulf University Research Consortium, Bellaire, Texas, is a multi-university consortium that has been dedicated to the research aspects of geopressured-geothermal energy development. Their effort was begun prior to 1975 and continues today. The consortium has produced a written assessment of the resource, and continues to monitor other research efforts, as well as attend conferences and meetings.

* Lamar University, Beaumont, Texas, is active in the study of land subsidence caused by fluid pressure decline. Professors and researchers from Lamar University have participated in conferences and meetings on this subject as it pertains to the geopressured resource.

Louisiana State University, Baton Rouge, Louisiana, has major contracts with the Department of Energy to research the development of geopressured-geothermal energy in the state of Louisiana. The LSU concept is to bring together many backgrounds and disciplines to bear on the major problems of developing the resource. LSU recently reported on five potential Louisiana sites for proposed drilling of a geopressured well.

* McNeese State University, Lake Charles, Louisiana, was the prime contractor in the early stages of site selection for the Edna Delcambre test well in Vermillion Parish, Louisiana. McNeese was responsible for the chemical analysis of all gas and fluids taken from the well. A final report has been published on the analyses. Currently, professors and researchers from McNeese have other proposals submitted to the Department of Energy to do similar analyses of waters from future geopressured-geothermal wells in Louisiana.

* Southern Methodist University, Dallas, Texas, has prior to 1975 researched the subjects of seismic anomalies, subsidence, and other environmental effects the development of geopressured-geothermal energy might have. Currently, SMU professors and researchers are assisting private sector organizations to understand the potential for and barriers to resource development. They are also continuing work in tectonic monitoring.

University of Southwestern Louisiana, Lafayette, Louisiana, sponsored the Third Geopressured-Geothermal Energy Conference held November, 1977. This conference, like their continuing research projects, was designed to look at the geopressured-geothermal resource in all of its aspects: geological, legal, engineering, environmental, and economic.

The University of Texas at Austin, Center for Energy Studies (Geothermal Division) and the Bureau of Economic Geology have a major continuous research program funded largely by the Department of Energy on the development of geopressured-geothermal resources along the Texas Gulf Coast. The program operates in conjunction with the Department of Energy's geopressured-geothermal drilling program in Texas. The various areas of interest in the geopressured program include: geologic assessment; environmental; elastic rock properties; resource utilization; metallurgy; electric power; process heat; operations research; legal and institutional; sandstone diagenesis; entrained methane; resource engineering; rock-mechanics; reservoir simulation; well design; well testing; reinjection; data base; and logging. There are a total of twenty-five principal investigators and two hundred staff and graduate students participating in the research effort.

There are numerous universities and colleges throughout the U.S. that have shown interest in the development of the geopressured-geothermal resource. Many have participated in the various conferences and meetings and some have at one time or another conducted research related to the resource development. Below is a list of some of the known institutions of higher learning that have participated in some way in the development of geopressured-geothermal energy.

Louisiana Tech University
Ruston, Louisiana

Stanford University
Stanford, California

University of Alabama
University, Alabama

Rice University
Houston, Texas

Texas A & M University
College Station, Texas

University of Houston
Houston, Texas

University of Louisville
Louisville, Kentucky

University of Oklahoma
Norman, Oklahoma

University of Texas:
Arlington

University of Kentucky
Lexington, Kentucky

University of Southern
Mississippi
Hattiesburg, Mississippi

Dallas
El Paso

J. OTHER

American Association of Petroleum Geologists has sponsored for some years the Distinguished Lectures Program, which has included lectures on the geopressured-geothermal resource.

* American Gas Association, Arlington, Virginia, represents the transmission and distribution companies of the gas industry. Interests include all potential supplies--cost, volume, capital requirements, legislative needs, and regulatory problems. Staff members of the AGA have since 1976 attended geothermal conferences as well as published several articles on geopressured gas resources in their journal the Gas Supply Review.

Dow Chemical, Houston, Texas, as a subcontractor to the University of Texas, prepared an authoritative economic analysis of flash steam electric generation from geopressured brines. Dow has also applied to the DOE for a contract to drill a geopressured well in Southern Louisiana.

Ocean Industries Magazine, Houston, Texas, is a trade and professional journal which publishes articles dealing with the exploration and production of minerals off shore. Since 1976 Ocean Industries has published articles on the geopressured-geothermal resource in the Gulf Coast region of the US.

The National Conference of State Legislatures, Denver, Colorado, and Washington, D.C., formed from three previously existing legislative organizations in January 1975, is the only nationwide organization representing all state legislators and their staffs. The NCSL published a report on state policies for geothermal development in late 1976. This report reviewed for the states various technical, economic, and institutional aspects of geothermal development. The NCSL has undertaken another geothermal policy project under Department of Energy funding. This project is intended to provide advice and assistance to state legislatures to help them resolve problems that impede the production and use of geothermal resources.

The Society of Petroleum Engineers in October, 1978, presented a geopressured session at the SPE annual meeting in Houston, Texas. Five papers were presented on on-going research by University of Texas researchers, Transco Energy, and Louisiana State University researchers.

* United Nations Institute for Training and Research (UNITAR), New York, in its Production for the Future is very much involved in studying energy resources for the future. UNITAR recognizes geopressured-geothermal as a potential source of energy world-wide. They have followed activities world-wide relating to the geopressured zones and are interested in organizing the first international conference on geopressured energy.

APPENDIX B

EXECUTIVE SUMMARY: INDUSTRY PERSPECTIVES ON RESOURCE DEVELOPMENT

INTRODUCTION

The Division of Technology Forecasting and Assessment at the University of Texas Center for Energy Studies conducted a Department of Energy-funded study which, among other things, examined government actions which might be taken to promote development of the geopressured-geothermal resources along the Texas Gulf Coast. Because of the Division's interest in incentives programs, we were asked by Mr. Randall C. Stephens, representing the federal government's Interagency Geothermal Coordinating Council, to arrange meetings for him with members of industry and state government who would be interested in discussion of a geothermal omnibus bill.

The Interagency Geothermal Coordinating Council is a statutory council composed of representatives of various federal agencies which have jurisdiction over activities related to geothermal development. For the past few years one of its subunits, the Institutional Barriers Panel, has been collecting information on possible legislative and regulatory changes which might speed the development of the nation's geothermal resources. Mr. Stephens chaired the panel and had been shaping its work into draft legislation to be sponsored by the Interagency Geothermal Coordinating Council in the current session of Congress.

To date, information for this legislation had been provided by people primarily interested in development of geothermal resources in the western states. However, the Institutional Barriers Panel also sought input regarding the Gulf Coast geothermal resources.

In response to Mr. Stephen's request and because the Division team also wished to hold discussions on the same subjects with interested groups, meetings were organized and held December 5 and 6, 1978, in the Federal Building in downtown Houston, Texas. Participants with similar interests were organized into small groups to avoid undue imposition on their time and to encourage detailed discussions. The following groups and meeting times were chosen:

1. Electric Utilities and Architectural Engineering Firms-
9:00 a.m. to noon, December 5,
- * 2. Large Industrial Energy Consumers-
1:30 to 4:30 p.m., December 5,
3. Gas Transmission and Distribution Companies-
9:30 a.m. to noon, December 6, and
4. Energy Production Companies and Financial Institutions-
1:30 to 4:30 p.m., December 6.

OVERVIEW OF THE MEETINGS

Dr. John H. Vanston, Jr., principal investigator in the Division's study, began each of the four meetings by introducing Mr. Stephens and welcoming each of the participants. He then introduced the other members of the Division team.

Mr. Stephens spoke extensively to the representatives about existing measures in the 1978 National Energy Act affecting geothermal development. He then introduced new proposals which might be included in a separate geothermal omnibus bill.

*Smaller industrial users of energy were surveyed by a questionnaire mailout. The results of this questionnaire are discussed in the text of this final report.

Mr. Stephens emphasized that it is not a defined goal of the Department of Energy to make the geopressured-geothermal resource development desirable, despite economic and technological factors, but rather the Department's objectives were to:

1. Define the nature of the resource
2. Determine whether it is a resource of value to the country, and, if so, within what time frame could it be commercially feasible
3. Initiate and expedite its development, if any, under near normal economic conditions and
4. Develop incentives to provide (a) limited, carefully constructed, permanent support based on environmental advantages and the indigenous nature of the resource, and (b) temporary support designed to cause normal development of the resource to occur earlier than it otherwise would.

Following Mr. Stephens' presentation, the remainder of each meeting was directed to general discussion of the omnibus bill topics and other related topics. Discussion focused on the impacts each mentioned incentive might have on individual companies as well as on the represented industries as a whole.

