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CRITERIA FOR THE DEVELOPMENT AND USE OF THE
METHODOLOGY FOR ENVIRONMENTALLY-ACCEPTABLE FOSSIL
ENERGY SITE EVALUATION AND SELECTION

Volume 2

Final Report on the Development of Environmental Guidelines for the
Selection of Sites for Fossil Energy Conversion Facilities

February 1, 1980

Work Performed Under Contract Number EY-77-C-02-4574

Cameron Engineers, Inc.
Denver, Colorado
and
Center for the Environment and Man
Hartford, Connecticut

FOSSIL ENERGY

U. S. DEPARTMENT OF ENERGY

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**Prepared for the
Pittsburgh Energy Research Center
U.S. Department of Energy
Under Contract DOE-EY-77-C-02-4574**

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FOREWORD

This is a companion document to the report, "Volume 1: Environmentally-Acceptable Fossil Energy Site Evaluation and Selection: Methodology and User's Guide," in which a methodology for the siting of fossil fuel conversion facilities in areas with minimal environmental impact is discussed. This report, "Volume 2: Criteria for the Development and Use of the Methodology for Environmentally-Acceptable Fossil Energy Site Evaluation and Selection," presents the technical background material necessary for the development and use of the methodology.

These reports were prepared through the joint efforts of Cameron Engineers, Inc., Denver, Colorado, and The Center for the Environment and Man (CEM), Hartford, Connecticut. Both Cameron Engineers and CEM worked under the direction and assistance of Dr. Ralph L. Scott of the U.S. Department of Energy, Pittsburgh Energy Research Center. Dr. Scott, project manager, devoted approximately 1-1/2 years of work prior to the initiation of this contract study, preparing the conceptual and detailed working framework for the study. These two volumes culminate and integrate the efforts of eight months of work by both contractors.

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CHAPTER 1

HIGHLIGHTS

Most Americans who read this report are probably aware that an energy crisis exists, and that the nation is engaged in an important search for new sources of power. Nuclear, solar, wind, and possibilities more exotic are being considered. Work is underway to turn wheat, rubber tires, and even garbage into fuel. Coal is in a revival. Burning wood in fireplaces and stoves has taken on significance as something more than a leisurely winter pastime.

Meanwhile, our conventional fuels, oil and natural gas, two of the so-called "fossil fuels" because they were created from the fossilized remains of ancient plants and animals, have become precious, with conservation more important. Lowered thermostats, smaller cars, and home insulation are only a few ways in which the country is showing recognition of fossil fuel limits. Another is a step-up in research, and in a form that will not create problems for industry, commerce, and the homeowner, not to mention the environment.

For example, as domestic supplies of natural gas and oil dwindle, the nation is being forced to seek out alternatives. A significant alternative is coal, and in The National Energy Plan, presented by President Carter on April 29, 1977, an expansion in the Government's coal research and development program is strongly encouraged.

"Coal will meet the greatest portion of increased U.S. energy needs. A comprehensive coal research and development program is a high priority. The program should focus on meeting environmental requirements more effectively and economically, and should seek to expand the substitution of coal for natural gas and petroleum products." (1)

However, a large number of industrial power units cannot be switched to coal because of design considerations, while plants technically capable of making the change have the economic problem of buying storage, unloading, conveying, ash-handling and air-cleaning equipment.

As a result, the nation's energy priorities include programs to develop economically viable processes for converting coal into gas and oil, or synthetic fuels as they are known. More importantly, synthetics can be used in such urgent areas as transportation and home heating.

Also under the synthetic umbrella are oil shale and tar sands. Oil shale is the term applied to fine-grained sedimentary rocks which contain appreciable quantities of a material called kerogen, that can be chemically transformed to yield oil and gas. Tar sands, oil sands and bituminous sands are all commonly used phrases referring to the same bitumen-impregnated sands, bitumen being a flammable substance.

1.1 Projects and Problems

All of the previous technologies have environmental (physical) and socioeconomic impacts associated with them. For example, the Western Gasification Company (WESCO), has proposed to construct and operate four coal gasification plants on the Navajo Indian Reservation 17 miles southwest of Farmington, New Mexico. According to the final environmental impact statement released by the Department of the Interior, the proposed project would emit 3,262 tons of sulfur dioxide, 6,190 tons of nitrogen oxides and 290 tons of particulates each year. These emissions would adversely affect ambient air quality and visibility. Groundwater quality could be affected slightly over the long term by the disposal of ash and other solid wastes in the mined-out area. The plants and support facilities would occupy 3,840 acres of land. Mining operations would disturb approximately 28,000 acres of land over the 25-year life of the project. The land disturbance would, at least temporarily, destroy wildlife habitat and grazing. If the mine reclamation is not successful, this could be a permanent displacement. Nine to twelve families would be displaced over 25 years. The proposed project would cause a peak influx of 4,025 construction workers and would ultimately employ about 4,000 persons during operation. These workers, their families and the resulting population influx would exert significant pressure on existing social systems and infrastructures. (2)

Similarly, the ANG Coal Gasification Company (ANGCGC) has planned to build a coal gasification plant in Mercer County, North Dakota, in the southwestern part of the state. The complex would produce synthetic natural gas for use in the Michigan and Wisconsin market areas. The water intake, coal and ash handling, and plant access systems would be shared with an adjacent coal-fired power plant proposed by Basin Electric Power Cooperative.

The Department of Interior's environmental impact statement noted that the combined projects would emit 14,665 pounds of sulfur dioxide, 6,143 pounds of nitrogen oxides, and 693 pounds of particulates each hour. These emissions would adversely affect existing ambient air quality and visibility. Surface waters would be temporarily degraded from mining and construction of a 365-mile product gas pipeline which would traverse 86 water areas. Groundwater quantity and quality could be altered by aquifer disturbance and leachates from ash and other solid wastes buried in the mined area. The gasification plant and associated facilities would occupy about 600 acres of land; mining activity would disturb about 12,500 acres over the 25-year life of the plant. Land disturbance would temporarily destroy wildlife habitat and agricultural land and even with successful reclamation the wildlife habitat would be permanently altered. The proposed ANCGC and Basin Electric projects would cause a peak influx of about 6,200 persons during construction and about 4,800 persons during operations into a presently rural area. As with the WESCO project, this population influx would cause significant effects on existing social systems and infrastructures. (3)

In general, the impacts associated with commercial synthetic fuels developments are similar. Plant production and operation requires the construction of roads, mining, plant sites, waste disposal areas, utility and pipeline corridors. Growth in population requires additional services in nearby towns. All of this would permanently alter land use, air and water quality, and the socioeconomic values of an area.

In the development of synthetic fuels facilities, land is disturbed from its present use, primarily because of mining. Of the two types of mining (deep and strip), deep mining disturbs the surface less. Existing vegetation would be destroyed in the mined area, plant sites, housing sites for increased populations, transmission lines, pipeline rights-of-way, roads and railroad rights-of-way.

In many areas, agricultural and forest lands would be removed from their productive uses, and the disturbance of the topsoil by mining and construction would, to some degree, lower the natural soil productivity of the area by compacting and mixing natural soils and by accelerating soil erosion. This disturbance of the topsoil and the accompanying loss of productivity would be unavoidable, and even after many years of reclamation, the highest level of use may only be for pastureland.

After mining, the geology and topography of the reclaimed land would be significantly altered. Construction activities would result in the filling of areas of low relief, the leveling of rolling terrain, the creation of steep slopes where no slopes previously existed, the removal of prominent points of land, the erosion of surface areas and alterations to stream channels and drainage patterns. In addition, construction of impoundments would result in inundation of large areas of land. These effects may alter the geology and topography from the ground surface to the base of the coal, shale or other energy resource.

During operation of the plant, degradation of local air quality would occur. Some damage to plants, animals, and humans from air contaminants may be unavoidable. Adverse human health effects, including cancer, might result from long-term exposure to polycyclic aromatic hydrocarbons and trace elements emitted from synthetic fuel plants in the form of or adsorbed on fine particulates. Some increase in sulfur dioxide, nitrogen oxides, trace elements, hydrocarbons and respirable particulates would occur even though emission controls were used and air quality standards were enforced.

Large volumes of water would be required. In some areas the amount of water allocated to synthetic fuels production would reduce that available for other uses, and could affect agricultural, industrial, commercial and residential uses. Plant production would create a potential for some degradation of local regional water quality. Construction and mining activities would result in increased erosion runoff and sedimentation. In eastern areas of the country acid mine drainage would occur, and in many areas, the lowering of water levels of wells and the interruption of aquifers during mining could not be avoided. In addition, the synthetic fuels plants would produce potential water pollutants including dissolved solids, suspended solids, ammonia, non-degradable organic compounds, oxygenated compounds, mercaptans, and other sulfur compounds, cyanides, phosphates and trace elements.

Loss of wildlife habitat and reductions in population would occur as unavoidable consequences of the mining and utilization of the energy resource. Some mortality and displacement of animals would occur in all regions. These losses would primarily involve birds, small mammals, reptiles and invertebrates; some game species would also be affected. In addition, mining, transportation and processing would expose wildlife to various hazards and disturbances. Blasting, construction, and other noises associated with the mining activity would be unavoidable and would frighten away some wildlife species.

Construction activities could inadvertently disturb or destroy sites of archaeological, historical, paleontological, and aesthetic value. Increased populations would result in increased visitation and vandalism on sites. Visual impacts resulting from construction of rail lines, transmission lines, mine facilities, and industrial plants would also be unavoidable.

Areas which are currently rural would be most affected economically by new development. During the construction phase, "boom town" conditions could create inflation and a shortage of necessary social services, such as health facilities, housing, and schools. Other problems are created by the overburdening of water, sewer, fire and police services. Large population influxes into many of the rural western regions may also create tension between newcomers and existing residents. These latter, socioeconomic effects are exemplified by the concern over oil shale development in northwestern Colorado. The rural quality of life is valued by residents of the area primarily for those aspects which distinguish small rural communities from urban areas. The recreational and aesthetic pleasures of the natural environment are readily accessible to these residents. Also, the small towns provide residents with a sense of personal significance, control and influence over their political and social environment which is difficult to achieve in the rapid pace of an urban setting.

On the other hand, the state of the economy is of primary importance to most residents of the region. Recent opinion studies consistently show that they are desirous of greater economic development, and are aware of the trade-offs involved. (4)

Despite the long list of environmental and socioeconomic hazards, it is clearly possible to manage synfuels development in such a way as to maximize the long term advantages and minimize the disadvantages. Although, as noted, there are certain unavoidable impacts, procedures are available for mitigating physical damage to the environment. Often, it is just a question of balancing costs versus benefits. The perhaps larger issue of social and psychological disruption, which is one of the most dramatic consequences of a boom town syndrome, is primarily a result of the lack of planning and management in the timely provision of housing and services. Therefore, while growth and urbanization are inevitable impacts, except insofar as these are thought to be undesirable in themselves, the long range disadvantages of unsound settlement patterns, such as sprawl, and the immediate social and psychological disruption of the boom town, are in no sense an inevitable part of the problem, and can be avoided.

The effective management of growth also is related to the economic impacts, as well as the social and psychological impacts, of the proposed action. Equitable and efficient handling of the costs of municipal expansion can optimize the economic benefits to be derived from development. For example, the orderly provision of housing and services will reduce the inflation associated with unmet needs; effective planning can reduce the cost of municipal expansion by 30 percent to 40 percent; and policies to maximize local employment can both reduce the population impact and enhance the local economic benefits by increasing job opportunities, wage scales and public revenues.

It is the goal of this study to provide a mechanism for evaluating alternatives and tradeoffs, for making cost/benefit decisions, and for planning and managing adequately the environmental and socioeconomic aspects of synfuels development. Before detailing

how this is to be accomplished, however, it is necessary to describe the present framework of environmental regulation.

1.2 The Legislation

Over the past 10 years, public concern has been growing over the health hazards, social impacts, and environmental degradation that result from all forms of energy development. Emphasis in the early 1970's was placed on the immediate control of major sources of air and water pollution through the implementation of federal regulations. Most importantly, the requirements of the National Environmental Policy Act (NEPA) 1969, made it mandatory that an in-depth study of environmental impacts be made in connection with any new energy activity that may involve the federal government.

The following federal laws impact directly on power plant siting considerations:

- Clean Air Act
- Federal Water Pollution Control Act
- Resource Conservation and Recovery Act
- Toxic Substances Control Act
- National Environmental Policy Act

Other federal legislation indirectly affecting the siting of new energy facilities is shown in Table 1-1. Among the many considerations, permit applications to regulatory authorities must show careful examination of siting alternatives.

TABLE 1-1

FEDERAL LEGISLATION AFFECTING SITING OF NEW ENERGY FACILITIES

Clean Air Act of 1970
Federal Water Pollution Control Act Amendments of 1972
Marine Protection, Research and Sanctuaries Act of 1972
Coastal Zone Management Act of 1972
Noise Control Act of 1972
Federal Environmental Pesticide Control Act of 1972
Ports and Waterways Safety Act of 1972
Marine Mammal Protection Act of 1972
Endangered Species Act of 1973
Energy Supply and Environmental Coordination Act of 1974
Deepwater Port Act of 1974
Safe Drinking Water Act of 1974
Resource Conservation and Recovery Act of 1976
Toxic Substances Control Act of 1976
Federal Land Policy Management Act of 1976

The sweeping federal legislative program for environmental protection has led to the establishment of new complementary legislation, regulations, and requirements at state levels. A number of states already have enacted legislation analogous to NEPA. All states will eventually have extensive programs for environmental protection and control over power plant siting. At the close of the 1976 legislative session, 25 states had promulgated siting laws. At the end of April 1977, three additional states had siting bills before their legislatures, and 19 had introduced bills amending existing siting laws, or had initiated studies of siting legislation. (5)

Many states which do not have siting laws or legislative approvals exert influence over power plant siting by vesting this responsibility in state permit-issuing regulatory bodies. In Texas, for example, the Office of Planning Coordination serves as a focal point for state-level review of power plant licensing activities by other state departments or commissions.

Most of the local and state reviews, authorizations, and permit provisions are overlaid by a variety of state and federal/state planning programs. Thus, the regulatory framework in most states is a cross between a permit approach for specific facilities and a generalized planning approach for industrial development. Assurance of compliance with applicable plans is normally a requisite condition for any authorization to proceed with a project.

CLEAN AIR ACT

Under the Clean Air Act Amendments of 1970, the Environmental Protection Agency (EPA) is required to establish national air quality standards as well as national standards for significant new pollution sources and for all facilities emitting hazardous substances. It also provides a framework for the state to establish emission standards for existing sources in order to achieve the national air quality standards. State implementation plans are subject to EPA approval. EPA is authorized to enforce federal and state requirements by order of civil suit, including injunction relief. A private citizen may also bring suit to enforce the Act's provisions. Prior federal or state authorization is required for the construction of certain facilities which constitute new sources of air pollution.

In June 1974, the Act was amended by the Energy Supply and Environmental Coordination Act of 1974 to allow suspension of certain emission restrictions with regard to power plants and other major fuel burning installations ordered by the Federal Energy Administration to convert from clean fuels to coal. In August 1977, the Clean Air Act Amendments of 1977 were published. The amendments require that a Prevention of Significant Deterioration (PSD) Permit be filed for new power plant projects.

Two key concepts have emerged in connection with the law: nondegradation and nonattainment. The nondegradation concept limits the location of power plants where public dedicated lands might be subject to pollutant concentrations that degrade existing air quality. This is aimed at protecting "clean air regions." The nonattainment concept applies to the other end of the quality spectrum, namely regions already at or below federal air quality standards. For such "dirty" regions, additional sources of pollution may not be allowed unless there is at least an equivalent reduction of emissions from existing sources. (6)

FEDERAL WATER POLLUTION CONTROL ACT

The Federal Water Pollution Control Act Amendments of 1972 totally revised the previous act and established a comprehensive system of federal and state regulation of liquid effluent discharges into the public waters of the U.S. Waste heat resulting from condenser cooling of spent steam is treated as a pollutant under the law. The amended act required the establishment of effluent discharge limitations which by July 1, 1977 required the application of the "best practicable control technology currently available" and, by July 1, 1983, will require the application of the "best available technology economically achievable." The act established a national goal that the discharge of pollutants into public waters be eliminated by 1985, and that, wherever attainable, an interim goal of water quality suitable for the protection and propagation of fish and wildlife be achieved by July 1, 1983. (7)

For successful completion of a National Pollutant Discharge Elimination Systems (NPDES) permit, all industries using water for cooling purposes are required to conduct a demonstration, even if the plant is categorically exempt from thermal discharge. Certain minimum requirements must be met with respect to treatment of plant process waste streams. The permit may be issued for up to a five-year period.

RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act controls water pollution indirectly, by requiring a regulatory system for the treatment, storage, and disposal of hazardous wastes. The act defines solid waste as any discarded material resulting from industrial, commercial, mining, and agricultural operations, and from community activities. This does not include solid or dissolved material in wastewater discharges that are point sources and are subject to NPDES permits.

This act requires that regulations developed by EPA applicable to transporters of hazardous wastes subject to the Hazardous Materials Transportation Act be consistent with the requirements of the latter act. The EPA administrator is authorized to make recommendations to the Secretary of Transportation concerning the regulations of such hazardous waste under the Hazardous Transportation Act for the addition of materials to be covered by that act.

EPA must integrate all provisions of this act for purposes of administration and enforcement and must avoid duplication with other acts that grant regulatory authority to EPA.

TOXIC SUBSTANCES CONTROL ACT

The Toxic Substances Control Act gives the EPA broad discretionary authority to control chemical substances that pose an unreasonable risk of injury to health of the environment. Anyone who intends to manufacture or process a new chemical substance, or an existing chemical substance for a significant new use must first give EPA at least 90 days advance notice of intent. Upon review of such notification, the administrator determines whether or not to impose regulations.

The act also provides EPA with authority to require the testing of a chemical substance or mixture to determine the extent of its toxicity. Where the manufacture, processing, distribution in commerce, use or disposal of a chemical substance or mixture may present an unreasonable risk, or where there is insufficient data and testing may develop data from which to make a reasoned evaluation as to the effects on health and the environment, the administrator may require testing to be done by manufacturers and processors of such chemical substance or mixture. The act establishes an interagency committee with responsibility for drawing up a priority list of not more than 50 chemical substances for testing.

Of major significance to this act is that it provides authority to develop information on the impact of chemical substances on the water environment, and allows for broad control of chemicals.

NATIONAL ENVIRONMENTAL POLICY ACT

The terms "Environmental Impact Statement" and "Environmental Assessment" are related but they are not synonymous. It is important to emphasize the differences between them. An "Environmental Impact Statement" is prepared to obtain approval from a government regulatory agency in order to build a specific structure or technological system. It is a legal document. The impact statement is usually formulated to argue the case as to whether or not a specific facility can be constructed and operated in an environmentally acceptable manner at some preselected site.

An "Environmental Assessment" is primarily a planning tool. Its purpose is to uncover unexpected problems at the earliest possible time within the development program. In many cases, environmental assessments are conducted on energy systems for which commercial application is still many years away. This approach provides a futuristic perspective so that the maximum benefits of the program may be established. This may, however, involve making assumptions about future environmental regulations or source performance standards. (8)

The requirements for environmental impact statements were established by Congress under NEPA. NEPA directs all federal agencies to identify and develop methods and procedures which will ensure that presently unquantified environmental amenities and values are given appropriate consideration in decision making along with economic and technical considerations. The act directs that all agencies prepare a detailed statement on all actions significantly affecting the quality of the human environment. The statement is required to include:

- The environmental impact of the proposed action,
- Any adverse environmental effects which cannot be avoided should the proposal be implemented,
- Alternatives to the proposed action,
- The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
- Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

The act originally established that the President report to Congress annually concerning the environmental quality of the Nation, and also established the Council on Environmental Quality (CEQ) which was deemed responsible for the review of environmental impact statements. In 1977, under President Carter's government reorganization, the CEQ staff of 40 was virtually eliminated. EIS review responsibilities are now handled by EPA, and the remaining CEQ personnel are acting in an advisory fashion on environmental policies. (9)

1.3 Where This Study Fits In

This report serves as a companion document to the report, "Volume 1: Environmentally-Acceptable Fossil Energy Site Evaluation and Selection: Methodology and Users Guide," in which a methodology was developed which allows the siting of fossil fuel conversion facilities in areas with the least environmental impact. The methodology, known as SELECS (Site Evaluation for Energy Conversion Systems) does not replace a site specific environmental assessment, or an environmental impact statement (EIS), but does enhance the value of an EIS by thinning down the number of options to a manageable level, by doing this in an objective, open and selective manner, and by providing preliminary assessment and procedures which can be utilized during the research and writing of the actual impact statement.

This report, "Volume 2: Criteria for the Development and Use of the Methodology for Environmentally-Acceptable Fossil Energy Site Evaluation and Selection," presents the criteria, or the background material necessary for the development and use of the SELECS methodology. The concern here is with conversion of fossil fuels such as coal, oil shale, and tar sands into synthetic crude and/or natural gas. Presented is data on the available fossil fuel resources and their demand within the boundaries of the U.S. (Chapters 2 and 3). Chapter 4 examines DOE's role and support in the development of fossil energy technologies. Chapters 5 through 11 describe current technologies under development, including their processes, products, by-products, residuals, environmental controls, and gives descriptions and the status of selected on-going projects.

A discussion of potential fossil fuel conversion sites in the eastern, central, and western portions of the U.S. is presented in Chapter 12. Nine specific sites selected as case studies were applied to the SELECS methodology, the descriptions and results of which are summarized in Chapter 13. Three of the nine sites are examined in detail in the aforementioned companion document.

These reports were prepared through the joint efforts of Cameron Engineers, Inc., Denver, Colorado, and The Center for the Environment and Man (CEM), Hartford, Connecticut. Both CEM and Cameron Engineers worked under the direction of Dr. Ralph Scott of DOE's Pittsburgh Energy Research Center (PERC). These volumes culminate the efforts of eight months of work, and integrate the results of two previous studies both available through NTIS:

- "Methodology and User's Guide for Evaluating Socioeconomic and Environmental Impacts of Fossil Energy Conversion Facilities at Potential Sites," prepared by The Center for the Environment and Man, May 1978, and
- "Development of Environmental Guidelines for Fossil Energy Site Selection," prepared by Cameron Engineers, Inc., May 1978.

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CHAPTER 2

SURVEY OF FOSSIL ENERGY SOURCES

This chapter summarizes the information on available fossil fuel resources within the boundaries of the U.S. The concern here is with conversion of fossil fuels such as coal, oil shale and tar sands into synthetic crude and/or natural gas, and the presentation in this chapter is limited to a survey of only the above mentioned fossil energy resources.

2.1 Coal

As recently as World War II, coal was the principal source of energy in the U.S. In 1947, coal provided 48 percent of total U.S. energy demand. As of 1971, coal's share had been reduced to 18 percent of the total energy demand.

Coal is present in varying amounts in 37 states. The U.S. Geological Survey (U.S.G.S.) estimates that 13 percent of the total area of the 50 states is underlain by coal bearing rocks (2). It is estimated that, within 6,000 feet of the surface, the total coal resources* within the U.S. are approximately 3.2 trillion tons.** The estimate of coal resources within 3,000 feet of the surface is 2.9 trillion tons. Of the 3.2 trillion tons, 1.6 trillion tons are considered by the U.S.G.S. as hypothetical resources, i.e., resources which have been inferred purely on the basis of geological understanding and knowledge. The hypothetical resources may or may not be economically recoverable. The same is true of the remaining 1.6 trillion tons which are categorized as identified resources. Reserves# which are considered as economically recoverable resources have been estimated by the Bureau of Mines (1) as approximately 430 billion tons. The reserves include in-place quantities of bituminous coal and anthracite in beds 28 inches or more thick and subbituminous coal in beds 60 inches or more thick that occur at depths to 1,000 feet. It also includes lignite in beds 60 inches or more thick that can be surfaced-mined. Depending upon the location and geological occurrence of the coal bed, the amount of coal which can be recovered from a deposit ranges anywhere from 50 to 90 percent of the reserve base. Using an average figure of 70 percent as a material recovery rate, approximately 300 billion tons of coal are available for use under current economic conditions. It is noted that future changes in the economics of energy or technological breakthroughs in mining will substantially modify the estimates of coal reserve in the U.S. For example, it is estimated that an additional 1,285 billion tons of coal will be economically recoverable if coal prices increased 50 percent from the 1973 base price.

A distribution of coal resources, by category, of U.S.G.S. coal provinces is given in Table 2-1. (Coal resources by state are shown later in Table 2-3).

The location of these resources and the boundary of the coal provinces are shown in the energy value represented by these resources. The total energy value represented by

*Resources are all deposits that may eventually become available — either known deposits that are not economically or technologically recoverable at present or unknown deposits that may be inferred to exist but have not been discovered.

**Short tons (2000 lbs) are used throughout the text.

#Reserves are known identified deposits which can be extracted profitably with existing technology and under present economic conditions.

Figure 2-1. Distribution of United States Coal Resources.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

TABLE 2-1
COAL RESOURCES IN U.S. GEOGRAPHICAL SURVEY PROVINCES
(Billions of Tons)

Province	Identified	Hypothetical	Total
Eastern	276	45	321
Interior	277	259	536
Northern Great Plains	695	763	1,458
Rocky Mountains	187	395	582
Other	146	181	327
Total	1,581	1,643	3,224

Source: University of Oklahoma, 1975, Energy Alternatives: A Comparative Analysis.

identified sources is approximately 33,425 quadrillion Btu. Using an average of 10,500 Btu/pound of coal (average Btu value of identified sources), the estimated coal energy represented in the total coal resources of the U.S. is 67,2000 quadrillion Btu. Considering that the total U.S. energy consumption in the U.S. is currently at 75 quadrillion Btu, the coal resources have an energy value equivalent to 890 years of total U.S. energy consumption at the current rate. At the estimated 2000 rate of energy consumption of 128.5 quadrillion Btu per year, coal resources represent over 500 years of energy supply for total U.S. needs.

2.1.1 Distribution of Coal Resources

Figure 2-1, on the previous page, shows identified sources of coal in the U.S. As indicated in Figure 2-1, most of the coal in the U.S. exists in four geological provinces: Eastern Province, Interior Province, Northern Great Plains, and Rocky Mountain. A brief description of coal deposits in each province follows.

TABLE 2-2
ENERGY VALUE OF IDENTIFIED U.S. COAL RESOURCES

Rank	Identified Resources (billions of tons)	Energy Value* (Quadrillion Btu)
Anthracite	21	588
Bituminous	686	18,520
Subbituminous	424	8,480
Lignite	449	5,837
Total	1,580	33,425

Source: P. Averitt, in USGS Professional Paper 820, 1973, United States Mineral Resources.

*Based upon following energy values:

Anthracite	=	14,000 Btu/pound
Bituminous Coal	=	13,500 Btu/pound
Subbituminous Coal	=	10,000 Btu/pound
Lignite	=	6,500 Btu/pound

a. The Eastern Province

The Eastern Province includes three regions: Appalachia, Pennsylvania Anthracite, and Atlantic Coast. Figure 2-2 shows the location of coal deposits in the Eastern Province. The estimated identified resources in this province are 276 billion tons. Of the 276 billion tons, 21 are anthracite. There are no other major anthracite coal beds in the U.S. The remaining coal deposits in the province are, in general, high-ranked bituminous coal. The recoverable quantity is estimated at 122 billion tons. Approximately 65 percent of the coal in this province has a sulfur content of more than 1 percent. Most of the coal lands in this province are privately owned.

b. The Interior Province

The Interior Province includes all or portions of Michigan, Illinois, Indiana, Kentucky, Iowa, Missouri, Arkansas, Nebraska, Kansas, Oklahoma, and Texas. Figure 2-3 locates the coal deposits of the Interior Province. Of the 277 billion tons of identified sources, only 102 are considered recoverable. Most of the coal in this province is of the bituminous type. Most coal lands are privately owned.

c. The Northern Great Plains Province

The Northern Great Plains Province includes areas of deposit in North Dakota, South Dakota, Montana, Wyoming and Colorado. Most of the coal in this province is of low Btu type. The deposits in North Dakota are mostly lignite and deposits in the eastern portion of Montana and Wyoming are subbituminous. However, approximately 44 percent of the coal in this province is low sulfur coal. Out of the total 695 billion tons of identified resources, only 106 are considered recoverable. Figure 2-4 locates the coal deposits of this province. Much of this coal land is owned by the Federal Government.

d. The Rocky Mountain Province

The major coal deposit in the Rocky Mountain Province includes deposits in western Wyoming, deposits in the northern region of the border between Colorado and Utah, and deposits in the southwestern corner of Colorado and northwestern portion of New Mexico. The variety of coal in this province is great and heating values range from 5,000 to 14,000 Btu/pound of coal. Almost 90 percent of the coal has a sulfur content of less than one percent. Of the identified resources of 187 billion tons, only 37 are considered recoverable. The coal deposits in this province are shown in Figure 2-5. The Federal Government has jurisdiction over many of these coal lands.

For the four provinces, the Bureau of Land Management estimates the recoverable quantity of coal at 367 billion tons. The previously noted 430 billion tons of recoverable coal reported by the Bureau of Mines includes coal in other parts of the country (Gulf Province and Coast Province) and coal resources which are currently being mined, even though not considered recoverable from the strict point of view of depth and seam thickness requirement.

Table 2-3 presents the coal resources of each state and energy equivalent of the resources. The states having high values of coal energy are: North Dakota, 4560

Figure 2-2. Location of Coal Resources in The Eastern Province.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

Figure 2-3. Location of Coal Resources in The Interior Province.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

Figure 2-4. Location of Coal Resources in The Northern Great Plains Province.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

Figure 2-5. Location of Coal Resources in the Rocky Mountain Province.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

TABLE 2-3
ESTIMATED COAL RESOURCES OF STATES

State	Area Underlain by Identified Coal Deposits		Coal Resources of States (million tons)					Energy Value of Identified Resources	
	Area Sq. Miles	% of Total State Area	Identified Resources				Identified & Hypothetical Coal Resources	Total Energy Quadrillion Btu	% of U.S. Coal Energy
			Anthracite	Bituminous	Subbituminous	Lignite			
Alabama	9,700	19	0	13,342	0	2,000	41,342	386	1.15
Alaska	35,000	2	-- ²	19,413	110,668	-- ¹	265,081	2,739	8.19
Arizona	3,040	3	0	21,246	-- ³	0	21,246	574	1.72
Arkansas	1,700	3	430	1,638	0	350	6,418	60	0.20
Colorado	29,600	28	78	62,339	18,242	0	371,659	2,050	6.13
Georgia	170	0.2	0	24	0	0	84	1	0.0
Illinois	37,700	67	0	139,124	0	0	239,124	3,756	11.23
Indiana	6,500	18	0	34,573	0	0	56,573	933	3.03
Iowa	20,000	36	0	6,509	0	0	20,509	176	0.57
Kansas	18,800	23	0	18,674	0	-- ⁴	22,674	504	1.64
Kentucky	14,600	36	0	64,842	0	0	116,842	1,751	5.69
Maryland	440	4	0	1,158	0	0	1,558	31	0.10
Michigan	11,600	20	0	205	0	0	705	6	0.02
Missouri	24,700	35	0	31,014	0	0	49,214	837	2.72
Montana	51,300	35	0	2,299	131,855	87,521	378,675	3,837	3.70
New Mexico	14,650	12	4	10,752	50,671	0	109,427	1,304	4.24
N. Carolina	155	0.3	0	110	0	0	135	3	0.01
N. Dakota	32,000	45	0	0	0	350,630	530,630	4,558	13.63
Ohio	10,000	24	0	41,358	0	0	43,358	1,117	3.63
Oklahoma	14,550	21	0	3,281	0	0 ⁵	33,281	89	0.29
Oregon	600	0.6	0	50	284	0	434	7	0.02
Pennsylvania	15,000	33	20,510	56,759	0	0	87,269	2,107	6.85
Rhode Island	100	5	-- ⁵	0	0	0	0	0	0.0
S. Dakota	7,700	10	0	0	0	2,031	3,031	26	0.08
Tennessee	4,600	11	0	2,572	0	0	4,572	69	0.22
Texas	16,100	6	0	6,048	0	6,824	26,872	252	0.82
Utah	15,000	18	0	23,541 ⁶	180 ⁶	0	79,721 ⁷	639	2.08
Virginia	1,940	5	335	9,352	0	0	14,787	262	0.85
Washington	1,150	2	5	1,867	4,190	117	51,179	136	0.44
W. Virginia	16,800	69	0	100,628	0	0	100,628	2,717	3.12
Wyoming	40,055	41	0	12,705	107,951	0	545,656	2,502	7.48
Other States	1,350	-	0	610 ⁸	32 ⁹	46 ¹⁰	1,698	18	0.06
Total	458,600	13 ¹¹	21,362	686,033	424,073	449,519	3,224,372	33,446	100.00

¹Small resources of lignite included under subbituminous coal.

²Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable.

³Includes coal in the Dakota Formation of the Black Mesa field, some of which may be of subbituminous rank. Does not include small resources of thin and impure coal in the Deer Creek and Pinedale fields.

⁴Small resources of lignite in beds generally less than 30 in. thick.

⁵Small resources of meta-anthracite in the Narragansett basin believed to be too graphitic and too badly crushed and faulted to be economically recoverable as fuel.

⁶Excludes coal in beds less than 4 ft thick.

⁷Includes coal in beds 14 in. or more thick, of which 14,000 million tons is in beds 4 ft or more thick.

⁸California, Idaho, Nebraska and Nevada

⁹California and Idaho

¹⁰California, Idaho, Louisiana, and Mississippi

¹¹Percent of total area of the fifty states.

Source: P. Averitt, in USGS Professional Paper 820, 1973, United States Mineral Resources.

quadrillion Btu and Illinois, 3760 quadrillion Btu. Other states with more than 1700 quadrillion Btu equivalent coal energy are: Alaska, Colorado, Kentucky, Pennsylvania, West Virginia and Wyoming. These eight states contain 67 percent of the nation's coal energy.

2.1.2 Ownership of Resources

The Federal Government owns approximately 48 percent of all coal lands in Alaska, Colorado, Montana, North Dakota, Oklahoma, Utah and Wyoming. In these states, the Federal ownership percentages range from 4 percent in Oklahoma to 97 percent in Alaska. In general, coal lands in the Rocky Mountain Province are owned by the Federal Government, Indian tribes and railroad companies, while coal lands in the eastern and midwestern states are privately owned.

2.2 Oil Shale

Oil shale is not shale and it does not contain oil; rather, it is a sedimentary rock containing Kerogen — an insoluble organic matter which upon retorting yields oil similar to natural crude oil.* No successful commercial oil shale venture has existed in the U.S. in the past 100 years. Commercial oil shale operations exist in China, Sweden and Spain. Raw oil shale is burned in electric power plants in Estonia and the Federal Republic of Germany (2).

The USGS infers the total resources of oil shale within 10,000 feet from the surface at 26 trillion barrels of oil in low oil yielding shale and another 1.3 trillion barrels in high oil yielding shale. This estimate of oil shale includes carbonaceous shales associated with coal beds. However, very little of the shale resources can be classified as reserve, i.e., known to exist and to economically recoverable. The USGS estimates that 418 billion barrels of oil can be produced from 6 trillion tons of oil shale from identified shale resources which produce at least 30 or more gallons of oil per ton of oil shale (equivalent to 25-100 gallons/ton category), and these deposits are closest to being categorized as reserves.