The topics of discussion were spontaneous and far-ranging as the purpose of the meetings was to generate ideas to aid in the formulation of policy. Nevertheless, as a matter of convenience for the reader, we have grouped these topics into four general areas: Economics, environment, policy reform, and research and development. Discussion of the meetings is summarized within this framework below.

ELECTRIC UTILITIES AND ARCHITECTURAL ENGINEERING FIRMS

Initially this group discussed extensively the default provision of the geothermal loan guaranty program. In this discussion, participants sought to clarify their positions to Mr. Stephens on the subject of default in general. The utility representatives explained that under no conceivable circumstances would they wish, much less be allowed, to default on any loan obligation. They reasoned that the requirements for utilities to go to the bond market for much of their financing subjects them to extensive and rigorous scrutiny. Thus any blemish on their credit record would have grave consequences on their bond ratings and increase the interest which they would be required to pay. Therefore, a guaranty which could only be executed by a default declaration would not stimulate their interest.

Under the general heading of economic incentives these representatives were in accord on four points. First, they agreed that a ten percent (10%) investment tax credit applicable to a hundred percent (100%) of a utility's tax liability would be a most welcome incentive. Next, they agreed that a restructuring of the Internal Revenue Service accounting procedures to allow rapid depreciation (3-5 years) for equipment used in geothermal energy was desirable. This should also include any equipment utilized above ground, such as a power generator. The third point of agreement suggested the creation of risk-sharing consortia, perhaps headed by architectural engineering firms, to reduce the exposure of the utilities to the great financial risk involved in geothermal development. Finally, all participants expressed concern over the subsidence problem which exists along the Gulf Coast resulting from shallow well groundwater withdrawal. They feared that deep well withdrawal of geopressured-geothermal fluids might possibly pose far more serious subsidence problems and felt that much more research in the area of land subsidence was necessary. This, of course, reflects an environmental problem, but they explained the occurrence of subsidence could be economically devastating, if the producing company were held liable. Therefore, the participants shared the opinion that some form of indemnity insurance should be made available to the companies which undertake geopressured-geothermal exploration, production, and/or utilization.

Under the category of research and development, the representatives felt that the federal government should support extensive research and development projects in all phases of geopressured-geothermal energy. Drilling one well at one site was certainly not enough to provide necessary investment information. Much more data was needed in subject areas ranging from current geological and environmental aspects of potential sites to the technological and economic prospects for successful utilization of the resource.

Within the topic area labelled Policy Reform three very specific points were made by the participants. Most important to them was an amendment to the 1978 Power Plant and Industrial Fuel Use Act that would allow geothermal methane to be used as boiler fuel for utilities. The rapid conversion to coal prescribed by this act will be an expensive and arduous task for utilities located along the Gulf. Allowing these utilities to continue to burn certain types of methane beyond the normal deadline would give the utilities more conversion time and allow them to spread capital expenditures over a longer period, thus keeping consumer costs down.

The second point in the policy reform area was the suggestion that hydro pressured methane wells be placed into the same category as geopressed methane wells. The feeling was that hydro pressured brine from "watered out" gas reservoirs could be pumped to the same type of gas extraction equipment envisioned for use on geopressed brines, thus creating another source of high cost methane. Utilizing these resources would not only provide a valuable additional supply of gas, but would also provide experience which would be of value in geopressed resource development.

Finally, the utility and architectural engineering firms saw a great need for a reduction and simplification of the processes required for compliance with governmental regulations. They indicated uneasiness about the number of regulations they are forced to comply with currently, and were unenthusiastic about the increased governmental control and the additional paper work that federal geothermal incentives might entail.

In summary the utilities were most interested in geopressed-geothermal energy for the methane it is thought to contain. They felt that allowing them to use this methane in their boilers would be the most significant incentive. Other incentive suggestions involved tax reductions, indemnity liability insurance, and the need for extensive research and development projects in all areas of geopressed-geothermal energy before commercial development is practical.

LARGE INDUSTRIAL USERS

This group included petrochemical and other companies which are large energy consumers. This group appeared more interested in the possibility of using the methane contained in the brines (if economical) than in any other aspect of the resource. While the industrial representatives were somewhat interested in possible geothermal heat applications, they felt that practical use of the water at the temperatures forecasted for the geopressed resource would be limited to special situations. In the more distant future, technical development might make utilization more attractive. Several participants commented that their companies currently had at least one source of low-grade heat which could not be economically employed.

Like the electric utilities, these large industrial users understand that they must eventually convert to coal as a fuel supply for process heat and steam generation. However, the industrial users did not foresee as many drawbacks to using coal as the utilities had. In fact, the chemical companies saw some advantages in converting to coal, principally in the production of certain by-products.

Another reason the industrial representatives expressed less interest in incentives for geopressed-geothermal resource development was the fact that, on the whole, the group felt that at this time the resource remains unproven. Opinion on this point varied from a totally pessimistic assessment of the resource's future viability, to the more general opinion that at the present time there are too many unknowns to properly evaluate the resource.

The primary recommendation of the industrial users, consistent with this line of thought, was for the government to invest substantial sums of money into geopressed-geothermal research and development projects. They specifically suggested the subject of hot water/heat application as an area in need of extensive work. In this area they felt that a preliminary market study might be useful. Sentiment was also expressed for the construction and operation, at government expense, of one or more demonstration plants.

A third area of concern to the industrial participants was the environmental effects of geopressed-geothermal development. Issues mentioned included subsidence and fresh water aquifer contamination through brine reinjection and disposal.

In summation, the large industrial users seemed to feel that the recommendation of specific incentives aimed at commercialization and resource development was premature at this time because of the immature state of the geopressured-geothermal program. They expressed approval of the measures which the government has taken and is planning, but felt that it was too early in the program for large industrial users to play a major role.

GAS PIPELINE AND DISTRIBUTION COMPANIES

The primary interest of these participants also was in the methane contained in the geopressured-geothermal resource. Participation was keen in this meeting, resulting in an extensive list of recommendations.

As participants in the previous two meetings had done, the pipeline company representatives favored continued research and development funding by the federal government. They suggested that the research orientation should be toward finding solutions for problems which are unique to geopressured-geothermal reservoirs. This group expressed their concern for the environmental questions of subsidence, aquifer contamination, and water disposal. In addition, they proposed the creation of a position of ombudsman for environmental concerns.

Within the general topic of policy reform, the gas company participants made several major points. First, they stated that extensions to the time limits on any current incentives (e.g., tax credits) from their current expiration dates was imperative if their companies were to take advantage of the programs. Next the pipeline company representatives dealt with the questions of ownership and dedication. High on their list of issues was the need for resource ownership clarification. At present, the geopressured-geothermal resource is not defined as clearly as they would like and, thus, the ownership of the resource is also unclear in their opinion. They also felt that it is important to eliminate federal override in certification of producing wells. The issue here seems to be the companies' desires to have a single and final authority on the question of well certification. Finally, it was proposed that certification as "new" wells be given to re-entry wells presently capped, and that conversion of presently producing wells to geothermal wells be authorized as they water out. It was also suggested that both types of wells also should be allowed a reconsideration of dedication.

It was, however, the subject of proposed economic incentives that received the most interest. Tax incentives of any kind were the most favored. In addition, they emphasized the importance of preventive measures to keep any tax advantage received by their companies from being passed through to their rate payers. A production tax credit of 50¢/mcf was favored, provided it was not to be limited in time. Acceleration of depreciation on equipment to 5 years was another preferred tax measure.

The next favored economic inducements were the price incentives, although the type and magnitude of these incentives was never specified. Rolled-in pricing versus incremental pricing was also discussed, and the overwhelming conclusion reached was that rolled-in pricing for geopressured-geothermal methane was superior as a development incentive.

Economic inducements through loan guaranties were discussed and the opinion was that these guaranties should be site specific. That is to say that the guarantee should be tailored to meet the needs of a particular project rather than designing a loan guaranty program that may or may not fit the requirements of a company. To the gas company representatives, flexibility in a loan guaranty program was crucial.

Insurance was also thoroughly discussed. Two types of insurance interested the participants: reservoir insurance and subsidence-indemnity insurance. Reservoir insurance protects a company from severe financial loss due to unforeseen reservoir failure. Subsidence-indemnity insurance has already been covered; the conferees emphasized that the premiums for these insurance policies should be reasonable.

Participation in this meeting was full and at times most lively. A concluding recommendation was most enlightening. It was suggested and agreed upon by all that the only people capable of commercial development of the geopressured-geothermal resource were the energy producers and, therefore, incentives programs should be tailored to meet their needs and objectives.

PRODUCERS AND FINANCIERS

Producer and financial representatives were generally not encouraged about the commercial prospect of geopressured-geothermal in the near future, but were not as pessimistic about the viability of the resource as the large industrial users had been. Nevertheless, the participants felt that at the present time there was not enough stimulus available to attract any producer involvement.

Like the other groups, they suggested areas where more research and development efforts were imperative. Research areas such as heat and hot water application, the problems and nature of subsidence, aquifer contamination, and the geophysical characteristics of geopressured-geothermal resources were commonly mentioned in this, as in the other, meetings. This group did recommend that a reasonable number of pilot plants and demonstration projects be devised in conjunction with research well completions. They felt that there was a definite technological lag that must be remedied prior to successful geothermal commercialization.

The participants were quick to point out that the proposed omnibus bill was an excellent attempt to spur activity, but that it should be used in conjunction with a vigorous well drilling program supported by the federal government. Means to accomplish this end included recommendation for larger tax breaks to drillers rather than direct government investment. Direct loans to companies were also felt to be more useful incentives than loan guarantees. The representatives suggested an answer similar to the "Alberta Solution" used in Canada, where the key concepts were a series of tax credits and direct loans to stimulate drilling and production. In short, their responses pinpointed the need for creating an encouraging environment for drillers and producers.

Other topics which had arisen at the previous meetings re-emerged. Producers and financiers agreed, for example, that current incentive programs should be extended beyond current expiration dates.

A particular opinion of this group was that conventional means of risk alleviation which adjust the rates of return a producer receives for participating in a venture would not be effective in the case of a geopressured-geothermal development, because too many variables remain unknown. It was explained that until the natures and magnitudes of the risks involved become more certain, no group of companies was going to venture into the commercialization of geopressured-geothermal without substantial federal support.

In summary, the petroleum production and financial representatives emphasized the need for more research and development programs, and for much more drilling under the direction of the federal government. It would be only after more information was gained that any of the group would venture into geopressured-geothermal commercial development.

CONCLUSION

Although each meeting varied somewhat from the others, common threads were evident throughout. Because of the early stage of the enterprise, every group agreed that time extensions were imperative for current geothermal tax incentives due to expire in 1982. All participants viewed geothermal as an industry in its initial stages, still requiring considerable research and development before becoming economically feasible. The groups were, however, optimistic about geothermal's future, given possible attractive characteristics of the resource, provided the government continued its research and development programs and policies. Finally, all groups expressed a "wait and see" attitude regarding the geopressured-geothermal resource, feeling that it was both proper and necessary for the federal government to bear the primary risks of the program at this stage of development.

PARTICIPANT LIST

Large Industrial Energy Consumers

Mr. K.A. (Al) Prince
Texas Division-Dow Chemical

Mr. Raj Natarajan
Texas Eastern Transmission Corp.

Mr. A.E. (Al) Schlemmer
Texas Eastern Transmission Corp.

Mr. James E. Troyan
Olin Corporation

Dr. Bruce Melaas
Celanese Corporation

Dr. Grey Verner
Occidental Petroleum Company

Mr. Hugh Irvine
Exxon Chemical, USA

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Gilbert Associates, Inc.

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Energy Production Companies and
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Dr. John P. Townley
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Mr. W. James Murdaugh
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Mr. Don Taylor
Ocean Industries Magazine

Mr. Mickey Braden
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Mr. Dave Wheeler
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Mr. William S. Robson
South Texas Electric Cooperative, Inc.

Mr. Lewis A. Wilson
Middle South Services, Inc.

Mr. P.J. (Pete) Karnoski
Brown & Root, Inc.

Mr. Bruce Byington
Brown & Root, Inc.

Mr. Herb Woods
Gilbert Associates, Inc.

APPENDIX C

FOOD AND KINDRED PRODUCTS (SIC GROUP 20)

Most products or processes within the food and kindred products group are low in energy intensiveness. Many of the production and processing steps done in this group are within the temperature range up to 350°F. Table 1 identifies appropriate sub-categories of industries within the SIC group 20 and temperature ranges utilized for various production stages.

The food and kindred products industries are rigidly regulated by government agencies to assure the quality of the product and sanitation. Cleanliness and sanitation are primary requirements, and because of its cleanliness and flexibility, natural gas has become a major source of energy for process heat requirements. Refrigeration is done by either electrically-driven refrigeration equipment or gas-driven absorption refrigeration equipment.

Overall, the industry has shown a steady decrease in the amount of energy used per unit of production since the 1950's because of technological advances in process equipment. However, increased demand and production has resulted in continued growth in the industry's requirements for energy; Table 2 shows energy consumption and product value data projected to 1980.

Below is a brief description of some of the SIC group 20 processes and the temperature range required in each. Firms using these processes are located along the Texas Gulf Coast and were contacted for the market survey discussed in Chapter VIII.

(2011) Meat packing, (2013) sausages and prepared meats, and (2016) poultry dressing are done in establishments that slaughter for public commercial consumption cattle, hogs, sheep, lambs, calves, horses, and other animals (poultry), except small game. This meat may be sold or used on the same premises in canning and curing, and in making sausage, lard and other products. Table 1 lists the basic steps involved in processing meat products.

In the past, equipment has been the major cost item in this industry. Per capita consumption of meat continues to rise, especially beef and, aside from short-term fluctuations, this condition should continue, thus requiring increased fuel and energy. Increasing prices for fuel, especially natural gas, could in the future have significant impact on these industries. The principal use of gas is for boiler fuel. Steam is used in the plants for rendering and other meat processing. Hot water from the steam cycles is utilized throughout the plants for washing animal carcasses and for the constant cleaning process.

(2022) Natural cheese, (2023) condensed and evaporated milk, (2024) fluid milk, and (2026) ice cream, make up the general category of milk and related products. The firms of this group are primarily engaged in processing (pasteurizing, homogenizing, vitaminizing, bottling) and distributing fluid milk, cream, and related products. The basic processing steps of the products are listed in Table 1. Major pieces of equipment in the industry, such as hot water boilers, reciprocating engines and turbines, water pumps, clarifiers, pasteurizers and compressors, are uniform throughout the United States. Natural gas is the predominant source of energy for processing equipment, while all others are usually operated with electricity.

(2033) Canned fruits and vegetables and (2034) dehydrated fruits and vegetables include establishments that process and package fruits, vegetables, and their juices; catsup and other tomato sauces; and jams, jellies, and preserves.

The production of canned foods involves cooking food and sterilizing the can as well as the food, either at the same time or in two separate processes. In general, less energy and time is required when food is cooked and sterilized without the can surrounding it. Recent advances in food cooker technology now allow the product to be cooked at higher temperatures (approximately 275°F) for shorter periods of time. The consequences are that the quality of the food is higher and less energy is consumed per unit of output.

Dehydration processes are much like those of canned food in the first stages. However, fruits and vegetables to be dehydrated are sent to dryer vats between the cooking and packaging steps of the processing.

Natural gas and electricity are utilized more than any other sources of energy. Increased electricity usage in this product area will correspond directly to the increased automation of processes that has been predicted.

(2037) Frozen fruits and vegetables category includes all frozen foods other than seafood. Common products of this group are frozen juices (citrus and other), dinners, fruits, vegetables, pies, pizzas, spaghetti with meatballs, and waffles.

Unlike the standard procedures used in food canning, production processes in the frozen foods group are varied. Over the past two decades the frozen food industry has grown substantially. Producers have been continually motivated to improve the quality of their product. Frozen vegetables and fruits occupy about one quarter of the total production, while juices represent about 20% of the total, and frozen specialties represent the rest. Demand for energy depends upon the method of freezing and the volume of the product; since production methods are so varied, demand for energy fluctuates.

The trend has been away from the "sharp-freezing" method, which involves the lowering of the room-temperature to freeze the product, and toward the "quick-freezing" method in which the product is frozen in only a few minutes.

Many variations exist for the method of quick-freezing. Each establishment has determined which method is most suited to its plant and product and the standards that must be met. Techniques commonly used today include direct immersion (product dipped in refrigerant), indirect immersion (metal conductor added), plate freezing (refrigerant passes through layers of metal plates), and double-belt freezing, in which foods are sprayed as they pass a given point. One of the more recent innovations, cryogenic freezing with liquid nitrogen or other low temperature refrigerants, has become popular. However, the high cost of nitrogen prohibits widespread adoption of this method. Overall, the trend toward quick-freezing has resulted in increased demands for energy to operate required equipment.

(2048) Prepared feeds includes establishments engaged in manufacturing prepared feeds for animals and fowls. The animal feed industry has become one of the largest industries serving agriculture. The increased demand for meat, poultry, eggs, and dairy products has directly affected the growth of this group. The standard procedures for feed manufacturing include:

1. Mixing - mixing operations are carried out in three stages: a) mixing of high percentage ingredients and selected liquids b) mixing of trace or low percentage ingredients and 3) final blending of remaining liquid before bagging. This process may be carried out by a master electronic control panel which has been programed with the feed-mix formulation.