Another study by EPA (3) indicates that 33 billion barrels of oil can be produced from deposits of 38 billion barrels of oil can be produced from deposits of 38 billion tons of oil shale which would yield 35 gallons of oil/ton of shale and has seams at least 30 feet thick. An additional 400 billion barrels of oil are available from 700 billion tons of oil shale deposits which yield at least 25 gallons of oil per ton with seam thickness of at least 30 feet. The quantity of shale which can be considered as reserves is highly dependent upon the economics of other sources of energy. The National Petroleum Council's 1972 review of the U.S. energy outlook indicated that 129 billion barrels of oil were recoverable under 1972 conditions. On the other hand, the Department of Interior's final Environmental Impact Statement for its Prototype Oil Shale Leasing Program estimated that 80 billion barrels were recoverable under 1973 conditions. Even the lower estimate of energy in oil shale is larger than the total U.S. energy reserves of oil and gas. Table 2-4 presents the USGS estimate of the oil shale resources at the U.S. The 1974 estimate of the cost of producing syncrude from oil shale is about \$11.50/bbl of oil (5). The cost of producing raw shale oil (not of the same grade as syncrude) by Paraho is quoted as \$10.78/bbl (1978 dollars) (6).

*Oil shale is called "Kerogenous Marlstone."

TABLE 2-4
OIL SHALE RESOURCES OF THE U.S.¹
(Billions of Barrels of Oil Yield)

Feasibility of Recovery	Knowledge of Resource*			EPA Estimate of Identified Reserves**
	Identified ²	Undiscovered ³		
		Hypothetical ⁴	Speculative ⁵	
Recoverable	0	0	0	433 ⁸
Paramarginal ⁶	418	300	600	
Submarginal ⁷	1,600	1,600	23,000	

*University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.

**U.S. EPA, Control of Environmental Impacts of Advanced Energy Sources, EPA Report 600/2-79-002, 1974.

¹Reliability of estimate decreases downward and to the right. This analysis is based on 1973 estimates.

²Specific bodies known from geological evidence supported by engineering measurements.

³Unspecified bodies of mineral-leasing material surmised to exist on the basis of broad geologic knowledge and theory.

⁴Undiscovered materials that may reasonably be expected to exist in a known mining district.

⁵Undiscovered materials that may occur either in known types of deposits in a favorable geologic setting where no discoveries are made or in as yet unknown types of deposits that remain to be recognized.

⁶That portion of subeconomic resources that (1) borders on being economically producible, or (2) is not commercially available solely because of legal or political circumstances. In general, this category includes shale with a yield of 25 to 100 gallons/ton.

⁷The portion of subeconomic resources which would require a substantially higher price (more than 1.5 times the price at the time of determination) or a major cost-reducing advantage in technology. In general, this category includes shale with a yield of 10-25 gallons/ton.

⁸The term "recoverable reserve," as used by EPA, indicates the reserves which may be recovered in this century.

2.2.1 Distribution of Oil Shale Resources

Oil shale in the U.S. is associated with three distinct geological formations. They are the Green River Formation, Chattanooga Shale, and a general designation of other deposits. Figure 2-6 shows the location of shale deposits in the U.S. A brief description of oil shale resources in each of the geological formations follows.

a. Green River Formation

The Green River Formation in Western Colorado, Utah and Wyoming is the principal oil shale deposit of lacustrine origin. Out of the 25,000 square miles of land underlain by the Green River Formation, 17,000 square miles contain shale deposits with high commercial development potential. The Green River Formation accounts for 90 percent of the identified oil shale resources of the U.S. Small lacustrine origin deposits also occur in the intermountain basins of Montana, Nevada, Idaho and California. However, most of these deposits are unexplored.

It is estimated that in the Green River Formation 418 billion barrels of oil are available in high grade shale (average of 30 gallons of oil per ton of shale) and another 1,400 billion barrels are available in low grade shale (average shale) yield less than 30 gallons of oil per ton of shale). Within the Green River Formation, the largest accumulation of Kerogen (equivalent to 355 billion barrels of oil) exists in the Piceance Creek Basin located in Colorado and bounded by the White River in the north and the Colorado River in the south. Another 50 billion barrels exist in the Uinta Basin of Utah and 13 billion barrels in the southeastern portion of the Green River Basin Wyoming. The USGS estimates the hypothetical resource of oil shale in the Green River Formation at 650 billion barrels of oil.

TABLE 2-5
DISTRIBUTION OF IDENTIFIED OIL SHALE RESOURCE
WITHIN GREEN RIVER FORMATION

Location	Identified Resources of High Yield Shale* (Billion Barrels of Oil)
Piceance Creek Basin in Colorado	355
Uinta Basin in Utah	50
Green River Basin in Wyoming	13
Total	418

* Average yield of more than 30 gallons/ton, oil yield in the deposits ranging from 25 to 100 gallons/ton of shale.

Figure 2-6. Distribution of the Oil Shale Resources of the U.S.

Source: *Energy Alternatives: A Comparative Analysis*,
University of Oklahoma, 1975.

b. Chattanooga Shale

Chattanooga Shale and equivalent formations occur in large areas in the central and eastern United States. Geologically they are of marine origin. Substantial deposits of this type of shale occur in Tennessee, Kentucky and Indiana. The oil yield of this shale is low and ranges between 1 to 15 gallons of oil per ton of shale.

The identified resources of this shale is estimated by USGS at 200 billion barrels of oil. The estimate for hypothetical resources is 800 billion barrels.

c. Other Shale Deposits

In Alaska, rocks of marine origin contain oil shale. In eastern Alaska, near the Nation River, oil shale deposits are reported to yield as much as 30 gallons of oil per ton and seams are 200 feet thick. On the north slope area, thin seams (5 feet or less) of oil shale are reported to yield up to 160 gallons of oil per ton of shale. This shale also contains unusually high concentrations of trace elements such as silver, gold, and mercury.

The USGS estimates the hypothetical resource of the Alaskan oil shale deposits at 450 billion barrels of oil, of which 200 billion barrels are in high grade shale.

Oil shale also occurs in association with coal beds. These deposits generally are small in extent and occur in thin seams. The significant sources of such oil shale deposits are the coal deposits of Appalachia and Pennsylvania. In general, the oil yield from this shale is less than 10 gallons per ton of shale. Identified resources of this type of oil shale are limited and no estimate exists on the hypothetical resource of such shale.

Table 2-6 summarizes the oil shale resources of the U.S. Table 2-7 presents the area underlain by identified resources of oil shale on a state-by-state basis.

2.2.2 Ownership of Oil Shale Deposits

As indicated earlier, 90 percent of the U.S. oil shale resources is in the Green River Formation, and this resource has the highest potential for commercial development. It is estimated that 80 percent of the high grade shale land in the Green River Formation is owned by the Federal Government. However, the title for about 85 percent of the federal oil shale land has not been clearly established and may be disputable (4). Three quarters of the private oil shale land is owned by seven firms.

2.3 Tar Sands

The National Petroleum Council identifies tar sands as deposits of porous rock or sediments that contain hydrocarbon oil (tar) too viscous to be extracted by conventional petroleum recovery methods. So far in the U.S., commercial exploitation of tar sands for oil production has been limited to small-scale development deposits in Utah. In Canada, however, 45,000 barrels of oil per day are being produced from tar sands in Alberta by Great Canadian Oil Sands, Ltd. Another plant by Syncrude Canada, Ltd., is expected to come on line by July 1978.

TABLE 2-6
LOCATION OF OIL SHALE RESOURCES*
(Billions of Barrels Oil Yield)

Location	Identified*		Hypothetical*		Speculative*	
	25-100** Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton
Green River Formation (Colorado, Utah, and Wyoming)	418	1,400	50	600	0	0
Chattanooga shale and equivalent formations (Central and Eastern U.S.)	0	200	0	800	0	0
Marine shale (Alaska)	Small	Small	250	200	0	0
Other shale deposits	0	Small	NE	NE	600	23,000
Total	418+	1,600+	300	1,600	600	23,000

NE = not estimated.

Source: W. C. Culbertson and J. K. Pitman in USGS Professional Paper 820, 1973,
United States Mineral Resources.

*For definition of categories, see Table 2-4.

**The category 25-100 gallons per ton is equivalent to the category, "average of
30 or more gallons per ton."

TABLE 2-7
AREA UNDERLAIN BY OIL SHALE DEPOSITS

State	Area Underlain by Identified Oil Shale		Region of State Underlain by Oil Shale	Grade of Oil Shale	% of Natural Resource
	Total Area Sq. Miles	% of Total State Area			
Alabama	10,300	20	North	Low	= 1
Alaska	17,000	3	Northern	Low	= 1
Arkansas	13,000	25	West	Low	= 1
California	1,500	<1	Southwest	Low	= 1
Illinois	28,000	50	Southeast	Low	= 1
Indiana	25,000	70	West	Low	= 1
Kentucky	36,000	90	Central	Low	= 1
Michigan	35,000	60	South	Low	= 1
New York	2,500	5	Southwest	Low	= 1
Pennsylvania	13,600	30	West	Low	= 1
Oklahoma	42,000	60	Eastern half	Low	= 1
Tennessee	25,000	60	Central	Low	= 1
Texas	26,000	10	Central, NE, West	Low	= 1
Colorado	5,500	5	Northwest	High	30
Utah	10,200	12	Northeast	High	30
Wyoming	9,300	10	Southwest	High	30
Total Area	322,900	9*			

*Percent of the total U.S. area of 3.6 million sq mi.

According to the USGS, the identified resources of tar sands in the U.S. are on the order of 30 billion barrels of oil. The major deposits of tar sands in the world exist in Columbia, Venezuela and Canada. The Department of the Interior believes that in 15 to 30 years it may be feasible to begin recovery of one-third (10 billion barrels of oil) to one-half (15 billion barrels of oil) of the resources. The Bureau of Mines' estimate of recoverable resources ranges from 2.5 to 5 billion barrels (1). The estimate is based upon utilization of shallow tar sands only and reflects the technology and economic conditions of 1973. Most of the current use of tar sands in the U.S. is as asphalt for road building.

2.3.1 Distribution of Tar Sands

Figure 2-7 shows the distribution of tar sands in the U.S. The USGS reported a study by Ball Associates which listed 546 occurrences of tar sands in the 22 states of the U.S. However, of the 22 states, only California, Kentucky, New Mexico, Texas and Utah have tar sands deposits with energy value of more than one million barrels of oil. The USGS estimate of resources in these states is given in Table 2-8. Of the identified resources, more than 95 percent exist in Utah in the Uinta Basin and in a triangle-shaped area (Tar Sands Triangle) west of the confluence of the Green River and the Colorado River. Other states which have significant tar sands deposits are Alabama, Alaska, Kansas, Missouri, and Oklahoma. Information on tar sands deposits of Alaska is very limited.

2.3.2 Ownership of Tar Sands Deposits

The Federal Government owns the major tar sands deposits in Utah. It is noted that extensive deposits of tar sands occur in the Uinta Basin and the Ouray Indian Reservation (4). Most of the deposits located outside Utah are on private lands.

TABLE 2-8
SIZE OF U.S. TAR SAND DEPOSITS
(Known deposits of at least one million barrels)

State	Reserves [#]	Resources ^{##} (Millions of barrels)
California	2	269-322
Kentucky	U*	33-37
New Mexico	U*	57
Texas	U*	124-441
Utah	1,000-5,000 ^{**}	18,693-28,862

*Unknown.

**These "reserves" are apparently not presently recoverable. They could be appropriately termed para-marginal reserves.

[#]Identified or undiscovered deposits that are currently or potentially feasible to extract.

^{##}Identified deposits that can be extracted, processed and sold on a profitable basis under current market conditions.

Source: University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.

Figure 2-7. Distribution of the Tar Sands Resources of the U.S.

Source: *Energy Alternatives: A Comparative Analysis*.

References for Chapter 2

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5. The Oil & Gas Journal, "Union Claims Boost in Shale-Oil Technology," June 1974, Page 76-77.
6. Cameron Engineers, Synthetic Fuels Quarterly, Denver, Colorado, March 1978.

CHAPTER 3

DEMAND FOR FOSSIL ENERGY

The need and the subsequent development of large-scale fossil fuel facilities cannot be determined without a comprehensive understanding of the magnitude and division of future energy and fuel demand in the United States. The objective of this chapter is to develop a credible energy demand scenario for 1980 through 2020.

There are basically four major energy-consuming sectors: residential, commercial, transportation, and industrial. Historic consumption patterns were reviewed (1,2,3) and projected through 2020. These projections were based on assumptions relative to Government policy, economic trends, population trends and social trends. Consideration was also given to existing projections from a number of sources (1,2,3,4,5,6,7,8,9).

Energy demand is closely tied to future circumstances affecting U.S. energy supply and demand. National consumption of energy is primarily a function of population and the rate of growth and productive mix of gross national output (GNP). Over the past 40 years there has been good correlation between *per capita* energy consumption and *per capita* GNP. This relationship may change in the future. For the first time in the recent history of the United States, energy costs will have a limiting influence on the rate of economic growth and the consequent demand for energy. During the decade of the Sixties, GNP grew at an annual rate of 4.57 percent. This growth rate may fall to 3.0 - 3.5 percent or lower through the year 2000, unless the real costs of energy are reduced by some means not presently apparent. Manufacturing production will strive for energy efficiency to reduce costs. In addition, there has been and continues to be a switch in overall national productive output from energy-intensive manufacturing to less energy-intensive services. The future is likely to see a lowered rate of increase of energy demanded per dollar of GNP.

National economic growth and energy demand are directly linked to population growth. Historically, *per capita* consumption of energy has grown at a much slower rate than has the overall energy demand, primarily due to the leverage of technology. There is an intuitive limit to *per capita* energy consumption; therefore the present reduction in the rate of population growth is likely to have a dampening effect on future energy demand.

Based on this rather conservative growth scenario for both the economy and the population, the total demand for energy in the United States is projected here as a composite of the demands from the four individual consuming sectors. Table 3-1 shows population projections (10), projected energy demand, and the calculated *per capita* consumption of energy. The resultant growth in population and *per capita* consumption of energy is illustrated in Figure 3-1. Note that even with a low growth background, by 2020 *per capita* demand will almost double today's level. However, it is important to note that the projection suggests that these energy demands, which more than doubled between 1950 and 1970 (20 years) will not double between 1980 and 2020 (40 years). Thus, we are suggesting that for the foreseeable future, energy will follow a sigmoid (s-shaped) curve, rather than the exponential growth of the past several decades. Comparisons of several existing U.S. energy demand projections are presented in Table 3-2.

(a) Obers series F population projection.

(b) Projected per capita energy consumption in the U.S.

(c) Actual and projected decade increase in per capita energy consumption.

Figure 3-1. Actual and projected population and per capita energy consumption.

TABLE 3-1
PER CAPITA ENERGY CONSUMPTION IN THE U.S.
[Quadrillion (10^{15}) Btu/yr]

Year	Population* (Millions)	Projected Energy Demand	Projected Per Capita Energy Consumption Millions Btu	Decade Change In Per Capita Energy Consumption Millions Btu
1950	150	34.1	227	22
1960	181	45.1	249	87
1970	205	68.8	336	69
1980	222	90.0	405	67
1990	239	112.9	472	40
2000	251	128.5	512	36
2010	259	142	548	14
2020	265	149	562	

*The Obers Series F population projection assumes a birthrate of 1.8 children per woman at end of child-bearing age [10].

TABLE 3-2
COMPARISON OF EXISTING PROJECTIONS OF U.S. ENERGY DEMAND
[Quadrillion (10^{15}) Btu/yr]

Source	1985	2000	2020	Date of Forecast
CEM	100	128.5	149	1978
ERDA [6]	96	135	-	1975
EPA [6]	105	154	-	1973
Exxon [9]	100	120	-	1977
Shell [7]	101.6	130.2	-	1977
Ford [6]	96	118	-	1974
FEA [6]	98	120	-	1974
CEQ [6]	92	121	-	1974

3.1 Projected Energy Demand by Sector

3.1.1 Background and Description of Consumption Sectors

Energy consumption in the U.S. is generally apportioned among four consuming sectors; residential, commercial, industrial, and transportation.* The residential and commercial sectors represent all public and private buildings to include shopping centers and other commercial establishments, government buildings, recreation centers, apartment buildings and individual residences. Mining and manufacturing industries are the largest energy users in the industrial sector. The transportation sector consists primarily for automobile, truck, airplane, rail and shipping consumption.

In 1950, the residential sector accounted for 19% of the energy consumed in this country, commercial 16%, industrial 38%, and transportation 27% (1,2). Although energy consumption, considered in total, grew from about 34.1 Q** in 1950 to about 75 Q by 1974, the proportionate consumption from the consuming sectors stayed reasonably constant. This was a period of cheap energy and rapid growth of population and national productive output. In 1970-71, the nation began experiencing a reduction in population growth rate that has continued to this time, although there are some present signs that the decline may have bottomed or reversed. The Arab oil embargo in 1973 was also an impetus for a dramatic change in energy consumption patterns; energy was no longer a "shadow factor" in production but a significant cost item. This new cost consciousness coupled with the slowed population growth are assumed here to be the dominant factors for projecting the future energy demands of the consuming sectors.

3.1.2 Demand Projections by Consumption Sector

Residential Energy Demand

The demands from the residential sector represented about 21% of total energy demand in 1974 (11). The tremendous growth in rate of residential consumption from 1950 through 1973 is no longer evident. Homes and other residence already constructed are essentially saturated with energy consumptive devices. Faced with substantially higher energy costs since 1973, conservation measures have been and are being implemented in existing and new dwellings to reduce per-residence energy consumption. Insulation of buildings, hot water pipes, hot water heaters, airducts, and more frequent maintenance of heating units are likely major conservation measures, as are turning off unused lights and lowering thermostat settings. New construction has been curtailed in response to more conservative population growth projections and an inventory of unsold buildings resulting from "overbuild" in the late 1960's and early 1970's. In addition, new construction will be more energy efficient to reflect the likelihood of continually escalating energy costs.

*In fact, there is really little standardization in energy projections. Often residential and commercial are combined. Sometimes commercial and industrial are combined. Sometimes gross energy used to produce electricity for the four sectors is included. Other times only net electrical energy used is given. It is a somewhat difficult process to unravel a rather confused past.

**Throughout this report, we will use the term Q to mean 10^{15} British thermal units (Btu).

In the future to 2020, we expect that there may be a small (10 to 15 percent or less) shift to the use of direct solar and wind systems to replace some of the conventional sources of residential energy. Much of this will probably be in the form of domestic hot water heating, because space requirements for heat storage can be small and it is simple to have an electric backup unit. There is little optimism about early use of solar or wind for space heating, because of high initial costs, large heat storage volume requirements, intermittancy of supply, and the need for a sizeable backup unit. Perhaps DOE-funded research will ameliorate these drawbacks, by providing a basis for production-line cost reductions.

Based on this conservative growth scenario, the historical trends in residential energy demands were projected through 2020. Figure 3-2 shows this projection. The rapid reduction in rate of growth shown from 2000 to 2020 is primarily a result of the conversion of energy inefficient homes and a reduction in new housing construction to reflect the slowing growth of the population.

Commercial Energy Demands

Energy demands from the commercial sector will likely continue to grow in response to the growth in Government at all levels and the growth in the service sector of national productive output (GNP). Conservation measures designed to reduce costs will be a moderating influence. Direct solar and wind systems may come into use more rapidly in the commercial sector, because the high initial costs can be financed more easily and there is a desire to become at least partially independent of outside energy sources for competitive reasons. Within these guidelines a likely schedule of commercial energy demands was projected from historical data. Figure 3-3 shows this projection.

Figure 3-2. Residential energy demand.

Figure 3-3. Commercial energy demand.

Industrial Energy Demand

The industrial sector will likely assume a larger proportion of overall energy demand in the future. In the short term, demands from this sector will be moderated by economic "slow downs" and conservation measures designed to reduce costs. As the economy recovers in the 1980s, however, and more energy intensive mining efforts are required to provide fuel for energy conversion, renewed growth in industrial energy demand is probable. In addition, technology is expected to continue to replace human laborers with energy-intensive mechanical devices. It is likely that this will be no more than a linear growth over the 1980-2010 period, and will begin to show a reduction in growth rate in the decade of 2010. This reduction will result as mining efforts peak and become more efficient and production and construction activities become saturated with energy-intensive equipment. The industrial demand projection is shown in Figure 3-4.

Transportation

Energy demand growth rates from the transportation sector will likely drop below historic rates. Although the new car production is likely to be stable or increase over the projection period, these cars will be lighter and substantially more energy efficient. It is also very likely that energy efficient and functional mass transit systems will be slowly phased into urban transportation plans. On the commercial transportation front, freight hauling will involve substantial energy costs which will be an impetus to develop more efficient methods of hauling and transporting these loads.

Figure 3-4. Industrial energy demand.

Figure 3-5. Transportation energy demand.

An eventual leveling or decline in energy demand is likely in this sector. Figure 3-5 shows our estimated demand schedule through 2020. The decline in transportation energy demand after 1990 is assumed to stem from a virtually complete replacement of all pre-1977 vehicles with smaller and/or much more efficient cars; and, also, a reduction in business travel due to vastly improved communication systems. Effective mass transit will also be an important factor in the reduction of energy consumed by commuters in private automobiles.

Total Energy Demand

The overall energy demand scenario for the United States is derived from the addition of the demands from its four primary consuming sectors as shown in Table 3-3. This composite demand is illustrated in Figure 3-6.

3.2 Projected Energy Demand by Fuel Form

3.2.1 Consuming Sector Demands by Fuel Form

The next step in this task is to generate a likely scenario for demands on prime energy sources required to fulfill overall energy demand. Historical energy source patterns were reviewed and projected for each consuming sector (1,3,6,9,12). The projections are not direct extrapolations of past trends. Probable fuel costs, fuel availability, along with likely political and environmental restraints were also considered.

Residential and Commercial

In the residential and commercial sectors, demand growth will be met primarily by gas and electricity. Oil consumption will increase only moderately, due to considerations of prices and convenience which favor other choices of fuel.

Solar is not projected to be a significant factor in either sector before the turn of the century. It is used primarily to augment existing power systems, and capital costs associated with installation are, in many cases, prohibitively high. The commercial sector will be better able to absorb these costs and will see an earlier introduction of solar power. Figures 3-7 and 3-8 illustrate the projected consumption by source for the residential and commercial sectors respectively.*

Industrial

Fuel source demands in the industrial sector are likely to exhibit more shifting and substitution than the other sectors. Historically, natural gas has been the predominant industrial fuel. Its use in this sector has probably peaked and will decline slowly in absolute terms as availability becomes a problem.

Priority for natural gas will be given to the residential and commercial sectors who are less capable of absorbing the costs associated with fuel source substitution. Increased demand will be met by substantial increases in coal and electrical consumption

*Figures 3-7, 3-8, 3-9, and 3-10 all show estimates of projected demand for energy in its final form. At this stage, no distinction is made concerning whether the required oil or gas comes from petroleum, natural gas, coal, shale oil, tar sands, etc.

TABLE 3-3
COMPOSITE TOTAL U.S. ENERGY DEMAND SUMMARY BY CONSUMING SECTOR

Consuming Sector	Actual ⁽¹⁾						Projected					
	1950		1960		1970		1980		2000		2020	
	Q ⁽²⁾	%	Q	%	Q	%	Q	%	Q	%	Q	%
Industrial	12.96	38	16.69	37	25.46	37	32.0	35.2	48.1	37	62	42
Commercial	5.46	16	7.21	16	11.7	17	16.4	18.3	28.0	22	33.5	22
Residential	6.48	19	9.47	21	15.14	22	19.6	22	29.4	23	32.5	22
Transportation	9.2	27	11.73	26	16.5	24	22.0	24.0	23.0	18	21	14
Totals	34.1	100	45.1	100	68.8	100	90	100	128.5	100	149	100

Notes:

1. Data for 1950, 1960, and 1970 come from References 1 and 2.
2. Q = Quadrillion Btu.

Figure 3-6. Total U.S. energy demand as a composite for consuming sector demands.

Figure 3-7. Residential energy demand by fuel form.

Figure 3-8. Commercial energy demand by fuel form.

and moderate increases in oil use. Solar technology is not likely to be a significant factor in industrial consumption throughout the projection period. Figure 3-9 shows these projected trends in energy consumption.

Transportation

Transportation is almost entirely dependent on oil. Motor gasoline use currently accounts for up to three-quarters of the transportation demand. The remaining demand is filled by aviation and diesel fuels, heavy fuel oil, liquefied petroleum gas, and electricity. Projected consumption demand for this sector is shown in Figure 3-10.

3.2.2 Energy Form Requirements for Electricity

The demand for electricity represents a "pull-through" demand on the primary fuel sources (coal, oil, gas, hydro, nuclear). In order to project total energy form demands it is therefore necessary to project a likely fuel source scenario to meet the electrical generation requirements projected in the previous section.

Historical patterns in the electrical generating industry were reviewed (2,3,13). Projections through the year 2020 were made based on the availability of fuel resources and the practical expansion of electrical generating facilities within a frame work of likely political, economic, environmental and technological restraints. These projections are shown in Figure 3-11 and Table 3-4. The energy demand shown is that required as input for the electrical generators. The amount of electrical energy generated (output) is approximately one-third of the input energy.*

*As a reasonable approximation:

$$3Q \text{ (input energy)} \rightarrow 1Q \text{ (electric energy)} = 293,000 \text{ million kwh.}$$

Figure 3-9. Industrial energy demand by fuel form.

Figure 3-10. Transportation energy demand by fuel form.

Figure 3-11. Projected fuel source demand to meet electrical generation requirements.

3.2.3 Composite Energy Demands by Form

The total projected demands on energy sources are the composites of the primary sector demands and the "pull through" demands resulting from electrical generation. Tables 3-5 through 3-8, summarize the breakdown of consuming sector energy demand by fuel form. The composite fuel form requirements are shown in Figure 3-12 and Table 3-9.

3.3 Credible Scenario for Fossil Energy Consumption

3.3.1 Direct Consumption

The primary fossil fuels are coal, oil, and natural gas. Figure 3-12 in the previous section shows a probable scenario for demands on all fuel forms. The likely demands on fossil fuel resources are reproduced separately in Table 3-10.

Since domestic supplies of these fossil fuel forms are not directly linked to their demands, Table 3-10 does not, in the strictest sense, represent direct consumption. A portion of coal consumption will be used to convert to oil and gas to meet likely shortages of these fuel forms projected in the following section (3.3.2). This is a secondary consumption of coal derived from demands for oil and gas.

TABLE 3-4
ENERGY SOURCES REQUIRED TO MEET ELECTRICAL DEMAND
[Q = Quadrillion (10^{15}) Btu/yr]

Year	Hydroelectric		Natural Gas		Oil		Coal		Nuclear		Total	
	Q	%	Q	%	Q	%	Q	%	Q	%	Q	%
1950	0.5	12	0.6	15	0.6	15	2.3	58	-	-	4.0	100
1960	0.6	8	1.7	24	0.6	8	4.2	59	-	-	7.1	100
1970	0.8	5	4.0	27	2.1	14	7.8	52	0.3	2	15.0	100
1975	0.9	5	2.2	12	2.7	15	7.4	41	4.8	27	18.0	100
1985	1.0	4	0.5	2	1.7	8	13.6	58	6.2	27	23.0	100
2000	1.0	3	0.32	1	1.6	4	21.7	58	13.0	34	37.6	100
2020	1.0	2	0	0	1.5	3	26.2	55	19.1	40	47.8	100

TABLE 3-5
RESIDENTIAL ENERGY DEMANDS BY FUEL FORM

Year	Primary Demand (Quadrillion BTUs)				Derived Demand Through Electricity (Quadrillion BTUs)					Total Demands (Quadrillion BTUs)	
	Solar	Gas	Coal	Oil	Gas	Coal	Oil	Hydro	Nuclear	Electric	Overall
1950	0.0	1.27	2.2	1.89	0.17	0.64	0.17	0.13	0.0	1.11	6.48
1960	0.0	3.19	1.16	3.56	0.38	0.92	0.13	0.13	0.0	1.56	9.47
1970	0.0	6.36	0.78	5.4	0.7	1.35	0.35	0.13	0.05	2.59	15.14
1980	0.1	7.3	0.0	6.4	0.41	2.84	0.67	0.29	1.59	5.8	19.6
1990	0.2	8.9	0.0	7.0	0.13	5.73	0.55	0.39	2.5	9.3	25.4
2000	1.7	8.44	0.0	7.5	0.09	7.06	0.47	0.28	3.85	11.75	29.5
2010	3.5	7.06	0.0	7.5	0.05	7.74	0.47	0.26	4.67	13.2	31.26
2020	5.5	5.95	0.0	7.5	0.0	7.5	0.45	0.22	5.38	13.55	32.5

TABLE 3-6
COMMERCIAL ENERGY DEMANDS BY FUEL FORM

Year	Primary Demand (Quadrillion Btus)				Derived Demand Through Electricity (Quadrillion Btus)					Total Demand (Quadrillion Btus)	
	Solar	Gas	Coal	Oil	Gas	Coal	Oil	Hydro	Nuclear	Electric	Overall
1950	0.0	0.92	1.72	1.51	0.19	0.76	0.19	0.16	0.0	1.32	5.46
1960	0.0	1.97	0.7	2.27	0.54	1.34	0.18	0.18	0.0	2.27	7.21
1970	0.0	3.56	0.32	3.09	1.28	2.46	0.24	0.24	0.09	4.73	11.7
1980	0.1	5.89	0.0	4.1	0.44	3.09	0.32	0.32	1.74	6.31	16.4
1990	0.2	7.52	0.0	5.8	0.12	5.6	0.35	0.35	2.24	8.8	22.32
2000	1.7	7.94	0.0	6.8	0.08	7.46	0.25	0.25	3.36	11.56	28.0
2010	3.5	8.26	0.0	6.8	0.04	9.11	0.22	0.22	3.96	13.74	32.3
2020	5.5	6.05	0.0	6.8	0.0	9.86	0.19	0.19	4.7	15.15	33.5

TABLE 3-7
INDUSTRIAL ENERGY DEMANDS BY FUEL FORM

Year	Primary Demand (Quadrillion Btus)				Derived Demand Through Electricity (Quadrillion Btus)					Total Demand (Quadrillion Btus)	
	Solar	Gas	Coal	Oil	Gas	Coal	Oil	Hydro	Nuclear	Electric	Overall
1950	0.0	3.58	5.8	2.04	0.23	.89	0.23	0.23	0.0	1.54	12.96
1960	0.0	5.21	5.63	2.65	0.78	1.91	0.27	0.26	0.0	3.2	16.69
1970	0.0	8.41	6.2	3.2	2.07	3.98	1.07	0.38	0.15	7.66	25.46
1980	0.1	9.0	9.73	5.33	0.55	3.84	0.96	0.39	2.16	7.84	32.00
1990	0.2	6.3	16.34	5.9	0.17	6.43	0.78	0.5	3.2	11.8	40.5
2000	1.7	6.0	19.6	6.8	0.14	7.0	0.7	0.42	5.74	14.0	48.1
2010	3.5	6.0	24.4	6.8	0.08	7.92	0.7	0.41	7.34	16.5	57.2
2020	5.5	4.0	27.7	6.8	0.0	8.28	0.66	0.36	8.64	18.0	62.0

TABLE 3-8
TRANSPORTATION ENERGY DEMANDS BY FUEL FORM

Year	Primary Demand (Quadrillion BTUs)			Derived Demand Through Electricity (Quadrillion BTUs)					Total Demands (Quadrillion BTUs)	
	Gas	Coal	Oil	Gas	Coal	Oil	Hydro	Nuclear	Electric	Overall
1950	0.16	1.64	7.4	-	0.02	-	-	0.0	0.03	9.24
1960	0.52	0.32	10.8	.01	0.03	-	-	0.0	0.04	11.7
1970	0.55	0.0	15.9	-	0.01	-	-	-	0.02	16.5
1980	0.95	0.0	21.0	-	0.03	-	-	0.01	0.05	22.0
1990	0.6	0.0	24.7	-	0.11	0.01	0.01	0.06	0.2	25.5
2000	0.3	0.0	22.3	-	0.2	0.02	0.01	0.16	0.4	23.0
2010	0.0	0.0	20.9	-	0.31	0.03	0.01	0.29	0.65	21.5
2020	0.0	0.0	20.0	0.0	0.46	0.04	0.02	0.48	1.0	21.0

Figure 3-12. Composite U.S. energy demand by fuel form.

TABLE 3-9
COMPOSITE U.S. ENERGY DEMAND BY FUEL FORM
[Quadrillion (10^{15}) Btu/yr]

Year	Hydro	Solar	Nuclear	Coal	Oil	Gas	Total
1950	0.47	0	0	13.68	13.4	6.5	34.1
1960	0.569	0	0	12.01	19.9	12.6	45.1
1970	0.749	0	0.3	15.3	29.6	22.9	68.8
1980	1.0	0.3	5.5	19.53	39.2	24.5	90.0
1990	1.25	0.6	8.0	34.2	45.23	23.7	112.9
2000	0.96	5.1	13.12	41.32	44.9	23.0	128.5
2010	0.914	10.5	16.26	49.5	43.6	21.5	142.3
2020	0.8	16.5	19.2	53.8	42.6	16.0	149.0

TABLE 3-10
U. S. DEMANDS ON FOSSIL FUEL RESOURCES
[Quadrillion (10¹⁵) Btu/yr]

Year	Coal	Oil	Gas	Total
1950	13.63	13.4	6.5	33.58
1960	12.01	19.9	12.6	44.51
1970	15.3	29.6	22.9	67.8
1980	19.53	39.2	24.5	83.23
1990	34.2	45.23	23.7	103.1
2000	41.32	44.9	44.9	109.2
2010	49.5	43.6	21.5	114.6
2020	53.8	42.6	16	112.4

3.3.2 Fossil Fuel Conversion Requirements

There are secondary fossil fuels available in abundance in the U.S. These secondary fuels (oil shale and tar sands), along with coal, can be converted into synthetic oil or gas. The probable need for these synthetics sources can be determined by comparing the demand projections for oil and gas with likely domestic supply projections for these fuel sources.

Supply and demand comparisons for domestic oil and gas are shown in Figures 3-13(a) and (b). Historically, excess demand has been filled by imports. In the future, however, because of economic and political limitations with regard to imports, synthetics and/or substitute energy sources will likely be employed to augment imported supplies. It is recognized that suggesting sources of oil and gas to satisfy demand more than 10 to 20 years in the future is, at best, based on judgment and "guesstimation," rather than trends.

3.3.3 External Facts Significant to Energy

The demand for energy, in general, is dependent upon many factors external to the availability of fuel sources and technology. A partial list of external influences would include:

- Environmental policy and associated constraints.
- Political climate relative to national energy policy and availability of imports.
- Economic conditions, projected growth rates, and productive mix of GNP world wide.
- Base population and projected population growth.
- Social trends.
- Business climate and availability of capital.

Figure 3-13. Supply and demand comparison for domestic production of (a) oil; and (b) gas [1,2,3,4,7,9,13].

It should be noted, however, that the role of energy in the lives of all U.S. citizens is so pervasive that a comprehensive list of all factors affecting demands for energy is beyond the scope of this study.

3.3.4 Credible Scenario for Fossil-Fuel Converted Energy Demand

In Section 3.3.2, a potential demand schedule for synthetic oil and gas was projected. The task in this section is to determine the most probable base fuel forms from which synthetics will be produced to meet these requirements.

Synthetic fuels as raw materials are relatively abundant. There are three basic raw materials: (1) coal, (2) oil shale, and (3) tar sands. Technologies to produce either oil or gas from these raw materials exist in various stages of development. The choice of the raw fuel source in a particular circumstance will likely depend on cost-benefit comparisons of the various synthetic technologies.