2. Grinding - grains are sent to a hammermill for bulk grinding. From here the grains may be sent either to bulk storage bins or a pellet mill.

3. Pelletizing - feed mixture is shaped to form a uniform pellet before being sent to bagging.

4. Bagging.

Energy usage within this group has been directly affected by the increased variety of feeds; the shaping standardization of feed shapes (pelletization); change in product mix; and the demand for pet foods. In short, a larger variety of feeds available, more mixing of types of additives, and rapid advances in product improvement (including shaping) have increase energy requirements in the manufacturing processes.

(2051) Bread and related products includes all bakery products other than cookies and crackers. Establishments in this group bake, package, and market perishable baked products. Natural gas is the predominate energy source for baking, and its usage has been made more efficient by heat convection through air agitation.

The bakers in this group may be classified in one of four subgroups listed below:

Wholesale bakers - bakeries selling primarily to other businesses at the whole-sale level, such as grocers, restaurants, and other concerns buying products for resale.

Grocery chain bakeries - bakeries operated by chain stores whose products are distributed only through the chain's retail outlet.

Home service bakeries - bakeries selling their products through retail home service routes.

Retail multi-outlet bakeries - bakeries selling chiefly through non-baking outlets. An example of this would be a restaurant chain which operates its own bakeries.

Bread has always been the primary product. It occupies approximately 65% of the product value of shipments. There are two basic methods used in commercial bread making. The first is known as the "classic method". For this method ingredients are mixed prior to fermentation, with about 60% of the flour already added, and the resulting mix is a sponge-like material. The second method is utilized more by large commercial bakers. It is called a "continuous baking process". For this method a ferment or broth is mixed with a portion of the flour; the amount of flour however is then pumped through various processes prior to baking. The adoption of the agitation air flow method of baking has resulted in substantial decreases in the amount of energy required for baking.

TABLE 1

<u>SIC 20</u>		<u>Food and Kindred Products</u>	Temperature °F
Sub-categories of Products			
2011	Meat Packing		
2013	Sausages and prepared meats		
	scalding, carcass wash, and cleanup		140
	singing flame		500
	edible rendering		200
	smoking/cooking		155
2016	Poultry dressing - scalding		140
2022	Natural cheese		
	pasteurization		170
	starter vat		135
	make vat		105
	finish vat		100
	whey condensing		160-200
	process cheese blending		165
	whey drying		120*
2023	Condensed & Evaporated Milk		
	stabilization		200-212
	evaporation		160
	spray drying		350-400
	sterilization		250
2026	Fluid Milk - Pasteurization		162-170
2032	Canned Specialities		
	precook (blanch)		180-212
	simmer blend		170-212
	sauce heating		190
	processing		250
2033	Canned fruits and vegetables		
	blanching/peeling		180-212
	pasteurization		200
	brine syrup heating		200
	commercial sterilization		212-250
	sauce concentration		212
2034	Dehydrated fruits and vegetables		
	fruit and vegetable drying		165-185
	peeling		212
	precook		160
	cook		212
	flake dryer		350
	granule flash dryers		550

2037	Frozen Fruits and Vegetables	
	citrus juice concentration	190
	juice pasteurization	200
	blanching	180-212
	cooking	170-212
2044	Rice Milling	
	rice parboiling	
	quick rice processing	
2046	Wet corn milling	
	steel water evaporator	350
	starch dryer	120*
	germ dryer	350
	fiber dryer	1000
	gluten dryer	350
	steepwater heater	120
	sugar hydrolysis	270
	sugar evaporator	250
	sugar dryer	120*
2048	Prepared Feeds - Pellet Conditioning	180-190
2051	Bread & Baked Goods	
	proofing	100
	baking	420-460
2062	Cane Sugar Refining	
	mingler	125-165
	melter	185-195
	defecation	160-185
	revivification	750-1110
	granulator	110-130
	evaporator	265
2074	Cotton Seed Processing (extracting oil)	
2077	Animal and Marine Fats - Continuous Rendering of Inedible Fat	330-350
2079	Shortening and Cooking Oils	
	Oil Heater	160-180
	Wash Water	160-180
	Dryer Preheat	200-270
	Cooking Oil Reheat	200
	Hydrogenation Preheat	300
	Vacuum Deodorizer	300-400
2802	Malt Beverages	
	cooker	212
	water heater	180
	mash tub	170
	grain dryer	400*
	brew kettle	212
2086	Soft Drinks	
	bulk container washing	170
	returnable bottle washing	170
	nonreturnable bottle warming	75-85
	can warming	75-85
2092	Shrimp Processing	*

* No special temperature required; requirement is simply to evaporate water or to dry the material.

Source: Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, Intertechnology Corporation, Warrenton, Virginia (1977) V. III p. 41-45.

TABLE 2
FOOD AND KINDRED PRODUCTS VALUE OF SHIPMENT AND
GROSS ENERGY CONSUMED PROJECTIONS TO 1980

	<u>Value of Shipments in 1967 dollars (millions)</u>	<u>Gross Energy Consumed (trillion Btu's)</u>
Meat & Meat Packing	\$22,169	122.4
Milk & Related Products	8,629	60.4
Canned Fruits & Vegetables	4,195	62.6
Frozen Fruits & Vegetables	6,160	105.9
Prepared Feeds	7,692	104.6
Bread & Related Products	6,082	53.3

Source: Energy Consumption in Manufacturing, by The Conference Board (1974)

THE SURVEY

The Gulf Coast geopressured-geothermal questionnaire surveyed 158 establishments listed in SIC group 20- Food and Kindred Products.* For this group the total response rate was 39.9%. Of the many topics covered in the questionnaire, the responses dealing with current and future fuel types for manufacturing purposes and the projected percentages for equipment replacement by 1994 were most interesting.

fuel sources: Responses from SIC group 20 indicated that natural gas as a fuel source comprises 88.7% of current process heat usage. Future projections showed only a slight decrease to 86.8%, thus indicating that Food and Kindred industries will continue to rely heavily on natural gas as a fuel source. Electricity, propane and oil were listed as fuel sources for process heat requirements in respectively 5.7%, 3.8%, and 1.9% of the responses. Future projections indicated a continued utilization at the same rate for electricity and propane, with an increase for oil to 3.8% of the total. The predominant current source of fuel for process chilling was electricity. There was no change indicated for the future.

equipment replacement: Respondents indicated that equipment replacement would be a major activity in the future. By 1994 half of the respondent companies plan to replace 30% or more of their equipment used for process heat. Of the others, 41.3% indicated that they expected to replace a maximum of 10% of their process heat equipment.

The survey participants were also asked whether or not their establishment had significant quantities of low level heat (below 350°F) in plant that currently could not be utilized. Thirty-two percent (32.1%) of the respondents in SIC group 20 replied that this was true in their situation.

*The mailout questionnaire was sent to establishments listed by SIC Code on a computer listing provided by the Bureau of Business Research, The University of Texas at Austin. Establishments with fewer than eight (8) employees were not included in this survey.

Respondents were also asked to rank the factors directly affecting the future investment plans of their establishments. These factors were: cost of equipment; equipment maintenance; fuel cost; environmental factors; equipment safety; public image; reliability of fuel supply; and simplicity of equipment operation. Based on the mean response, the factors rankings (from most to least important), were:

1. reliability of fuel supply
2. fuel cost
3. equipment safety
4. simplicity of operation
5. equipment maintenance
6. equipment cost
7. environmental factors
8. public image

PAPER AND ALLIED PRODUCTS (SIC GROUP 26)

The Paper and Allied Products industry group, SIC 26, is composed of four sectors, Pulp, Paper, Paperboard, and Converting Mills. The industry's primary output is paper and paperboard; pulp may be considered an intermediate product, and converted products a secondary output.

The sub-groups listed under Paper and Allied Products are (2611) pulp mills, (2621) paper mills, and (2631) paperboard mills. Pulp mills primarily manufacture pulp from wood or from other materials such as rags, linters, waste paper, and straw. Paper mills manufacture paper (except building paper - SIC 2661) from wood pulp and other fibers; they may also manufacture converted paper products. Paperboard mills primarily make paperboard and may also manufacture converted paperboard products. Table 3 lists the temperature range requirements for the process steps discussed below.

TABLE 3
SIC 26 PAPER AND ALLIED PRODUCTS

		Temperature °F
2611	Pulp Mills	
2621	Paper Mills	
2631	Paperboard Mills	
	Pulp digestion	370
	Pulp refining	150
	Black Liquor Treatment	280
	Chemicals Recovery-Calcining	1900
	Pulp and paper drying	290

Source: Intertechnology Corporation, op.cit. p. 46

Paper making starts with pulpwood. The basic methods for getting wood pulp may be summarized as follows. The logs are de-barked, with the bark frequently being collected and utilized as fuel. Next, the log is reduced to chips by a mechanical chipper using electric drive. Then the chips are processed into pulp through chemical methods. Presently pulp is produced from wood utilizing several methods. The alkaline sulfate, or Kraft process, accounts for about 70 percent of the pulp production in the United States (Hornburg and Lindal, 1978). Other processes under development or in the pilot stage are the alkaline-oxygen (A-O) pulping process and the Rapson Effluent-Free Kraft process.

In the Kraft process, almost any kind of wood may be used. However, coniferous woods are by far the most utilized. The pulp and paper plant is made up of: 1) a pulping and process unit, 2) a bleach plant, and 3) a paper mill. In a simplified description, a pulp and paper mill feeds fuels including coal, oil, gas, and such by-products as bark, wood waste, and spent liquors, into boilers to generate steam, some or all of which is passed through a turbine to generate electricity. The steam may then be recycled for use in paper drying or pulping.

A typical 1000 ton-per-day bleached paper mill using the Kraft process requires a gross energy input of 1827×10^6 Btu/hr., or 12.8 trillion Btu's per year (Hornburg and Morin, 1975).

In chemical pulping, the chips are mixed with chemicals and then cooked in a digester under controlled pressure, temperature, liquor composition, and time. After the pulp is cooked to remove the lignin components, the mixture undergoes a second state of processing wherein the liquor (chemical solution) containing the lignin compounds is removed, the condition of the cellulose fiber is developed, and the mixture is cleaned and in some cases bleached. Table 4 describes the heat requirements for the Kraft process.

Some paper is produced by mechanical pulping methods. This method utilizes force instead of heat to obtain the necessary fiber state, either by grinding or explosive decompression (defibrating). Mechanical pulping wastes less raw material and potentially produces fewer effluent solids than the chemical processes. However, chemical pulping produces a better grade of paper and is less energy intensive.

The produced pulp is dried in most cases by steam and then transferred to the paper mill, or paperboard mill. Machinery to produce paper or paperboard is similar in basic operation. Energy requirements are based on the thickness of the product; the thicker the product, the greater the energy required for drying. In most cases, super-heated steam is used in drying paper. However, radiant heating elements fueled by natural gas are not uncommon.

TABLE 4
THE HEAT REQUIREMENTS FOR THE STANDARD KRAFT PROCESSES

Use	Steam - pounds/hr.	
	25 psiA	135 psiA
Wash water heating	247,654	-0-
Evaporators	114,594	-0-
Miscellaneous, L.P.	2,952	-0-
Black liquor heating	-0-	5,630
Digester	-0-	160,737
Dryer	-0-	330,016
Miscellaneous, H.P.	-0-	69,980
TOTALS	365,200	570,370

Source: Hornburg and Lindal, 1978 p. 9.

In the state of Texas there are nine pulp and paper mills, of which four are co-located with a geothermal fairway (U.S. Gypsum Co., Galena Park; Southland Paper Mills, Houston; Owens-Illinois, Inc., Orange, Champion International, Pasadena).

THE SURVEY

The Gulf Coast geopressured-geothermal questionnaire surveyed 17 establishments listed in SIC group 26- Paper and Allied Products. For this group the total response rate was 47.1%. Of the many topics covered in the questionnaire, the responses dealing with current and future fuel types for manufacturing purposes, and the projected percentages for equipment replacement by 1994 are most relevant to this discussion.

fuel sources: Responses from SIC group 26 indicated that natural gas as a fuel source comprises 66.7% of current process heat usage. Future projections showed a decrease to 50% in reliance on natural gas, still indicating continued dependence on gas as a major fuel source. Electricity and "other" were also listed as major fuel sources, each with a 16.7% share of the market. Future projections indicated that in addition to the fuels mentioned above, coal would also be utilized for manufacturing purposes. The percentage decrease in reliance on natural gas emerges in the future as a switch to coal. Process chilling is not a major operation in SIC group 26, but of those who responded to the question the predominant fuel source indicated was electricity.

equipment replacement: Respondents indicated that equipment replacement would not be a major activity in the future. By 1994, only 40% of the respondent companies plan to replace 30% or more of their equipment used for process heat. The other 60% of the respondents indicate they will replace only 10% of their process heat equipment.

The survey participants were also asked whether or not their establishment had significant quantities of low level heat (below 350°F) in plant that currently could not be utilized. Only 16.7% of the respondents in SIC group 26 replied that this was true in their situation.

Respondents were also asked to rank the factors directly affecting the future investment plans of their establishments. These factors were: cost of equipment, equipment maintenance, fuel cost, environmental factors, equipment safety, public image, reliability of fuel supply, and simplicity of equipment operation. Based on the mean responses the factors were ranked in the following order, from most to least important:

1. equipment safety
2. fuel supply/equipment maintenance
3. equipment cost
4. simplicity of equipment operation
5. fuel cost
6. environment
7. public image

CHEMICALS AND ALLIED PRODUCTS (SIC GROUP 28)

The SIC group 28 is a large and all-encompassing grouping of the chemical industry, including both organic and inorganic chemicals and their allied products. Because of the size of this group, it would be impossible to characterize all of the processes involved in chemical production. Instead, a few major industrial groups will be detailed which were also included in the geopressured-geothermal market survey found in Chapter VIII of this report. Process and temperature ranges are listed in Table 5.

TABLE 5
Chemicals and Allied Products

		Temperature °F
2819	Alumina	
	Digesting, Drying, Heating	280
	Calcining	2200
2821	Plastic Materials and Resins	
	Polystyrene, suspension process	
	Polymerizes Preheat	220-215
	Heating Wash Water	190-200
	Drying	200
2822	Synthetic Rubber	
	Cold SBR Latex Crumb	
	Bulk Storage	80-100
	Emulsification	80-100
	Blowdown Vessels	130-145
	Monomer Recovery by Flashing & Stripping	120-140
	Dryer Air Temperature	150-200
	Cold SBR, Oil-carbon Black Masterbatch	
	Dryer Air temperature	150-200
	Oil Emulsion Holding Tank	80-100
	Cold SBR, Oil Masterbatch	
	Dryer Air temperature	150-200
	Oil Emulsion Holding Tank	80-100
2823	Cellulosic Man-made Fibers	
	Polyester	500
	Nylon	535
	Acrylic	250
	Polypropylene	540
2824	Noncellulosic Fibers	
	Rayon	212
	Acetate	212
2834	Pharmaceutical Preparations	
	Autoclaving & cleanup	250
	Tablet & Dry-capsule Drying	250
	Wet Capsule formation	150
2841	Soaps and Detergents	
	Soaps:	
	Various processes in Soap Manufacture	180
	High temperature processes	490
	Spray Drying	500*
	Detergents:	
	Various low-temperature processes	180
	High-temperature Processes	500
	Drum-dried Detergents	350*
	Spray-dried Detergents	500*

*No special temperature required.

Source: Intertechnology Corporation (1977) op. cit.

Group 2818, Industrial Organic Chemicals, are frequently referred to as petrochemicals. The majority of these chemicals are inputs to other products, although some are utilized as end products. Final products such as plastics, synthetic fibers and rubber, fertilizers, pesticides, detergents, solvents, and gasoline additives are partially composed of petrochemicals from this group. Most of these chemicals are compounds of carbon, with one or more of hydrogen, oxygen, nitrogen, sulfur, chlorine, fluorine, or lead added.

The petrochemical industries have historically had rapid technological progress and increased economies of scale. Their products have remained in an excellent competitive position within a broad base of consumer and industrial uses. This group is a large user of energy, mainly natural gas, for thermal processing and electric generation as well as feedstocks. Future energy utilization rates will be affected by two major factors: (1) energy price increases, and (2) process improvements.

Industrial Inorganic Chemicals (2819), not elsewhere classified, includes inorganic salts of sodium (excluding refined sodium chloride), potassium, aluminum, calcium, chromium, magnesium, mercury, nickel, silver, tin; inorganic compounds such as alums, calcium carbide, hydrogen peroxide, phosphates, sodium silicate, ammonia compounds and anhydrous ammonia; rare earth metal salts and elemental bromine, fluorine, iodine, phosphorous, and alkali metals (sodium, potassium, lithium, etc.). In all there are over 200 chemicals allocated to this group. Generally the inorganic chemicals group may be characterized by rapid technological innovation which did much to reduce the amount of energy most chemical processes required, and by significant growth in both the uranium diffusion production and the production of synthetic anhydrous ammonia, primarily for fertilizer. The result has been that while the majority of inorganic chemical processes were becoming more energy efficient, two significant components were growing at such a rapid rate that they have virtually cancelled any industry-wide savings of energy.