Obviously, hard dollar costs are a major consideration. All synthetic fuel plants will require enormous capital investments. Typically, a 100,000 bbl/day shale oil production facility may cost in excess of one billion dollars. For many synthetic fuel processes, many years of research and development have yet to be accomplished before commercially viable plants can be implemented. Demand for synthetic products from a particular conversion process will be sensitive to world-wide price competition. The capital, plant and equipment costs and the annual costs associated with operations and maintenance are the primary determinants in fixing price to the consumer. Table 3-11 gives a partial list of factors to be included in any comparison analysis.

TABLE 3-11
FACTORS AFFECTING COMPARISONS OF SYNTHETIC TECHNOLOGIES

1. The view point of the potential customer.
2. National energy policy.
3. Foreign energy policy and pricing of U.S. energy imports.
4. Differences in status of technology developments.
5. Lack of capacity to accurately predict resources.
6. Differences in cost accounting procedures.
7. Interchangeability of product fuel costs.
8. Local costs of environmental degradation.
9. Local economic benefits.
10. Alternative uses of capital.
11. Local attitudes.
12. Displaced industries.

Capital equipment charges are related to the net hydrogen/carbon ratio of the raw fuel used in the conversion process. This fact, coupled with the state of technology and resource assessability, seem to favor earlier development of synthetic liquids from oil shale and tar sands, and synthetic gas from coal.

The resulting projection of demand for synthetic oil and gas broken-down into primary demands by fuel form is shown in Table 3-12. These schedules were also reviewed in the context of existing projections.

3.4 Effects of Continued Reliance on Imported Oil

In 1977 oil imports in the United States were nearly 3.2 billion barrels, up sharply from the 1976 total of just under 2.7 billion barrels (14). This dependency on foreign reserves by the United States and the importing nations is having serious impact on the health and stability of the world economy. Effects have been felt in international trade, in the international monetary system, through domestic unemployment, and the resultant slowing in economic growth throughout much of the world.

A strong international trading system is essential to world economic prosperity and the resolution of economic problems faced by both the developed and developing nations. International trade is being hampered for several reasons: (1) the economic recovery in the industrialized nations has been and continues to be sluggish; (2) high domestic unemployment has brought pressure for job protection and trade restrictions; and (3) imbalance of payments between oil importers and exporters continues to grow (15).

The increase in the price of imported oil has resulted in wide fluctuations of world current account balances. The United States trade deficit for 1977 totalled 26.7 billion dollars (14). This was the result of importing 146 billion dollars worth of goods and products while exporting only 120.1 billion dollars worth (14). One third

TABLE 3-12
ESTIMATED DEMAND FOR SYNTHETIC FUELS
[Quadrillion (10^{15}) Btu/yr]

Year	Oil				Gas		Total
	Coal	Oil Shale	Tar Sands	Total	Coal	Total	
1980	-	-	-	-	.45	.45	.45
1990	0.5	1.0	0.1	1.7	1.1	1.1	2.8
2000	2.5	2.9	0.3	5.7	2.7	3.8	9.5
2010	5.7	4.6	1.1	11.4	5.8	5.9	17.3
2020	10.3	6.0	1.7	18.0	6.0	6.2	24.2

of the imports, 42.1 billion dollars, resulted from the purchase of foreign oil (14). This trade deficit has been the primary reason for the decline of the dollar on world money markets.

To counter growing imbalance of trade problems, consuming nations can either reduce consumption of oil, drain their reserve accounts, or increase their export trade. These options pose more severe problems for the third world nations. The international financial system has experienced an extraordinary expansion in borrowing and resulting accumulation of debt. The industrialized countries have been able to attract investment dollars from the oil producing nations and can more easily obtain credit. The developing nations, that do not export petroleum, had already accumulated substantial external debt to finance internal development prior to the 1973 oil-price hike. From 1973 to 1975 their total debt rose by almost 50% with the bulk of this increase resulting from the purchase of oil imports (16). The development of the Third World could slow substantially as: (a) they are forced into intensified world competition with the industrialized nations for scarce oil; and (b) thus grow increasingly more illiquid.

Many of these problems existing today may indeed be short-term. The oil producers cannot afford to abort the world economic recovery by hoarding their new found wealth or pricing themselves out of the market. On the longer term, these "petro" dollars will likely be redistributed to stimulate the world economy, and pricing will probably be consistent with the maintenance of a reasonably healthy market for their products. Problems resulting from heavy reliance on imported oil do exist now, however, and the duration of these effects cannot be predicted. Visibility for world economic projections is extremely limited. If current trends persist, a continued reliance on imported oil in the United States and abroad will result in rising unemployment, nagging inflation and vast international trade deficits (17). The developing nations will become so deeply indebted to the OPEC and Western Industrialized nations that their ability to achieve economic health may be inhibited for decades to come (17).

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CHAPTER 4

THE TECHNOLOGY AND DOE SUPPORT

Although turning coal into gas, or removing oil from rock, may seem like modern-day alchemy, synfuel technologies in fact have long, realistic histories. In the early part of the 1800's street lamps used gas from coal. In this century many American and European cities had "gasworks" that manufactured gas from coal for residential and industrial use. During World War II Germany, lacking domestic oil reserves, produced liquid fuel oil from coal suitable for military use. In Russia there have been commercial oil shale operations since the 1950's.

More recently, coal-to-gas conversion has been performed on a commercial scale in Europe and South Africa. South Africa, like Germany in World War II, was forced into its situation by strategic, geopolitical consideration. In Canada, a mostly private tar sands industry is thriving, and in the U.S. several Wellman-Galusha coal gasifiers, made by McDowell-Wellman Engineering Company at Cleveland, Ohio, are serving industrial plants.

Unfortunately, the success of commercial-sized operations elsewhere or of small-scale units in this country, does not mean that a full-blown, commercial industry, capable of meeting potential energy needs, will automatically become a reality in the U.S. Quite the contrary, the synthetic fuels industry in the U.S. faces several obstacles, environmental and economic. Even American commercial success earlier in the century does not necessarily bode well for a resurgence. The "coal gas" manufactured in the early 1900s was high in carbon monoxide content and would not be permitted in households today. And though cheap supplies of natural gas and oil, which caused the industry's original demise, are themselves reaching the end, enough uncertainty remains in the marketplace that private investors are reluctant to risk the large amounts of money, up to \$1 billion or more, required for each facility.^{1,2,3}

To assist the private sector, the U.S. Department of Energy (DOE) has been providing public monies for research, development and demonstration of synthetic fuels technology. In some cases the work is being accomplished at DOE laboratories under total DOE funding and control. In other instances it is a shared effort with private enterprise. A major effort involves an agreement with the American Gas Association (AGA) in which DOE provides two-thirds of the funding and AGA one-third to develop and encourage technology for producing synthetic gas. In some instances industry consortiums have been formed with DOE either as a member or providing partial or complete funding. DOE also interacts with other government agencies in this area.

DOE programs go through five phases:

- concept
- exploratory research
- process development unit (PDU)
- pilot facility (PF)
- demonstration facility (DF)

If significant progress has been made by private industry on its own, then DOE involvement may start with a later stage, such as the pilot or demonstration facility. Commercial operations are left to the private sector.

Each of the phases represents a successively larger project. Generally a PDU has a capacity of 5 to 10 tons per day (T/D) and under, pilot plant 10 to 1,000 T/D, a demonstration plant 1,000 to 10,000 T/D, and a commercial facility 10,000 T/D or 80 MMSCFD (million standard cubic feet per day) or more if it involves gas as opposed to solids or liquids. However, there are cases where these limits are exceeded and the definition for the facility depends more on the stage of technological development than the capacity.

This report, since it deals with environmental guidelines, is concerned chiefly with the pilot, demonstration and commercial phases. It is at those stages that a project becomes more than just a laboratory experiment, but an actual operating unit capable of generating significant amounts of pollution and of creating socioeconomic problems.

Currently, there are 62 projects funded totally or in part by DOE. Seventeen involve processes for converting coal into liquid fuel (liquefaction), 34 for the conversion of coal into gas (gasification), five for deriving oil from oil shale and one for extracting oil from tar sands. For the purposes of this report, the 62 projects include four programs for the direct combustion of coal for power generation. These four direct coal combustion projects are using more efficient technologies so that larger quantities of power are produced with each ton of coal burned.

Also included in the 62 is a magnetohydrodynamics (MHD) project. The major objective of MHD is the development of electrical, commercial-sized power generating plants, using coal as the primary fuel. The MHD process has potential to be more efficient and environmentally acceptable than other known processes if technical flaws can be eliminated. Like synthetics, MHD programs have many technical problems to work out before commercial development.

Indeed, most synthetics technologies are still in the early stages, at the PDU or pilot plant phase. Over the next several years, however, DOE plans an extensive construction program for demonstration facilities. Through 1982, eleven demonstration plants are scheduled for constructions. A complete listing of these and all other DOE projects, with development timetables, is provide in Table 4-1.

Because of the large number of processes in some of the technological categories, the following chapters are limited to discussions of the generic characteristics of the technologies and examples which illustrates the characteristics. While the data presented can be used to estimate the requirements, products, and impacts of specific processes, the actual values depend on the feedstock, process configuration and control equipment utilized, as well as any modifications which may result from continuing research.

In addition, the following processes with the potential for commercial development are discussed:

- Gasification
 - Lurgi
 - HYGAS
 - Synthane
 - Koppers-Totzek
 - Texaco Gasifier
 - Wellman-Galusha
 - Linked Vertical Wells (in-situ)
- Liquefaction
 - Exxon Donor Solvent
 - SRC (Solvent Refined Coal)
- Oil Shale
 - Modified In Situ
- Tar Sands
 - In Situ Reverse Combustion
- Direct Combustion
 - Fluidized Bed Boiler
- Magnetohydrodynamics (MHD)
 - Open Cycle Coal-Fired

The above processes were selected according to criteria that included length of time in development, successful operation in another country or of a pilot plant in the U.S., amount of monies allotted for research and development, evaluations of experts in the field, ability to process a variety of feedstocks, thermal efficiency, economic viability, general reliability and extent of potential environmental impacts. They are not, however, a comprehensive listing of all processes with potential for commercialization. Nor is their mention here meant to be an indication that these are the best processes. They are considered a good representative sampling, and as such provide the reader with a more precise understanding of how synfuels technology works.

The seven gasification processes include three for producing high Btu gas, two for producing a medium Btu product, one for low Btu gas, and one in-situ process. In-situ gasification and the differences between Btu levels are explained. It should be pointed out here that the gas product from all the gasification processes is technically capable of being upgraded to produce high Btu gas. However, economics dictate the ultimate end use of any gasification product.

It should also be pointed out that under oil shale, tar sands, direct combustion and MHD only one process for each technology has been selected for a full description. Other processes are under development, however, and the selection made here does not indicate that these are the best or the only ones.

Table 4-1

DOE-FUNDED PROGRAMS

The Department of Energy is supporting a significant number of energy projects. The information on the following pages was prepared in draft form by Cameron Engineers, Inc., and re-formatted by the Center for the Environment & Man.

**COAL LIQUEFACTION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY**

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. H-Coal	600 T/D 1860 BBL/D	1976-1978 Trenton, N.J.	1978-1981 Catletts- burg, Ky.			Developed by Hydrocarbon Research, Inc. (HRI). Ashland Synthetic Fuels Corp. built and operates pilot plant. Electric Power Research Institute, Ashland Oil, Standard-Ind., Conoco Coal Dev., Mobil, State of Kentucky, and DOE financed.
2. Synthoil	10 T/D 30 BBL/D	1977-1978 Pitts- burgh, Pa.	1978-1980 Pitts- burgh, Pa.			Developed, built and operated by Pittsburgh Energy Research Center (PERC).
3. Zinc Chloride Catalyst		1979-1980 Library, Pa.				Developed by Consolidation Coal Co., subsidiary of Conoco.
4. Disposal Catalyst Hydrogenation Program		1978 Pitts- burgh, Pa.				Developed by PERC.
5. Multistage Liquefaction Process		1978-1981 New Brunswick, N.J.	1981 New Brunswick, N.J.			Lummus developed, built, and operates pilot plant.
6. Solvent Refined Coal (SRC)	50 T/D		1976-1980			Developed by Spencer Chemicals Co. Pittsburgh & Midway Coal Mining Co. built & operates pilot plant.
7. Solvent Refined Coal (SRC)	6 T/D	1977-1980 Wilson- ville, Ala.				Developed by Spencer Chemicals Co. Southern Company Services built and operates P.D.U.
8. Solvent Extraction of Lignite		1976-1977 Univ. of N. Dakota				Developed by Univ. of North Dakota.
9. Co-Steam	240 lb/D	1978 Grand Forks, N. Dakota				Developed by PERC.
10. Donor Solvent	250 T/D	1977-1979 Baytown, Texas	1979 Baytown, Texas			Developed by Exxon Research and Engineering. Built and operates pilot plant.
11. Clean Metallurgical Coke/Liquids Process	0.5 T/D 1.5 BBL/D	1976-1979 Monroe- ville, Pa.				Developed by U.S. Steel.
12. Flash Liquefaction	1 T/Hr	1977-1978 Canoga Park, Calif.				Developed by Rocketdyne, Division of Rockwell International.
13. Entrained	3 T/D	1979-1980 LaVerne, Calif.				Developed by Occidental Research Corp.

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
14. Hydrocarbonization (Clean Coke Process)	10 lb/Hr	1977-1978 Oak Ridge, Ill.				Developed by U.S. Steel Corp.
15. Fluid Coke	0.35 T/D	1980-1980 Baytown, Texas				Developed by Exxon Research and Engineering.
16. Indirect Liquefaction (Fisher-Tropsch)		1978-1979				Developed by Mobil R&D.
17. COED (Char-Oil Energy Development)	36 T/D	1966-1970 Princeton, N.J.	1971-1976 Princeton, N.J.			Developed by AMC Corp. Built and operates pilot plant.

T/D = Tons per Day
 BBL/D = Billion Barrels per Day
 lb/D = Pounds per Day
 T/Hr = Tons per Hour
 lb/Hr = Pounds per Hour

LOW BTU COAL GASIFICATION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. Fixed Bed Gasification Stirred Process		1977-1982 Morgantown, W. Va.				Developed by Morgantown Energy Research Center (MSRC). Responsible for pilot plant.
2. Fixed Bed Gasification Slagging Process	25 T/D	1967 Grand Forks, N. Dakota	1978 Grand Forks, N. Dakota			Developed by Grand Forks Energy Research Center. Responsible for pilot plant.
3. Fluidized Bed Gasification 2-Stage Pressurized Process	15 T/D	1976-1979 Waltz Mill, Pa.				Developed by Westinghouse. Responsible for pilot plant.
4. Fluidized Bed Gasification 3-Stage Pressurized Process	1 T/D	1977-1978 Monroeville, Pa.				Developed by Bituminous Coal Research, Inc. Responsible for pilot plant.
5. Entrained Bed Gasification Atmospheric Process	120 T/D		1979-1980 Windsor, Conn.			Developed by Combustion Engineering. Responsible for pilot plant.
6. Combined Cycle Test Facility	480 T/D		1980-1983 Pekin, Ill.			Funded 30% U.S. Government, 70% Commonwealth Edison, Electric Power Research Inst. (EPRI), and Illinois.
7. Molten Salt Pressurized Process	24 T/D	1979-1980 Santa Susana, Calif.				Atomics International, subsidiary of Rockwell International, responsible for P.D.U. Technical support from Rockwell International.
8. Ash Agglomeration	6 T/D	1978-1979 Chicago, Ill.				Developed by Institute of Gas Technology.
9. Wellman-Galusha	Univ. of Minn.-75 T/D Pike County-1 MMSCFD			Univ. of Minn. & Pike County, Kentucky	Reading, Pa. (Past 35 years)	Planned Research for DOE by ACUREX, Univ. of Minnesota and Pike County, Kentucky. Six operational units at Glen-Gary Brick Co., Reading, Pa.
10. Winkler Process					16 Plants Worldwide	Davy Powergas, Inc., developing.
11. Low Btu Fuel Gas Project	500-3000 T/D			1982 Location Undetermined		Developed by Ebasco Services, W. R. Grace & Co., and the city of Memphis.

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
12. Coal Gasification Combined Cycle System for Electric Power	125-150 Btu/cf for 34 MW		Planned Sioux Falls, S. Dakota			Foster-Wheel Energy Corp. designing plant.
13. Woodall-Duckam Project	75 T/D			1980 Hitchens, Ky.		General Refractories Co. responsible.
14. Wellman Incandescent	75 T/D			1980 Perham, Minn.		Land O'Lakes Creamery use process designed by Applied Technology Corp.
15. Wellman-Galusha Single Stage	75 T/D			1980 Georgetown, Ky.		Irvin Industries will use.
16. Wellman-Galusha Single Stage	24 T/D		1978 York, Pa.			ACUREX-AEROTHERM Corp. responsible.

T/D = Tons per Day
 MMSCFD = Million Standard Cubic Feet per Day
 Btu/cf = Btu per Cubic Foot
 MW = Megawatts

HIGH BTU COAL GASIFICATION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. Hy-Gas	60 T/D 15 x 10 ⁶ SCFD	1965-1967 Chicago, Ill.	1970-1978 Chicago, Ill.			Developed by the Institute of Gas Technology (IGT), American Gas Association and the Office of Coal Research assisted with pilot plant.
2. CO ₂ Acceptor	40 T/D		1972-1978 Rapid City, S. Dakota			Developed by Consolidation Coal Co., and Conoco. Pilot plant built by Consolidation Coal Co.
3. Bi-Gas	120 T/D		1976-1978 Homer City, Pa.			Developed by Bituminous Coal Research, Inc. Pilot plant built by Phillips Petroleum.
4. Self Agglomerating Burner Process	25 T/D 10 x 10 ⁶ SCFD	1972 Columbus, Ohio	1978-1980			Developed by Battelle Memorial Institute and Union Carbide. Battelle Memorial built pilot plant.
5. Synthane Process			1977-1979 Pittsburgh, Pa.			Developed by Bureau of Mines at PERC. Lummus built pilot plant.
6. Hydrane	10-30 T/D	1981-1983 Pittsburgh, Pa.				PERC developed and built pilot plant.
7. Catalytic Gasification Process		1979-1980 Baytown, Texas	1982-1983 Undecided Location			EXXON developed and built pilot plant.
8. Steam Iron Process	11 MMSCFD		1977-1979 Chicago, Ill.			Developed by the Institute of Gas Technology. Pilot plant built by Institute of Gas Technology and Dravo.
9. Hydrocarbonization (Coalcon)	3901 T/D 2990 B/D 1088 MMSCFD-SPG 28 MMSCFD			1979-111.		DOE and Coalcon (Union Carbide) in design phase. If feasible, DOE may finance.
10. Koppers-Totzek	80-90 MMSCFD					Northern Illinois Gas Co., and the State of Illinois built demo plant. Commercial process since 1936.
11. Lurgi						SNG by Lurgi process planned by: El Paso Natural Gas, ANG Coal Gasification Co., Western Gasification, Panhandle Eastern, Northern Natural/CitiesService, Commonwealth Edison.