Plastic Materials (2821), Synthetic Resins, and Nonvulcanizable Rubber (elastomers) are manufactured using phenolic and other tar acid resins, urea and melamine resins, polyethylene and polypropylene resins, styrene resins, and vinyl resins. Plastics and resin materials are typically produced from intermediate organic chemicals such as styrene and phenol. Basically, plastics are synthetic organic chemicals built from a hydrocarbon base. The hydrocarbons used as an energy source are also major feedstock input. Thus, any petroleum shortage or change in supply would affect this industry greatly.

Below is a description of the production processes used in plastic, published in Energy Consumption in Manufacturing, 1974:

"Production Processes

The chemical conversion for resin manufacture is polymerization, where single molecules react to form polymers. The two principal types of polymerization are condensation and addition. In addition polymerization when the monomer units polymerize, they do not completely break a chemical bond, but form a new bond between monomers. The result is a polymer which has an identical structural unit with the monomers from which it is formed. In condensation polymerization, the chemical bonds between atoms completely rupture; polymers formed by condensation reactions have structural units lacking certain atoms present in the monomers from which they are formed.

Polymerization can take place in a number of ways such as bulk, solution, emulsion, or suspension. Products of condensation polymerization include phenolic resins, amino resins, and polyester resins. Products of addition polymerization encompass polyolefins (which include polyethylene and polypropylene), vinyl resins, vinyl alcohol resins, vinylidene chloride resins, styrene resins, and acrylic resins."

Synthetic Rubber (2822), is a group of manufactures which produces synthetic rubber by polymerization or copolymerization. The materials used in this production are called elastomer (rubber-like) materials, such as, butadienes, acrylonitriles, styrenes, chloroprenes and isobutylene-isoprenes. Styrene-butadiene rubber (SBR) makes up the majority of synthetic rubber manufacturing. It is used mostly in the making of automobile tires.

The manufacturing processes of synthetic rubber require great amounts of steam. Natural gas is the predominant source of energy for making steam. Most of the power machinery used requires electricity for operation.

THE SURVEY

The Gulf Coast geopressured-geothermal questionnaire surveyed 104 establishments listed in SIC group 28, Chemicals and Allied Products. For this group the total response rate was 56.7%. Of the many topics covered in the questionnaire, the responses dealing with current and future fuel types for manufacturing purposes, and the projected percentage for equipment replacement by 1994 were significant.

fuel sources: Responses from SIC group 28 indicated that natural gas as a fuel source comprises 77.6% of current process heat usage. Future projections showed a decrease to 62.0% in reliance on natural gas, still indicating continued dependence on natural gas as a major fuel source. Also listed as major fuel sources were oil, purchased steam, and "other," respectively with 6.1%, 2.0%, and 14.3% of the market. Future projections indicated that oil would rise to 16.0% of the market while purchased steam remained at 2.0%, and "other" fell to 12.0%. The remaining share of the fuel market would be covered in the future by coal and electricity each with a 4.0% share. Current fuel resources for process chilling were listed predominately as electricity (63.2%) and gas (21.1%). Responses on the future prospects indicate that gas usage will fall to 15.4% while electricity usage for process chilling will rise to 66.7% of total.

equipment replacement: SIC group 28 respondents replied that equipment replacement and/or installation of additional equipment for process heating would be a major activity in the future. Fifty-four percent (54.5%) responded that by 1994 they would replace 30% or more of their present plant.

The survey participants were also asked whether or not their establishment had significant quantities of low level heat (below 350°F) in plant that currently could not be utilized. Over forty percent (41.8%) of the respondents in SIC group 28 replied that this was true in their situation.

Respondents were also asked to rank the factors directly affecting the future investment plans of their establishments. These factors were: cost of equipment; equipment maintenance; fuel cost; environmental factors; equipment safety; public image; reliability of fuel supply; and simplicity of equipment operation. Based on the mean response, the factors were ranked in order of importance as follows:

1. equipment safety
2. fuel supply
3. fuel cost
4. environmental factors
5. equipment cost
6. equipment maintenance
7. public image
8. simplicity of equipment operation

PETROLEUM REFINING (SIC GROUP 29)

Petroleum refining is a large, mature industry with well defined markets. Along the Texas Gulf Coast it is by far the largest industrial user of energy for both thermal processes and feedstocks. Overall, the energy consumption of a refinery is dependent on its complexity and age. Older refineries designed when fuel was less expensive usually consume more fuel. However, the average fuel consumption in the US petroleum refining industry has remained nearly constant at about 2.6×10^6 Btu's per ton of refined product. At the same time, over the past twenty years, total refinery production has increased; the reason is that petroleum refining is a heterogeneous industry with wide varieties in feedstock, product mix and process methods. Certain processes are similar, but it can be said that no two refineries are exactly alike.

In general, crude oil, either domestic or imported, and natural gas liquids from natural gas plants are taken and transformed into a variety of fuels needed for various engines, motors, and heaters. Other non-fuel products may also be manufactured such as, chemical feedstocks, roofing and road surfaces, and lubricants. However, the dominant product is gasoline, with distillate fuel oil (home heating), diesel fuel, and jet fuel following.

Notes: *Process capacity indices (with crude topping = 100)
applicable to all complete processing refineries.
†Including naphthenic lubes and specialties processes.

Petroleum Refining Processes. Source: "Estimating Production and Repair Effort in Blast-damaged Petroleum Refineries" by Frank E. Walker, July, 1969

Figure 1: BASIC PETROLEUM REFINING PROCESSES?

Net energy usage within a refinery may be broken down as follows:**

<u>Type</u>	<u>Percent of total net</u>
Direct firing	60
Process steam	26
Steam for mechanical drives	8
Electricity	<u>6</u>
Total	100

Source: Hornburg and Lindal. op. cit.

The average process steam pressure, exclusive of steam used for mechanical drives, is less than 200 psi, and most of the low-level heat is used in petroleum refineries for vacuum distillation, lube oil refining and gas refining. The temperature range for these processes is between 250°F-350°F. Table 6 lists temperature ranges for other petroleum processes.

Figure 1 is a reproduction of basic petroleum refining processes from Frank E. Walker, "Estimating Production and Repair Effort in Blast-damaged Petroleum Refineries," July 1969. Below is a summary of the processes represented in the table (Energy Consumption in Manufacturing, 1974).

Refineries may be classified as simple, complex, or fully integrated depending on the processes they perform. In nearly all of the processing units shown in the flow sheet, energy is required in the form of direct heat to raise the temperature of the oil being processed. Additional energy is required for mechanical drives to force the oil through the process.

Essentially all crude oil is subjected first to a distillation at near-atmospheric pressure known as topping or crude distillation. The straight-run products of topping with the lowest boiling point, known as light naphthas, usually go directly into gasoline. The other straight-run products (kerosene, diesel fuel or light distillate) are usually desulfurized or treated with hydrogen, and the heavy (gasoline) naphtha must be catalytically reformed to improve its octane number. The highest boiling straight-run product, gas oil, constitutes the feedstock to catalytic cracking, or hydrocracking. Through the cracking process (decomposition of hydrocarbon materials at high temperatures) the yield of gasoline from heavier materials is further increased.

The residue or topped crude oil is further reduced or processed in five main ways: (1) viscosity breaking, coking, or vacuum distillation, which is followed by (2) catalytic cracking, (3) hydrocracking, (4) lubricating oil manufacture, and (5) asphalt manufactures. Amounts of residue may also be directly hydrocracked for the production of low-sulfur residual fuel oil. Olefinic gases are assembled from all decomposition processes for polymerization, or more often alkylation, into the boiling range of gasoline. In the case of alkylation, the isobutane is also assembled from catalytic hydrocracking and catalytic refining.

THE SURVEY

The Gulf Coast geopressured-geothermal questionnaire surveyed 48 establishments listed in SIC group 29- Petroleum Refining. For this group the total response rate was 56.3%. Of the many topics covered in the questionnaire the responses dealing with current and future fuel types for manufacturing purposes, and projected percentages for equipment replacement by 1994 were significant.

fuel sources: Responses from SIC group 29 indicated that natural gas as a fuel source comprises 87.0% of current process heat usage. Future projections showed a decrease to 65.2%, indicating continued dependence on gas as a major fuel source.

TABLE 6

PETROLEUM REFINING TEMPERATURE REQUIREMENTS FOR PROCESSING

	Temperature °F
2911 Petroleum Refining, Crude Distillation	
Atmospheric topping	650
Vacuum distillation	440-800
Thermal operations	555-1010
Catalytic cracking	1125
Delayed coking	900
Hydrocracking	515-810
Catalytic reforming	925
Catalytic hydrotreating	700
Hydrotreating	700
Alkylation	45-340
Hydrogen plant	1600
Olefins and Aromatics	1200
Lubricants	unavailable
Asphalt	unavailable
Butadiene	250-350
2951 Paving Mixtures	
Aggregate Drying	275-325*
Heating Asphalt	325
2952 Asphalt Felts & Coatings	
Saturator	400-500
Asphalt Coating	300-400
Drying (Steam)	350
Sealant	300-400

*No special temperature required

Source: Intertechnology corporation (1977) op. cit.

Other fuel source categories mentioned were oil (4.3%) and "other" (8.7%). Responses to future fuel sources disclosed that the decreased usage of natural gas is due to an increase in oil (up to 26.1%). A few of the respondents indicated that they also had fuel requirements for process chilling. This group denoted an equal dependence on electricity and gas for chilling purposes, each holding 41.7% of the market. While future prospects for process chilling fuel indicates that some will switch from gas to oil (8.3%), electricity maintains a constant percentage of total.

equipment replacement: SIC group 29 respondents replied that equipment replacement and/or installation of additional equipment for process heating would be a major activity in the future. Thirty-six percent (36.4%) of the respondents indicate that their establishment would replace 10% of equipment. On the other hand, 45.5% of the respondents replied that they would be replacing 30% or more of their present plant.

The survey participants were also asked whether or not their establishment had significant quantities of low level heat (below 350°F) in plant that currently could not be utilized. Forty-five percent (45.8%) of the respondents indicated that this was true in their situation.

Respondents were also asked to rank the factors directly affecting the future investment plans of their establishments. These factors were: cost of equipment, equipment maintenance, fuel cost, environmental factors, equipment safety, public image, reliability of fuel supply, and simplicity of equipment operation. Based on the mean response the factors were ranked in order of decreasing importance:

1. Fuel Cost	5. Equipment Maintenance
2. Environmental Factors	6. Fuel Supply
3. Equipment Safety	7. Simplicity of Equipment Operation
4. Equipment Cost	8. Public Image

STONE, CLAY, AND GLASS (SIC GROUP 32)

Within the major SIC 32 group (3241) hydraulic cement, (3271) concrete blocks, (3273) ready-mix concrete, and (3275) gypsum covered wallboard are represented along the Gulf Coast.

The hydraulic cement industry includes Portland, natural, masonry, and pozzolan cements. Portland cement manufacturing represents 96% of the output by weight from this sub-group.

Basically, the production of hydraulic cement involves; (1) proportioning a lime-containing substance and a material containing silica, alumina, and iron; (2) grinding these to a slurry or powder; (3) "burning" the mixture in a rotary kiln with gypsum into a fine powder. Substantial energy is used for mechanical processes and to fire the kiln.

Portland cement may be made by either a "dry" or "wet" process, the difference being in the state of the mixture during and after the blending procedure. The dry process consumes less energy per unit of production, but has other drawbacks not found in the wet process. Historically, because of the low cost of energy in the US, the wet process has been the dominate method of manufacturing Portland cement.

(3273) Ready-mixed concrete may be described as a sub-group of establishments engaged in the manufacturing of Portland cement concrete and delivering it to their customers in a plastic and unhardened state. This includes the sale of central-mixed, shrink-mixed and truck-mixed concrete.

In general the production processes for the finished products in this industry require very high temperatures, with the bulk of the energy going to direct firing of the kilns. Table 7 gives a list of the processes and their temperature ranges, some of which are comparable to the temperature range found in the geopressured-geothermal resource.

THE SURVEY

The Gulf Coast geopressured-geothermal questionnaire surveyed 45 establishments listed in SIC group 32- Stone, Glass, & Clay Industries (cement). For this group the total response rate was 42.2%. Of the many topics covered in the questionnaire, the responses dealing with current and future fuel types for manufacturing purposes, and the projected percentages for equipment replacement by 1994 were significant.

fuel sources: Responses from SIC group 32 indicated that natural gas as a fuel source comprises 55.6% of current process heat usage. Other sources listed were Coal (11.1%), Butane (11.1%), Electricity (11.1%), and other (11.1%). Future projections indicate no change from current usage pattern.

equipment replacement: SIC group 32 respondents replied that equipment replacement and/or installation of additional equipment for process heating would not be a major activity in the future. By 1994, fifty-seven percent (57.1%) of the respondents indicated plans to replace 10% of equipment used in process heat. On the other hand, forty-three percent (43.9%) indicated plans to replace 30% or more of their present plant.

The survey participants were also asked whether or not their establishment had significant quantities of low level heat (below 350°F) in plant that currently could not be utilized. Only 16.7% of the respondents replied that this was true in their situation.

Respondents were asked to rank the factors directly affecting the future investment plans of their establishments. These factors were: cost of equipment, equipment maintenance, fuel cost, environmental factors, equipment safety, public image, reliability of fuel supply, and simplicity of equipment operation. Based on the mean responses, the factors were ranked in order of descending importance as:

1. Fuel Supply	5. Equipment Cost
2. Equipment Safety	6. Equipment Maintenance
3. Simplicity of Equipment Operation	7. Public Image
4. Fuel Cost	8. Environmental Factors

TABLE 7
STONE, CLAY, AND GLASS PRODUCTS

		Temperature °F
3241	Hydraulic Cement Drying Calcining	275-325* 2300-2700
3271	Concrete Block Low-pressure curing Autoclaving	165* 360
3273	Ready-Mix Concrete Hot water for mixing concrete	120-190
3275	Gypsum Kettle Calcining Wallboard Drying	330 300

*No special temperature required; requirement is simply to evaporate water or to dry the material.

Source: Intertechnology Corporation (1977) op. cit.

TABLE 8

		Temperature °F
Primary metals temperature requirements for processing		
3312	Blast Furnaces and Steel Mills High temperature uses	2700
3321	Ferrous Castings Gray Iron Foundries (73% of heat)	
3322	Malleable Iron Foundries (10% of heat)	
3323	Steel Foundries (17% of heat) Melting in cupola furnaces Mold and Core Preparation Heat Treatment and Finishing Pickling	2700 300-475 900-1800 100-212
3331	Primary Copper Smelting and Fire-refining	2000-2500
3333	Primary Zinc Pyrolytic reduction	2400
3334	Primary Aluminum Prebaking anodes	2000

Source: Intertechnology Corporation (1977) op.cit.

PRIMARY METALS (SIC GROUP 33)

The primary metals group of industries is characterized by the use of high-grade energy, primarily for direct firing and generating electricity. Over the past thirty years energy consumption patterns have changed, relative to other fuels, in that both natural gas and electricity usage have risen dramatically. During the same period, the use of coal in production of steam and for purposes other than coking has declined. Of all industrial groups, the primary metals group is the most energy intensive, requiring extremely high temperatures for processing and large volumes of energy for electrical production. The eight most energy intensive, out of a total of twenty-four industries, are:

SIC Code

3312	Blast furnaces and steel mills
3313	Electrometallurgical products
3321	Gray iron foundries
3323	Steel foundries
3334	Primary Aluminum
3351	Copper rolling and drawing
3357	Non-ferrous wire-drawing, insulating
3391	Iron and steel forgings

Table 8 gives temperature requirements for several of the primary metals groups processes.

The potential is small for geothermal application in primary metals (Hornburg and Morin, 1975; Hornburg and Lindal, 1978). First, the maximum temperature expected from the geopressured-geothermal resource is 350°F, thus precluding its utilization by primary metal processors except perhaps where the resource is used to produce electricity. Second, and more important for current purposes, there are no primary metals production operations currently located in the geothermal market survey area.