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
12. Slagging Lurgi	24 T/D		1977 Noble County, Ohio & Grand Forks, N. Dakota			DOE Grand Forks project. First design of 3-phase project by Conoco and awarded Noble County contract.
13. Koppers-Totzek					Planned (No date) Cedar Bayou, Texas	Air Products & Chemicals responsible for plant.
14. Pipeline Gas	2200 T/D			1982-1985 Perry County, Ill.		Developed by Illinois Coal Gasification Group.

T/D = Tons per Day
 SCFD = Standard Cubic Feet per Day
 MMSCFD = Million Standard Cubic Feet per Day
 SPG = Standard Pressure Gas

**MEDIUM BTU COAL GASIFICATION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY**

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. U-Gas Process	230 T/D			1981 Location Undetermined		Forster Wheeler, IGT, and Delta Refining co-participants for Memphis Light, Gas, and Water Co.
2. Texaco	1700 T/D			1981 Baskett, Ky.		W. R. Grace & Company will design, construct, and operate. Synthetic gas for ammonia.

**DIRECT COAL COMBUSTION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY**

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. Fluidized Bed Boiler	30 MW		1976-1980 Riversville, W. Va.			Developed by Pope, Evans and Robbins, Inc. Operations at Monongahela Power Plant, W. Va.
2. Pressurized Fluidized Bed Combined Cycle Pilot Plant	5 T/hr		1978 Woodbridge, N.J.			Developed, constructed and operated by Curtiss-Wright Corp.
3. PFB Combustor and Turbine Generator. Magnetohydrodynamics (MHD)		1974 Menlo Park, Calif.				Designed by Combustion Power Co.
4. Open Cycle, Coal-Fired MHD System				1981 Location Undetermined	1992	Funded by DOE, NASA, and National Science Foundation.

T/D = Tons per Day
T/Hr = Tons per Hour
MW = Megawatts

**IN SITU COAL GASIFICATION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY**

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. Linked Vertical Wells			1973-1978 Hanna, Wyoming			Developed by Laramie Energy Research Center (LERC). Technical support from Lawrence Livermore Laboratories and Morgantown Energy Research Center.
2. Packed Bed			1978-1982 Hoe Creek (Gillette Area) Wyoming			Developed by Laramie Energy Research Center.
3. Longwall Generator Process			1979 Pricetown, W. Va.			Developed by Morgantown Energy Research Center.
4. Steeply Dipping Bed Process						Contract to Gulf Oil Corp., in 1977. Planned for Walden, Colorado or Rawlins, Wyoming.

**IN SITU OIL SHALE LIQUEFACTION AND GASIFICATION PROJECTS
SUPPORTED BY THE DEPARTMENT OF ENERGY**

Process	Capacity	Process Development Unit	Pilot Facility	Demonstration Facility	Commercial Facility	Comments
1. True In Situ Recovery			1977 Rock Springs, Wyoming			Developed by Laramie Energy Research Center, Los Alamos Scientific Laboratory and Sandia Laboratories.
2. True In Situ Horizontal Recovery			1977-1978 Uinta Basin, Utah			1977 contract awarded to Geokinetics, Inc., and producing on small scale.
3. True In Situ Vertical Recovery			1977 Piceance Creek, Colo.			1977 contract awarded to Equity Oil. (Old project at same site.)
4. True In Situ Recovery			1977 Green River Basin, Wyo.			1977 contract awarded to Talley-Frac
5. Modified In Situ Recovery	2500 BBL/D		1978-1979 Piceance Creek, Colo.	1978-1979 Piceance Creek, Colo.		1977 contract awarded to Occidental Petroleum.

BBL/D = Billion Barrels per Day

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CHAPTER 5

COAL AND LIGNITE TO GAS

5.1 Brief technical description

Coal gasification processes have been in use and under continued development for several decades (about two centuries if the manufactured gas which antedated natural gas is included). Many processes have reached the pilot scale, and a few demonstration plants have been built.

There are three principal processes, depending on the state of the coal during gasification. In the fixed bed process, larger sizes of coal are fed to the top, to a stirred bed which operates much like a coal furnace, with a combustion zone well down in the bed just above the ash, which is removed from the bottom of the reactor. This arrangement is not practical for caking coals which exude a thick tar on initial heating. Unfortunately, most central and eastern U.S. coals are of the caking type.

A fluidized bed is the most popular configuration for processing U.S. coals because if caking coals are pretreated by partial combustion they can be processed. The fluidized bed acts much like quicksand (in which sand is fluidized by upflowing water) with coal being fluidized by rising reacting gases.

The entrained bed resembles utility combustion chambers, using a pulverized coal and high temperatures to react the coal very quickly in a rapidly rising gas stream within which the coal and its ash are entrained. Although the entrained bed works with all types of coal, it is not popular unless full gasification to H_2 and CO is desired because the high temperatures necessary for fast reaction destroy the partially converted product gases available from the fixed or fluidized beds.

Gasification plants can be categorized by their relationship to the generalized gasification flow sheet in Figure 5-1. A brief description of the basic process steps follows. Not all processes utilize all steps, and a few have different steps not noted in the generalized process. The most significant difference between processes is the nature of the gasifier — either fixed bed, fluidized bed or entrained bed.

Preparation. Most processes need coal of a specified size range. Crushing is the most important step in coal preparation, assuming that a clean coal is delivered to the process.

Pretreatment. Pretreatment is a partial oxidation of the surface of the coal to form an ash outer layer which keeps the coal particles from sticking together in further fluidized bed processing. Only the entrained bed gasifier can handle "caking" coals without pretreatment. It does this through exceptionally fast volatilization of very finely powdered coal suspended or entrained in a rapidly moving gas stream.

Figure 5-1. Generalized process flows for coal gasification.

Gasification. The endothermic reaction of steam with coal is called gasification:

The reaction takes place at 1500-3000 F, usually at elevated pressures. Oxygen is usually added, so that the modest heat required for gasification is provided by the familiar combustion process.

At lower temperatures (800-1500°F), methane and other hydrogen-bearing organic gases and tars are formed from some of the coal constituents on initial heating. Since they are directly useful as fuel, the size of subsequent hydrogenation units can be reduced by as much as a factor of two if these constituents are preserved. Such preservation is difficult, because complete gasification requires heating well beyond 800°F. A fixed bed gasifier can do this because the descending coal can be preheated at the top of the bed by hotter ascending gases to release its volatiles. The remaining char is then heated strongly enough to assure complete gasification as it nears the bottom of the bed where the combustion zone is located.

In a fluidized bed, gasifier coal particles are suspended in the gas stream but they are not so fine as to leave the bed with the gas. The fluidized coal mixes too much to maintain a large temperature difference between top and bottom, but relatively mild temperatures (1500°F) in the bed gasifiers can use pretreated caking coals while, in general, the fixed beds cannot.

Entrained gasification bed (which use a pulverized coal feed) react the coal quickly at very high temperatures (2000-3000°F) and so avoid all the problems of caking coals. Such high temperatures destroy methane and all organic compounds, however, and produce a very hot effluent gas consisting of hydrogen, CO, and residual water vapor, from which efficient heat recovery and utilization are mandatory if the process is to be efficient.

Quench. After gasification, the gases are quenched to about 300°F by contact with a water stream. The water removes most of the oils and tars, which can be skimmed and sold as by-products. The quench water becomes contaminated with phenols and cannot be released to the environment without thorough treatment. Ideally, all contaminated water is recycled to the process, or at least held in evaporation ponds so that the watershed is uncontaminated.

Shift reaction. When the product of the gasification is to be methane (CH_4) ("Substitute Natural Gas" (SNG)), the ratio of hydrogen to carbon monoxide in the gas entering the final reactor must be 3:1, whereas it is only 2:1 leaving the gasifier (Eq. 1). This requires additional hydrogen which is taken from steam by further reaction with half of the carbon monoxide to form carbon dioxide and hydrogen:

This reaction is called the "water gas shift" reaction. It takes place at about 750°F with an iron oxide catalyst and has been used for many years in conjunction with the synthesis of ammonia from hydrocarbons.

Desulfurization. In all the reaction steps so far discussed, hydrogen has been in excess and, therefore, sulfur in the coal feedstock will form hydrogen sulfide (H₂S) rather than sulfur dioxide (SO₂). This is an important point, since SO₂ is relatively difficult to remove from a gas stream while H₂S can be removed with ease. At the same point in the process, the ammonia formed by reaction of hydrogen with the nitrogen in the fuel can be removed easily and the production of nitrogen oxides thereby minimized when the gas is eventually burned. H₂S and ammonia are removed by absorption into a liquid. The H₂S is stripped from the liquid and converted to elemental sulfur or sulfuric acid. An SO₂ effluent is created during desulfurization. The amount of this pollutant reaching the atmosphere can be reduced by treatment in the same cleanup facilities used to desulfurize stack gas from coal combustion for process energy requirements.

Methanation. To produce SNG the carbon monoxide must be methanated or turned into methane by reaction with the hydrogen in the gas stream.

Eq. 3.

Methanation is an exothermic process which proceeds at high temperature (1000-2000°F) in the presence of a finely divided nickel catalyst. Steam is often added to the reactants of the cooled reaction products are recycled to slow the rate of reaction, so that control problems are minimized, for overheating can damage the catalyst. The reaction heat released in methanation should be utilized for it represents about 20 percent of the fuel value in the coal, but generally it is not used efficiently.

Hydrogen plant. If the processing conditions in the gasifier are such that the coal is not completely gasified, the solid waste product is referred to as "char." If the char is gasified separately to produce hydrogen to add to the gasifier, the methane content will be higher in the effluent gas than in a one-step gasifier. Char gasification proceeds much as ordinary gasification, although temperatures can be higher since hot effluent streams can be conveniently used to provide heat to the coal gasifier.

Oxygen plant. Process heat must be supplied to the gasification step of the reaction since the reaction is somewhat endothermic. This heat is generally provided by combustion of some of the coal. If air is used, the nitrogen content of the air used will appear in the product gas. The resultant lowered fuel content is especially undesirable if the gas is to be transported over long distances, as is customarily the case with SNG. SNG is, therefore, free of such diluents and is referred to as "high Btu" gas, since its fuel value of 700-1000 Btu/SCF approaches that of methane. This is accomplished by using oxygen plant, which uses well-proven technology utilizing an air feedstock and releases only air constituents as waste products.

"Low Btu" gas, having 100 to 300 Btu/SCF, is formed when the nitrogen from air is present in the combustion gas; it is never methanated. Such gas is usually used on-site for power generation or ordinary heating purposes, albeit less efficiently because of the high content of nitrogen. "Intermediate Btu" gas is the combination of carbon monoxide and methane produced after gasification with oxygen, quenching, and desulfurization. Its fuel value is in the 300 to 700 Btu/SCF range, but since it can be burned efficiently (although it cannot be transported economically over long distances), its production is logically to be combined with on-site utility power generation facilities. Low Btu gas may be generated for utility power generation with the internal gas turbine, however, since the temperature limitations of the turbine blades makes dilution of the gases necessary before combustion.

Only low Btu processes utilize entrained bed gasifiers, since the hot (2500°F - 3000°F) gases are difficult to deal with and the high temperatures destroy natural gases which are suitable constituents in SNG.

Low and intermediate Btu plants usually utilize the proven fixed bed or entrained bed gasifiers, because the fluidized beds offer little process advantage. The entrained bed is especially attractive since the high temperature outlet gas can be used directly by most power production processes, and the high conversion to CO and H_2 is very desirable if the product is used as a chemical feedstock.

5.1.1 In situ gasification

Gasification of coal in the ground, in situ, is an alternative which may alleviate water supply, environmental and safety problems. Recent experiments at Hanna, Wyoming, have verified the technical feasibility of underground coal gasification, producing a product with a heating value as high as 175 Btu/scf.

There are four techniques currently under investigation by DOE, each having an application to different types of coal beds. The Linked Vertical Wells (LVW) process is closest to commercialization. It is expected to apply to western subbituminous coal seams between 15 and 50 feet thick. Rows of wells are drilled into the seam. Air is injected into one row of wells causing partial combustion of the coal, while an adjacent row is used to collect product gases. The wells are linked by reverse combustion; that is, the combustion front is initiated at the production wells and travels in the direction opposite to flow of air. When the wells have been linked, the front is reversed, allowing additional product to be recovered from the remaining permeable char.

The Packed Bed (PB) process, suitable for western subbituminous coal seams of 50 to 500 foot thickness, uses chemical explosives to enhance the seam permeability. Collection wells are drilled to the bottom of the seam along its perimeter; injection wells are drilled in the interior. A steam-oxygen mixture is supplied which allows a medium Btu gas to be collected.

The Longwall Generator (LG) process is predominantly applicable to thin (less than 15 feet) eastern bituminous coal seams of low dip. Permeability is enhanced by drilling horizontal injection and production holes within the seam.

Seams which dip more than 45 degrees relative to the earth's surface are generally not exploitable by existing mining methods. The Steeply Dipping Bed (SDB) process differs from the previous three in that the flame front advance up the seam, rather

TABLE 5-1
REPRESENTATIVE ANALYSES OF COALS AND CHARs
(Percent of total weight)

	Illi- nois No. 6 coal	West- ern Ken- tucky coal	Wyo- ming subbi- tumi- nous coal	North Dakota lignite	Pitts- burgh seam coal
Coals:					
Moisture.....	8.3	4.3	18.1	20.6	2.5
Volatile matter...	37.5	34.6	31.9	32.9	30.9
Fixed carbon.....	43.0	44.5	32.0	38.2	51.5
Ash.....	11.2	16.6	18.0	8.3	15.1
Hydrogen.....	5.3	4.7	5.4	5.7	4.7
Oxygen.....	15.9	10.9	30.3	32.6	9.3
Carbon.....	63.0	62.7	45.2	51.5	68.4
Nitrogen.....	1.1	1.2	0.6	0.7	1.2
Sulfur.....	3.5	3.9	0.5	1.2	1.3
Chars (from above coals):					
Moisture.....	0.8	1.2	.5	1.2	1.4
Volatile matter...	4.0	4.8	5.1	10.0	1.6
Fixed carbon.....	69.9	63.3	38.1	50.2	69.3
Ash.....	25.3	30.7	56.3	38.6	27.7
Hydrogen.....	1.0	1.0	1.0	0.9	1.0
Oxygen.....	1.3	1.1	1.2	0.0	1.7
Carbon.....	70.4	64.5	40.6	58.9	68.9
Nitrogen.....	0.6	0.7	0.4	0.2	0.5
Sulfur.....	1.4	2.0	0.5	2.0	0.2

Source: BuMines Technical Progress Report TPR 76, *Analyses of Tars, Chars, Gases and Water Found in Effluents from the Synthane Process*, January 1974.

than between injection and production wells. Successful development of this process could increase domestic coal reserves by as much as 100 billion tons.

5.1.2 Char to Gas

Char gasification is an important part of several coal gasification and liquefaction processes. Char combustion is simple and presents no problems. Gasification is more difficult. Processing involves steam reforming in a fluidized bed at about 1650° F. The char is then reformed to carbon monoxide and hydrogen (synthesis gas) which is treated to remove H₂S. Process heat can be supplied by oxygen but the COGAS processes uses an undisclosed method which employs air without introducing combustion products into the product gas.

The emissions and general process scheme for char gasification are much like that for coal gasification, but the emissions depend on the sulfur in the incoming fuel. Table 5-1 gives compositions of char from the Synthane process with five different coals.

TABLE 5-2
COAL CHARACTERISTICS BY REGION

Region	Location	Type	Coal Bed	Moisture (%)	Volatiles (%)	Fixed Carbon (%)	Ash (%)	Sulfur (%)	Nitrogen (%)	Heating Value (btu/lb) ¹	Heating Value (btu/lb) ²
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	2.0	35.3	54.4	8.3	2.8	1.1	13,900	13,690
	Belmont Co., Ohio	Bituminous	Pittsburgh	3.8	40.3	43.2	8.7	3.9	1.1	13,500	12,940
	Jefferson Co., Ala.	Bituminous	Blue Creek	3.6	24.8	62.1	9.5	0.8	1.1	14,000	13,520
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	17.0	34.0	42.2	6.8	2.6	1.0	14,420	10,960
	Henderson Co., Ky.	Bituminous	No. 9	10.5	35.4	41.8	12.2	3.9	1.0	12,390	11,810
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	28.1	32.4	33.6	5.9	0.6	1.2	11,500	8,300
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	32.9	26.4	33.3	7.4	0.8	1.1	10,900	7,320
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	18.0	33.0	36.1	12.9	1.0	0.6	11,470	9,400

¹Moisture-free dry heating value.

²As received, wet heating value.