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APPENDIX D

PRELIMINARY LIST OF POSSIBLE INCENTIVES

Tax Incentives

1. Deferral (as opposed to avoidance) of a selected percentage of taxes due on profit from defined geothermal activity. Repaid with or without interest.
2. Exemption from taxation of a selected percentage of the profit attributable to specified geothermal activity. (Example: depletion allowance)
3. Accelerated depreciation or amortization on investments in selected geothermal activity.
4. Tax credits for investment in selected geothermal activities.
5. Current deduction of lease bonuses paid for geothermal properties.
6. County ad valorem (property) tax relief for holders of geothermal properties prior to the commencement of production from those properties.
7. Exemption from state sales tax of specified geothermal equipment.
8. Additional deduction allowances for investment in industrial parks based on geothermal fuel.
9. Allow liberal treatment as a currently deductible R and D expenditure of the cost of geothermal exploration or experimentation on methods to utilize geopressured-geothermal energy.
10. Remove intangible drilling cost deductions from the list of items subject to preference tax.
11. Allow geological and geophysical expenses incurred in the course of developing known geopressured-geothermal areas to be deducted currently instead of requiring that they be capitalized and deducted at the time of abandonment, in the case of projects which do not reach the commercial stage, or subjected to cost depletion.
12. Develop tax inducement to encourage joint ventures between independents and major energy companies.
13. Impose a state tax on geopressured-geothermal resources which are held for a specified number of years without commercial development.
14. Provide for an easier means for acquiring advance rulings from the Internal Revenue Service as to which costs may be deducted by limited partners in geopressured-geothermal development ventures.
15. Allow current deduction of IDC's on shallow disposal wells, on which expenses must now be capitalized.
16. Extend period during which tax benefits may be claimed on:
 - a. Alternative energy property tax credit
 - b. Specially defined energy property tax credit
 - c. Geopressured methane equipment tax credit
 - d. Percentage depletion allowance on geopressured methane
17. Clarify availability of "geothermal" tax incentives to geopressured-geothermal developer.
18. Extend specially defined energy property tax credit to new processes and facilities.
19. Allow exemption from the "windfall" profits tax for profits invested in geopressured-geothermal projects.
20. Extend alternative energy property tax credit to utility taxpayers.

Loan Incentives

21. Federal or state subsidies of interest payments incurred on money borrowed for selected geothermal activities.
22. Develop an energy development bank. If this bank is to loan money to projects other than geopressured-geothermal, then a percentage formula must be developed to allocate funds among the various alternate energy forms.
23. State or federal loan guarantees.
24. Direct the Small Business Administration to give preference to loans for geopressured-geothermal projects.
25. Direct the Secretary of Agriculture to grant preference to agricultural projects requesting loans related to geopressured-geothermal utilization.
26. Extend the GLGP beyond its current 1984 expiration date.
27. Provide for loan forgiveness in lieu of loan default under the GLGP.
28. Develop single-agency regulatory schemes at federal, state, and county levels.
29. Provide greater patent rights for inventions developed in the course of a geopressured-geothermal project which is partially federally funded.
30. Clarify the extent to which regulated utilities may include the expenses for risky ventures, such as geopressured-geothermal development, and their rate bases.
31. Provide method by which firms contemplating multi-faceted geopressured-geothermal utilization may secure from the Justice Department an early determination of anti-trust problems.
32. Provide statutory modification of Federal Energy Regulatory Commission rule which prohibits utility company retention of tax benefits which arise from avoided, as opposed to deferred, tax liabilities.
33. Exclude geopressured natural gas from incremental pricing.
34. Exclude geopressured natural gas from "pipeline supply gas" subject to curtailment.
35. Allow utilities to include costs of construction work in progress on geopressured-geothermal projects in their current rate bases.
36. Direct FNMA and GNMA to give preference to the purchase of indebtednesses secured by geopressured-geothermal collateral.
37. Provide state or federal insurance policies against early reservoir depletion.
38. Provide state or federal insurance policies against damages caused by geothermal activities which induce surface subsidence or deformation of subsurface formations. Possibly, place a statutory limit on liability.
39. Provide state or federal reinsurance for insurance policies taken out on geothermal projects.
40. Provide both state and federal laws under which an industrial consumer can secure wheeling orders to move electric power generated at geopressured-geothermal reservoirs to industrial facilities remote from those reservoirs.
41. Grant the power of eminent domain to industrial consumers who wish to build power transmission networks from geothermal fields to industrial facilities.
42. Modify Securities and Exchange Commission public utility holding company regulations to exclude non-utility producers and transporters of electricity.
43. Devise schemes by which geopressured-geothermal lease bonuses owed by small firms or municipal utilities may be deferred until the property begins to produce income.

44. Subject electric transmission lines to limited common carrier restrictions.
45. Develop manpower training programs or college scholarships and internships to prepare students to work in the geothermal fields.
46. Place a ceiling on government spending (as a percentage of gross national product) in an effort to control inflation.
47. Develop a federal policy of stabilized support for alternate energy development. Long-term support is considered very important by industry planners.
48. Provide for a phased system of environmental impact statements so that early exploration and development efforts require less thorough treatment of environmental impact than is currently the case.
49. Clarify state law regarding the applicability to geopressured-geothermal fluids of the doctrine of capture.
50. Provide the Texas Railroad Commission with authority to regulate production from vertically discrete but overlapping geopressured-geothermal reservoirs.
51. Provide TRC authority for compulsory unitization of geopressured-geothermal reservoirs.
52. Allow long-term interstate common carriage of user-developed and owned geopressured methane for (a) feedstock and (b) boiler fuel use.
53. Allow eminent domain authority for industrially owned geopressured methane transportation facilities.

Grants and Procurement Guarantees

54. Direct state or federal grant for demonstration projects.
55. State or federal guarantees or procurement at a fixed price at some time in the future for geopressured methane, electricity production from geopressured-geothermal reservoirs, or geopressured brine.
56. Guaranteed state or federal procurement of the above elements at some date in the future at cost plus a fixed profit.
57. Government-Industry joint venture demonstration projects.
58. Government subsidy of lease bonuses paid by small or independent geothermal development firms.
59. State or federal direct grants for limited-scope pilot projects.
60. State or federal development grants which provide industry with the option to buy project equity (the grant amount) at some point down the line.
61. Direct state or federal grant to utilities, energy companies, or some other specified class for geopressured-geothermal exploration activities.

Miscellaneous Incentives

62. Develop a more effective information system for those interested in geopressured-geothermal development.
63. Attempt to determine where material or labor shortages might occur during geothermal development and act to prevent those shortages.
64. Develop a reliable way of estimating reservoir life and flow capabilities.
65. Forecast and attempt to prevent labor-management conflict in geopressured-geothermal development.

66. Develop a method for allocating wellhead production values among the various components of a geopressured-geothermal reservoir.
67. Fund a "test case" to secure court determination on resource ownership issue.
68. Focus R and D efforts on in situ geopressured methane extraction technologies.

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GLOSSARY

AEC	-	Atomic Energy Commission
AFUDC	-	Allowance for Funds Used During Construction
AGA	-	American Gas Association
BEG	-	Bureau of Economic Geology
CES	-	The Center for Energy Studies
CWIP	-	Construction Work in Progress
DGE	-	Division of Geothermal Energy
DOE	-	Department of Energy
DWR	-	Department of Water Resources
EPA	-	Environmental Protection Agency
EPRI	-	Electric Power Research Institute
ERA	-	Economic Regulatory Administration
ERCOT	-	Electric Reliability Council of Texas
ERDA	-	Energy Research and Development Administration
FERC	-	Federal Energy Regulatory Commission
FPC	-	Federal Power Commission
FUA	-	Power Plant and Industrial Fuel Use Act of 1978
GCO	-	General Crude Oil, Inc.
GLGP	-	Geothermal Loan Guaranty Program
GLO	-	General Land Office
GRI	-	Gas Research Institute
GURC	-	Gulf Universities Research Consortium
ICC	-	Interstate Commerce Commission
IDC	-	Intangible Drilling Cost
IGT	-	Institute of Gas Technology
IOCC	-	Interstate Oil Compact Commission
IRC	-	Internal Revenue Code of 1954
IRS	-	Internal Revenue Service
ITP	-	Item of Tax Preference
LLL	-	Lawrence Livermore Laboratories
LSU	-	Louisiana State University
Mcf, mcf	-	Thousand cubic feet
NEP 1	-	National Energy Plan 1
NGA	-	Natural Gas Act of 1938
NGPA	-	Natural Gas Policy Act of 1978
NOAA	-	National Oceanic and Atmospheric Administration
NPC	-	National Petroleum Council
NPDES	-	National Pollutant Discharge Elimination System
NSF	-	National Science Foundation
OCS	-	Off-shore Continental Shelf
OPEC	-	Organization of Petroleum Exporting Countries
PUC	-	Public Utility Commission
PURPA	-	Public Utilities Regulatory Policy Act of 1978
RCRA	-	Resource Conservation and Recovery Act
SDWA	-	Safe Drinking Water Act
SIC	-	Standard Industrial Classification
SMSA	-	Standard Metropolitan Statistical Area
SWRI	-	Southwest Research Institute
TACB	-	Texas Air Control Board
Tcf, tcf	-	Trillion cubic feet
TEAC	-	Texas Energy Advisory Council
TIS	-	Texas Interconnected System
TMPA	-	Texas Municipal Power Agency
TRC	-	Texas Railroad Commission
USGS	-	US Geological Survey
USL	-	University of Southern Louisiana
UT	-	University of Texas at Austin