TABLE 5-3
COAL AND WATER CONSUMPTION FOR
HIGH BTU COAL GASIFICATION (a,b,c)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Water Consumption (million gallons/day)				
					Vaporized	Chemically Consumed	Total	Fixed Bed Actual Needed	Fluidized Bed Actual Needed
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	13,830	15.5	1.9	17.4	17.4	34.8
	Belmont Co., Ohio	Bituminous	Pittsburgh	14,640	15.5	1.6	17.1	17.1	34.2
	Jefferson Co., Ala.	Bituminous	Blue Creek	14,010	15.5	2.0	17.5	17.5	35.0
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	17,280	15.5	1.3	16.8	16.8	33.6
	Henderson Co., Ky.	Bituminous	No. 9	16,040	15.5	1.4	16.9	16.9	33.8
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	22,820	15.5	0.6	16.1	16.1	32.2
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	25,870	15.5	0.4	15.9	15.9	31.8
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	20,150	15.5	1.1	16.6	16.6	33.2

- a) Assumes a 66% overall thermal efficiency.
- b) Approximately 1000 Btu of waste heat are removed by each lb of water vaporized. Quantities can be reduced by use of air cooling.
- c) Water is consumed chemically by reaction with carbon, sulfur and nitrogen in the coal. An allowance has been made for the moisture content of the coal.

5.2 Quantity and type of primary source

For high Btu gasification processes, 250 million standard cubic feet (250 mmscf) of product gas is an accepted standard* for daily production, and process quantities will be in terms of such a unit synthetic plant. The amount of coal to feed a gas synthesis plant depends on the heating value of the coal and the efficiency of the process. The properties of representative coals are given in Table 5-2. Assuming an average thermal efficiency of 66 percent, Tables 5-3 and 5-4 give anticipated coal consumption for a unit plant, using the eight ranks of coal listed in Table 5-2.

5.3 Quantity and type of other resources used for energy conversion

Auxiliary energy

Ancillary fuel consumption (i.e., coal not gasified but burned directly for process energy) varies with the process configuration, but can be generically approximated as 15 percent of the total coal consumption for high Btu gasification and 12 percent for low Btu gasification.

TABLE 5-4
COAL AND WATER CONSUMPTION FOR LOW BTU COAL GASIFICATION (a,b,c)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Water Consumption (million gallons/day)				
					Vaporized	Chemically Consumed	Total	Fixed Bed Actual Needed	Fluidized Bed Actual Needed
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	10,740	5.3	1.9	7.2	7.2	14.4
	Belmont Co., Ohio	Bituminous	Pittsburgh	11,360	5.3	1.6	6.9	6.9	13.8
	Jefferson Co., Ala.	Bituminous	Blue Creek	10,880	5.3	2.0	7.3	7.3	14.6
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	13,420	5.3	1.4	6.7	6.7	13.4
	Henderson Co., Ky.	Bituminous	No. 9	12,450	5.3	1.5	6.8	6.8	13.6
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	17,720	5.3	0.9	6.2	6.2	12.4
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	20,090	5.3	0.8	6.1	6.1	12.2
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	15,640	5.3	1.2	6.5	6.5	13.0

- a) Assumes an 85% overall thermal efficiency.
- b) Approximately 1000 Btu of waste heat are removed by each lb of water vaporized. Quantities can be reduced by use of air cooling.
- c) Water is consumed chemically by reaction with carbon, sulfur and nitrogen in the coal. An allowance has been made for the moisture content of the coal.

Water

The water vaporized for cooling and chemically consumed by unit gasification plants are given in Tables 5-3 and 5-4. Cooling tower makeup is the principal use of water, since the actual gasification consumes only a small portion of the total. It is theoretically possible to do most of the cooling with air rather than water because, for the most part, cooling is near ambient temperatures is not required. However, it is unlikely that air cooling will soon be economic.

The cooling towers envisioned for gasification plants have unfortunate secondary problems. They are very large (up to 500 ft. tall, 250 ft. in diameter), and their sheer size makes them quite noticeable, if not unattractive, though some designs are considered to be aesthetically pleasing. When the weather is damp, plume clouds can form which may alter the local climate and produce ice or water fog at ground level.

5.4 Environmental control processes

Environmental control processes are used to minimize the quantities of particulates and sulfur oxides released to the atmosphere and to treat process and cooling water.

Particulate removal

Particulates are generated by coal combustion (not gasification) and can be reduced by the use of baghouses, cyclone separators, scrubbers and electrostatic precipitators. The applications of each are limited by the presence of certain materials (e.g., water or corrosives), temperatures, the desired removal efficiency and economic considerations.

Desulfurization

Much of the sulfur present in the coal feedstock is contained in the gases leaving the reactor in the form of hydrogen sulfide (H_2S). The gas is desulfurized by preferential absorption of H_2S into an aqueous solution (e.g., K_2CO_3 , CH_3OH , monoethanolamine). An acid gas stream is stripped from the liquid and fed to a sulfur recovery plant. These plants, which usually produce elemental sulfur or sulfuric acid, usually produce an SO_2 effluent which is combined with the combustion products of coal used for ancillary energy production.

The combined gases are treated in a scrubber, where 85 to 95 percent of the SO_2 is removed. Scrubbers can be classified as "throwaway" or "regenerative." In both types, SO_2 is absorbed by aqueous solution and reacts with the solute. In the throwaway systems, this produces a sludge requiring disposal, but regenerative systems produce a material from which the absorbent can be recovered. Some produce a saleable commodity, such as gypsum or sulfuric acid.

The commercially proven scrubbing systems include (1):

- Throwaway systems using lime or limestone.
- Double alkali: lime or limestone is used to regenerate sodium hydroxide ($NaOH$) or sodium sulfite (Na_2SO_3).
- Wellman-Lord: a concentrated SO_2 stream which can be converted to elemental sulfur or sulfuric acid is produced after absorption into Na_2SO_3 solution.

- Chiyoda: the gas is scrubbed by a dilute sulfuric acid solution, and gypsum is produced for sale or disposal.
- Magnesium oxide: MgO is regenerated and sulfuric acid is produced.

The overall reactions for systems where lime or limestone is the ultimate SO₂ acceptor is

The required quantities for these equimolar reactions are presented in Table 5-5 for the various coals. A desulfurization plant removal efficiency of 95 percent is assumed.

Water treatment

In any chemical plant, process and cooling water must be treated to prevent handling problems such as corrosion. The principle materials used for this purpose are sulfuric acid and sodium hydroxide (to control pH) and chlorine (to inhibit microbial growth).

5.5 Primary and secondary end products

The primary product of coal gasification is a combustible mixture of carbon monoxide, hydrogen and methane, all of which are gases. The product composition varies with the process but falls into one of three categories:

- Low Btu Gas (LBG) has a heating value of 100-300 Btu/scf (standard cubic foot) and is formed when air is used during gasification. There are no shift or methanation reactions involved.
- Intermediate Btu Gas (IBG), is similar to LBG except that oxygen is used instead of air during the gasification step. Because it contains no nitrogen, it has a higher heating value (300-700 Btu/scf) than LBG.
- Substitute Natural Gas (SNG), also referred to as "high Btu gas," is formed in processes which have shift and methanation steps. It has a high heating value (at least 700 Btu/scf) and can be used in place of natural gas.

During gasification, hydrogen sulfide (H₂S) and ammonia (NH₃) are released from the coal. It is possible to convert H₂S to elemental sulfur or sulfuric acid (H₂SO₄), both of which may be sold. The NH₃ can also be recovered and sold. Estimated quantities of by-product sulfur and ammonia are given in Tables 5-6 and 5-7. It should be pointed out, however, that not all coal gasification processes incorporate the equipment necessary to recover these materials.

TABLE 5-5
MATERIALS USED FOR STACK GAS DESULFURIZATION
IN A UNIT COAL GASIFICATION PLANT (a,b)
(Tons/day)

Region	Location	Type	Coal Bed	SNG		LBG	
				Lime	Limestone	Lime	Limestone
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	155	210	129	174
	Belmont Co., Ohio	Bituminous	Pittsburgh	223	301	185	251
	Jefferson Co., Ala.	Bituminous	Blue Creek	44	59	37	50
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	139	188	116	156
	Henderson Co., Ky.	Bituminous	No. 9	242	328	202	273
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	40	54	33	45
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	57	76	47	64
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	67	91	56	76

a) For lime and limestone "throwaway" scrubbing systems.

b) Assumes 95% removal of H₂S by the desulfurization plant and 90% removal efficiency for the scrubber.

TABLE 5-6
RESIDUALS AND BY-PRODUCTS FOR HIGH BTU COAL GASIFICATION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Auxil. Coal	Ammonia	Ash	Sulfur from Gasifiers	Sulfur from Flue Gas	Total Sulfur
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	13830	2080	110	1150	313	200	513
	Belmont Co., Ohio	Bituminous	Pittsburgh	14640	2200	116	1270	461	295	756
	Jefferson Co., Ala.	Bituminous	Blue Creek	14010	2100	111	1330	91	58	149
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	17280	2590	125	1180	363	232	595
	Henderson Co., Ky.	Bituminous	No. 9	16040	2410	116	1960	505	324	829
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	22810	3420	198	1350	111	71	181
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	25880	3880	206	1910	167	107	274
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	20150	3020	87	2600	163	104	267

- a) Assumes a 66% overall thermal efficiency for the gasification process and that 15% of the coal is burned directly for process energy.
- b) Assumes 70% of nitrogen in coal converted to ammonia (remainder in stack gas and ash).
- c) Assumes desulfurization plant converts 95% of H₂S to elemental sulfur.

TABLE 5-7
RESIDUALS AND BY-PRODUCTS FOR LOW BTU GASIFICATION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Auxil. Coal	Ammonia	Ash	Sulfur from Gasifiers	Sulfur from Flue Gas	Total Sulfur
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	10740	1290	88	890	252	152	403
	Belmont Co., Ohio	Bituminous	Pittsburgh	11360	1360	94	990	371	223	594
	Jefferson Co., Ala.	Bituminous	Blue Creek	10880	1310	90	1030	73	44	117
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	13420	1610	100	910	292	176	467
	Henderson Co., Ky.	Bituminous	No. 9	12450	1490	93	1520	406	245	651
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	17720	2130	159	1050	89	54	142
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	20090	2410	165	1490	134	81	215
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	15640	1880	70	2020	131	79	210

- a) Assumes an 85% overall thermal efficiency for the gasification process and that 12% of the coal is burned directly for process energy.
- b) Assumes 70% of nitrogen in coal converted to ammonia (remainder in stack gas and ash).
- c) Assumes desulfurization plant converts 95% of H_2S to elemental sulfur.

The products of several processes have been listed in the "Product(s)" column in Table 4-1.

5.6 Residuals; quantity, type, environmental significance, current legislation

Air Emissions

The gasification plant has no direct emissions to the air and is inherently low in pollution. Sulfur removal is, in fact, the most important function of a gasification plant. Sulfur is removed by absorption of gasified sulfur (as H_2S) into one of several aqueous liquids (K_2CO_3 , CH_3OH , etc.) after the gasified coal stream has been "shifted" and cooled. A solid high temperature adsorbent is also under study. Ammonia and carbon dioxide are also removed at this point, but ammonia is generally processed separately.

Recover H_2S is stripped from the solvent. The two-step Claus process is often used for sulfur recovery:

There is an SO_2 effluent from this process, but as much as 97% of the sulfur can be removed in a typical three reaction stage plant, and 99% if a fourth stage is added (2). The SO_2 -bearing waste stream is sent to a "stack gas" type desulfurizer because it is diluted with nitrogen remaining behind after use of air for formation of SO_2 . When the SO_2 in the stack gas is absorbed in liquid, it can be concentrated and used as a desulfurization plant feedstock.

The stack gas desulfurizers can remove about 85 to 95% of the remaining sulfur for an overall sulfur removal of up to 99.9%. The quantity of sulfur dioxide in the effluent, therefore, depends on the sulfur in the coal. Assuming a modes 95% sulfur removal in the desulfurization plant and a stack gas sulfur removal efficiency of 90% (99.5% removal efficiency), Tables 5-8 and 5-9 show the source and quantity of SO_2 emissions from unit gasification plants for the various coals. These tables assume that ancillary power has been generated directly from high sulfur coal feedstock in furnaces equipped with stack gas desulfurizers. Since these desulfurizers remove only 85 to 95% of the sulfur in the fuel, they are the source of the bulk of the SO_2 emissions. Therefore, if the plant were to use its own desulfurized fuel for ancillary purposes, the "total SO_2 " figures in the Tables could be reduced to about 20% of the totals shown. Such sulfur (and nitrogen)-free fuel would also reduce the nitrogen oxides emissions shown, which assume only a 25% reduction in NO_x due to pollution controls as is representative of current practice.

TABLE 5-8
AIR EMISSIONS FOR HIGH BTU COAL GASIFICATION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used. (tons/day)	Pri- mary SO ₂	Auxil. SO ₂	Total SO ₂	Particulates		NO _x	HC	CO	Alde- Hydes
								Min- ing	Pro- cess				
Appalachia	Monongalia Co., W.Va.	Bitumi- nous	Pitts- burgh	13,830	3.3	11.0	14.3	-	1.4	14	0.31	1.0	0.0052
	Belmont Co., Ohio	Bitumi- nous	Pitts- burgh	14,640	4.9	16.3	21.2	-	1.5	15	0.33	1.1	0.0055
	Jefferson Co., Ala.	Bitumi- nous	Blue Creek	14,010	1.0	3.2	4.2	-	1.6	14	0.32	1.0	0.0053
Eastern Interior	Fulton Co., Ill.	Bitumi- nous	No. 6	17,280	3.8	12.8	16.6	-	1.4	18	0.39	1.3	0.0065
	Henderson Co., Ky.	Bitumi- nous	No. 9	16,040	5.3	17.8	23.1	-	2.4	16	0.36	1.2	0.0060
Powder River	Campbell Co., Wyo.	Sub- bitumi- nous	Wyodak	22,820	1.2	3.9	5.1	0.7	1.6	23	0.51	1.7	0.0086
Fort Union	Mercer Co., N.D.	Lignite	Uncor- related	25,870	1.8	5.9	7.7	0.9	2.3	26	0.58	1.9	0.0097
Four Corners	San Juan Co., N.M.	Sub- bitumi- nous	Com- posite	20,150	1.7	5.7	7.4	2.6	3.1	20	0.45	1.5	0.0076

- a) Assumes a 66% overall thermal efficiency for the gasification process and that 15% of the coal is burned directly for process energy.
- b) EPA *Compilation of Air Pollutant Emission Factors* (AP-42) used to determine emissions from coal combustion, with control efficiencies of 99% for particulates, 90% for SO₂, and 25% for NO_x assumed.(3)
- c) Particulates resulting from coal mining obtained from *Synthetic Fuels Commercialization Program*.(4)

TABLE 5-9
AIR EMISSIONS FOR LOW BTU GASIFICATION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Primary SO ₂	Auxil. SO ₂	Total SO ₂	Particulates		NO _x	HC	CO	Alde-Hydes
								Min-ing	Pro-cess				
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	10,740	2.7	6.9	9.6	-	0.86	8.7	0.19	0.64	0.0032
	Belmont Co., Ohio	Bituminous	Pittsburgh	11,360	3.9	10.1	14.0	-	0.95	9.2	0.20	0.68	0.0034
	Jefferson Co., Ala.	Bituminous	Blue Creek	10,880	0.8	2.0	2.8	-	0.99	8.8	0.20	0.65	0.0033
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	13,420	3.1	8.0	11.0	-	0.88	10.9	0.24	0.81	0.0040
	Henderson Co., Ky.	Bituminous	No. 9	12,450	4.3	11.1	15.4	-	1.46	10.1	0.22	0.75	0.0037
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	17,720	0.9	2.4	3.4	0.6	1.00	14.4	0.32	1.06	0.0053
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	20,090	1.4	3.7	5.1	0.7	1.43	16.3	0.36	1.21	0.0060
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	15,640	1.4	3.6	4.9	2.0	1.94	12.7	0.28	0.94	0.0047

- a) Assumes an 85% overall thermal efficiency for the gasification process and that 12% of the coal is burned directly for process energy.
- b) EPA *Compilation of Air Pollutant Emission Factors* (AP-42) used to determine emissions from coal combustion, with control efficiencies of 99% for particulates, 90% for SO₂, and 25% for NO_x assumed.(3)
- c) Particulates resulting from coal mining obtained from *Synthetic Fuels Commercialization Program*.(4)

Particulates are also formed exclusively by auxiliary fuel combustion. Assumed controlled by 99% in Tables 5-8 and 5-9. They also could be eliminated entirely by use of desulfurized fuel, while the hydrocarbon, carbon monoxide and aldehyde emissions, all assumed uncontrolled, could be reduced considerably. The amount of trace pollutants (organics and trace elements) released by coal gasification and combustion has not yet been determined.

Water emissions

Water used within the process for the gas quench is highly polluted with ammonia, oils, and phenol and must be treated on site. The treated water is recycled to the process or mixed with cooling tower water so that remaining residuals will be air stripped, oxidized, or removed in the "blow-down" — the waste stream from the cooling towers which contains accumulated salts from the feed water. This waste stream is sent to lined evaporative ponds, ultimately producing a solid waste so that there is zero direct discharge into the watershed. When impounded with other wastes for evaporation, the volume of salts brought in by the water is small compared to the ash in the coal and is, therefore, not an important solid waste.

Solid wastes

Solid wastes and products are tabulated in Tables 5-6 and 5-7.

Sulfur. In most gasification processes, almost all the sulfur from the coal appears as elemental sulfur, which is a saleable commodity at present but will require disposal if the supply exceeds demand.

Depending on the stack gas purification process, some sulfur may be removed from stack gases as (saleable) sulfuric acid or as a gypsum sludge, the residual from wet limestone "throwaway" type SO_2 removal processes. More desirable processes (such as the Wellman-Lord) produce a concentrated SO_2 stream from which sulfuric acid or elemental sulfur can be recovered. The gypsum sludge will be of relatively low volume in comparison with the ash since only a small portion of the fuel is ever burned directly. Exceptions include the CO_2 Acceptor and Molten Iron processes which dispose of all the sulfur, using sludge-creating limestone.

Ash. A significant portion of the coal (6-13%) is ash. The environmental impacts of this residual include land required for disposal and possible (as yet undertermined) leaching of hazardous substances.

5.7 Process economics

The economics of gasification plants varies with the process configuration, type of coal, site and control equipment used. Estimated capital costs have risen at several times the rate of inflation (5,6,7,8,9,10). This is evidenced by two recent studies on the economics of the HYGAS, CO_2 Acceptor, BI-GAS and Synthane processes (all of which produce SNG) by the Bureau of Mines (11,7,8,9) and C. F. Braun and Co. (10), published in March and October of 1976, respectively. Comparable assumptions were made by each group in most cases. These included a 12 percent discounted cash flow rate, 100 percent owner equity, a three-year construction period and 20 years

operating life, a 90 percent stream factor and coal costs of \$7.00 and \$7.50/ton respectively. The range of results is summarized below (Bureau of Mines reports using July 1975 dollars, and Braun report using January 1976 dollars):

- Capital cost for plant with 250×10^9 Btu/day output.
 - Bureau of Mines: \$420 to \$643 million.
 - Braun: \$1066 to \$1399 million.
- Operation and maintenance:
 - Bureau of Mines: \$108 to \$159 million/year.
 - Braun: \$95 to \$135 million/year.
- Price of SNG:
 - Bureau of Mines: \$2.25 to \$3.43/million Btu.
 - Braun: \$3.91 to \$5.28/million Btu.

Both studies predicted the lowest cost for gas produced by the HYGAS process and the highest cost for SNG from the Synthane process.

No recent estimates were found in the course of this study for the cost of low or intermediate Btu gasification plants.

Infrastructure expansion

Advance planning and development of public infrastructure will mitigate adverse social effects of rapid growth. In some cases government and/or industry financing will be necessary to offset the associated costs, since the communities will experience tax revenue lags of 2 to 5 years following the expenditures.

The total costs are estimated at \$3000 per temporary resident and \$4500 per new permanent resident (an additional \$1500 will be required if the development occurs in new communities) based upon the following per capita assumptions (4):

- Water: \$625
 - \$45 for source development
 - \$130 for treatment facilities
 - \$450 for distribution and storage
- Sewage treatment: \$895
 - \$168 for treatment
 - \$720 for the collection system
 - \$7 for outflow lines
- Solid waste: \$15
- Fire service (12 pumpers and 5 ladder trucks within 5 miles for each 10,000 population): \$180
- Libraries: \$50

- Recreation: \$300
- Police and security: \$60
- Health (203 beds per 50,000 population at a cost of \$17,200,000): \$340
- Education: \$855
 - \$480 for elementary schools
 - \$355 for secondary schools
 - \$50 for vocational schools
- Community and social services: \$150
- Roads: \$400-\$1100 (\$1070 assumed for \$4500 total).

The total population associated with fossil fuel conversion plants will be about 2.67 times the total number of direct and indirect employees. This estimate is probably too large for the construction phase, since many construction workers will only be in the area temporarily and will not bring their families, and because there will be a time lag between the expansion of construction jobs and the development of service-related jobs. (4).

TABLE 5-10
INFRASTRUCTURE DEVELOPMENT COSTS ASSOCIATED
WITH UNIT COAL GASIFICATION PLANTS

	Peak Construction		Operation (a)	
	SNG	LBG	SNG	LBG
Total employment	8,400	1,680	5,183	2,607
Total population	22,430	4,486	13,840	6,961
Investment in existing communities (million dollars)	67.3	20.2	41.5	31.3
Additional investment for new communities (million dollars)	33.6	6.7	20.8	10.4

a) Assumes 960 surface miners for SNG and 750 for LBG.

TABLE 5-11
EMPLOYMENT FROM A UNIT COAL GASIFICATION PLANT (a,b)

	Primary		Secondary		Total	
	SNG	LBG	SNG	LBG	SNG	LBG
1. Construction						
1st year	252	68	454	122	706	190
2nd year	297	157	535	283	832	440
3rd year	1292	197	2326	355	3618	552
4th year	662	422	1192	760	1854	1182
Peak	3000	600	5400	1080	8400	1680
2. Operation	891	181	1604	326	2495	507
3. Mining						
• Appalachia						
- Monongalia Co., W.V.						
--Underground	2035	1580	3663	2844	5698	4424
--Surface	910	705	1638	1269	2548	1974
- Belmont Co., Ohio						
--Underground	2155	1670	3879	3006	6034	4676
--Surface	960	750	1728	1350	2698	2100
-Jefferson Co., Ala.						
--Underground	2060	1600	3708	2880	5768	4480
--Surface	920	715	1656	1287	2576	2002
• Eastern Interior						
- Fulton Co., Ill.	705	550	1269	990	1974	1540
- Henderson Co., Ky.	655	505	1179	909	1834	1414
• Powder River						
- Cambell Co., Wyo.	290	230	522	414	812	644
• Fort Union						
- Mercer Co., N.D.	400	305	720	549	1120	845
• Four Corners						
- San Juan, N.M.	330	260	594	468	924	728
Total During Operation			Minimum		3307	1151
			Maximum		8529	5183

(a) 328 operation days per year (90% stream factor).

(b) Based on the following productivity rates for miners (tons/person-day):

Appalachia		Eastern Interior	87
Underground	11.2	Powder River	100
Surface	29.7	Fort Union	100
		Four Corners	82

Source: *Synthetic Fuels Commercialization Program* [4].

TABLE 5-12
MAXIMUM ADDITIONAL DEMAND FOR COMMUNITY
SERVICES FOR A UNIT COAL GASIFICATION PLANT

Service Category	Peak Construction		Operation ^(a)	
	SNG	LBG	SNG	LBG
Doctors				
Primary	18	4	8	3
Specialty	15	3	6	2
Hospital Beds	90	18	38	14
Dentists	11	2	5	2
Law Officers	46	8	18	7
Police Cars	11	2	5	2
Firemen	23	4	9	3
Teachers				
K-6	616	123	260	95
7-9	308	62	130	47
10-12	308	62	130	47
Sanitary Landfill (acres)	89.7	17.9	37.8	13.8
Sewage Treatment (thousand gallons/day)	840	168	518	261
Water Treatment (thousand gallons/day)	1430	286	881.	443

a) Assumes 960 coal miners for SNG and 750 for LBG.

Based on assumptions in *Synthetic Fuels Commercialization Program* (4), which have been listed in the text.

Table 5-10 lists the infrastructure investment required for unit gasification plants in low population density areas:

5.8 Primary and secondary employment

Table 5-11 summarizes the number of workers needed to construct, operate and supply coal for a unit gasification plant. It is assumed that 1.8 secondary (service) jobs are created for each primary position (4).

5.9 Demand for community services

Table 5-12 lists the estimated service requirements resulting from a unit gasification plant. These figures represent the additional services required if all employees are new to the area. The total population is taken as 2.67 times the number of employees, and one school-age child is assumed for each 1.5 workers. The following standards were also assumed (4):

- 1 primary doctor/1222 population
- 1 specialist doctor/1508 population
- 4 hospital beds/1000 population
- 1 dentist/2000 population
- 1 law officer/500 population
- 1 police car/2000 population
- 1 fireman/1000 population
- 1 fireman/1000 population
- 1 teacher/18.2 school children
 - 50% of school children in grades K-6
 - 25% of school children in grades 7-9
 - 25% of school children in grades 10-12
- 4 acres of sanitary landfill/1000 population
- 1000 gallons of sewage treatment/person/day
- 170 gallons of water treatment/person/day

5.10 Reversible and irreversible commitment of resources

Resources which can be recovered at some time after commitment include:

- Land for the processing plant:
 - 400 acres for a unit SNG plant.
 - 235 acres for a unit LBG/IBG plant.
- Water supply: large quantities of water will be committed for the life of the plant.

The resources listed below could be irretrievably lost or substantially altered by the construction of a coal gasification plant:

- Capital.
- Land used for mining (see Table 5-13), roads, railroads, pipelines, transmission lines, reservoirs, community expansion and waste disposal could result in:
 - A decrease in soil productivity.
 - Loss of agricultural acreage.
 - Changes in topography.

Additional land devoted to agriculture will be lost by the sale of water rights in areas dependent on irrigation.

- Air quality.
- Water quality:
 - Aquifers could be interrupted during and altered as a result of mining.
 - Mining and processing could result in contamination of water supplies supplies by acid mine water and suspended and dissolved solids.
 - - Leaching from backfill deposits and solid waste disposal areas could introduce trace elements and minerals to water supplies.
- Natural habitat:
 - Despite reclamation efforts some mining areas may not be restorable to their original conditions, especially in the West. Revegetation may not be possible or new species may have to be introduced.
 - Restoration of a climax community could take as long as fifty years in the West. The amount, diversity, density and composition of both flora and fauna will be altered. Some species may be lost entirely to the region (endangered species in the area may become extinct).
- Additional community services will be required in most cases. The community structure and social order will be altered, except in urban areas.
- Only a fraction of one percent of the coal reserves would be lost to future generations.
- Construction materials, supplies and labor.
- Rural and unspoiled land; scenic landscapes.
- Sites of archeological historical or paleontological value may be disturbed or destroyed.

5.11 Difficulties in commercialization of the conversion processes

Above ground processes

TABLE 5-13
LAND REQUIRED FOR MINING TO SUPPORT A UNIT COAL GASIFICATION PLANT (a,b,c)
(acres/year)

Region	Location	Type	Coal Bed	Type of Mining	SNG	LBG
Appalachia	Monongalia Co., W.Va.	Bitumi- nous	Pitts- burgh	Underground Surface	75 295	55 220
	Belmont Co., Ohio	Bitumi- nous	Pitts- burgh	Underground Surface	110 425	85 330
	Jefferson Co., Ala.	Bitumi- nous	Blue Creek	Underground Surface	75 295	60 230
Eastern Interior	Fulton Co., Ill.	Bitumi- nous	No. 6	Surface	315	240
	Henderson Co., Ky.	Bitumi- nous	No. 9	Surface	470	360
Powder River	Campbell Co., Wyo.	Sub- bitumi- nous	Wyodak	Surface	55	45
Fort Union	Mercer Co., N.D.	Lignite	Uncor- related	Surface	170	150
Four Corners	San Juan Co., N.M.	Sub- bitumi- nous	Com- posite	Surface	245	190

(a) 328 Operating days a year (90% Stream Factor).

(b) Based on seam thickness

Appalachia	7 feet (Monongalia Co., W.Va.)
	5 feet (Belmont Co., Ohio)
	7 feet (Jefferson Co., Ohio)
Eastern Interior	8 feet (Fulton Co., Ill.)
	5 feet (Henderson Co., Ky.)
Powder River	60 feet (Campbell Co., Wyo.)
Fort Union	20 feet (Mercer Co., N.M.)
Four Corners	11.8 feet (San Juan Co., N.M.)

(c) All wastes and overburden are assumed to be returned to the mine site.

Source: *Synthetic Fuels Commercialization Program* [4].

Economic

Although some technical problems remain to be solved in most coal gasification processes, economics is the primary obstacle in the path toward commercialization.

- The gasification products may be marginally competitive, if at all, with conventional fuels.
- The large amount of capital necessary to construct a commercial plant.
- Regulations covering the incorporation to construct a commercial plant.
- Regulations covering the incorporation of higher costs in product price.
- LBG cannot be economically transported over large distances. However, it could be used as fuel for power generation or as a chemical feedstock or reducing gas by some chemical plants or metal refining industries.

With changes in regulatory policies and guarantees to lenders, some gasification processes could be viable between 1985 and 1990.

Technical

Technical problems can be classified into the following categories:

- Containment of high pressures in those processes where they occur, including the design, fabrication, transportation, erection and field stress relief of high pressure vessels and the reliability of valves and seals.
- Ash removal (plugging).
- Heat removal during methanation (SNG processes only).
- Useful life of catalyst during the methanation step in SNG processes.
- Low service life and inlet temperature of gas turbines in combined cycle LBG processes.
- Availability of water near western coal supplies.

In Situ

Initial research indicates favorable economics for in situ coal gasification. The following technical problems are as yet unresolved:

- Determination and control of subsidence.

- Control and capture of product.
- Variability of product composition.
- Contamination of aquifers.
- Directional control of fire fronts.

5.12 Current status and selected process descriptions

Commercially available coal gasification processes have been in use for over 50 years. The products of these processes have the present disadvantage of being economically uncompetitive compared to other fuels.

However, interest in gasified coal has recently been renewed by the desire to use the nation's abundant supply of coal without the adverse effects to health and the environment associated with direct burning. In 1978 \$51.2 million was budgeted by the federal government toward the development of new and improved processes for the production of high Btu gas and \$73.9 million toward those producing low Btu gas. The status of several processes at or nearing the commercial stage was given in Table 4-1.

In situ gasification currently in the fourth phase of a five phase project aimed at commercial development in 1985. The research is being carried out by the Laramie Energy Research Center of the Department of Energy, with an \$11.0 million budget for fiscal year 1978.

5.12.1 LURGI (HIGH BTU)

One of the most widely used processes for producing gas from coal is the Lurgi. Developed in Germany during World War II, it is currently used commercially in such countries as South Africa, Korea, Pakistan, India and Australia. In all, 19 commercial plants have been installed worldwide, none in the U.S. The economics in this country are still unfavorable unless efficiency of the Lurgi Process is improved, or the market situation changes. A number of American firms have announced plans to use the Lurgi Process in proposed SNG from coal plants. These include the El Paso Natural Gas project in New Mexico, ANG Coal Gasification Company's North Dakota project, and the Western Gasification Company (WESCO) project, also in New Mexico. None have yet come onstream.

DOE is funding a project in what is called slagging Lurgi. In this process the gasifier operates at higher temperatures than in the conventional "dry bottom" Lurgi and is therefore able to produce more gas for the same amount of coal used. The process gets its name from the slag that is produced as a residual instead of the usual dry ash.

DOE in May 1977 awarded Continental Oil Company, Stamford, Connecticut, the first phase contract of a three-phase project to design, construct, and operate a 3,800 T/D coal gasification facility producing 59 MM SCFD of SNG. The plant, to contain four slagging Lurgi gasifiers, is to be built in Noble County, Ohio. Ohio No. 9 coal has been selected for testing. The proposed process is based on work sponsored by an American consortium led by Continental and the British Gas Corp. Design phase contracts have been ratified and work is underway on both engineering and technical

support programs. East Ohio Gas will negotiate for purchase of gas which will be available in 1982. The estimated schedule is: design (22 months), construction (30 months), operation (42 months). Project costs are \$24 million for design and \$370 million for the total project. DOE will bear 100 percent of design costs.

The Lurgi gasifier is essentially a vertical kiln which is operated to react coal with steam and oxygen to produce a synthesis gas composed mostly of carbon monoxide, hydrogen and carbon dioxide. In order to produce pipeline quality gas for replacement of natural gas supplies the synthesis gas must be converted into methane.

It is high pressure gasifier, operating at 350 to 450 psig. The main gasifier shell is surrounded by a water jacket. Boiler feed water is circulated through the jacket to recover heat escaping from the gasifier shell. A coal lock hopper is mounted on top of the gasifier to feed the coal, while a motor-driven distributor is used to spread the incoming coal evenly over the coal bed.

Coal received from the stockpiles is crushed and screened. The coal is transported to the gasifier lock hopper by a system of belt conveyors. Fines generated during the crushing and screening must be removed to maintain bed porosity. They are available for use in the plant or for export. Steam and oxygen are introduced at the bottom of the gasifier to effect the coal gasification reactions. The steam and oxygen are distributed into the coal bed through the rotating grate.

An alternative to oxygen injection is air injection. When gasifying with air, nitrogen in the air accompanies and dilutes the final product. Because the nitrogen passes through the system without reacting, the result is a gasifier product with a lower Btu value than one produced by the oxygen-blown Lurgi.

The following paragraphs describe the slagging Lurgi Process as it is operated with oxygen. Most of the steps which purify the gas to produce a higher quality product (shift reaction, acid gas removal, methanation), are not used with air-blown gasifiers. With the latter, the gasifier product gas, after minimal cleanup, goes directly to a power or steam plant.

As the steam and oxygen pass upward, four different zones in the coal bed can be identified by the prevailing reactions and temperatures. They are, from bottom to top, carbon combustion, gasification, devolatilization, and drying. As the coal descends through the bed, some volatile matter in the coal is first removed, and the remaining carbon is then gasified and combusted. The ash is withdrawn from the bottom of the gasifier into the lock hopper and eventually sent to disposal. Excess steam is added to the ash layer just above the grate to prevent slagging of the ash.

Raw gas formed in the gasifier leaves from the top and flows through a scrubber cooler, where it is washed by circulating gas liquor. The gas then passed through a waste heat boiler, where it is cooled and low pressure steam is generated. Condensate formed is subcooled and sent to a tar/liquor separator. Gas leaving the waste heat boiler is further cooled by three water-cooled heat exchangers in series. A part of the condensate recovered from this cooling is sent to the tar/liquor separator, and the remainder is sent to an oil/liquor separator.

Tar and aqueous tar liquor are decanted in the tar/liquor separator. Similarly, tar oil and the aqueous oil liquor are decanted in the oil/liquor separator. The tar liquor and oil liquor are then combined and fed to a Phenosolvan unit and Chemie Linz-Lurgi (CLL) ammonia plant, where crude phenols and anhydrous ammonia are recovered.

Gas from the final cooler is desulfurized in an acid gas removal unit. By-product naphtha will be recovered from the condensate collected in a cooling step prior to acid gas removal.

The composition of the coal lock gas steam is the most important consideration. The composition of this gas will be determined by the mode of pressurizing the coal lock. Various operating procedures and sources of pressurizing could be used.

Prior to dumping the coal from the lock into the gasifier, the lock may be pressurized to the gasifier operating pressure with a stream of cooled raw gas or with a vent stream from an acid gas removal process. If the pressurizing gas is added continuously as the coal dumps into the gasifier, the gas remaining in the lock will have approximately the same composition as the pressurizing gas. If no gas is added as the coal is dumped, raw gas from the gasifier will back-flow into the lock as the coal falls into the gasifier, and gas remaining in the lock will be composed of pressurizing gas and raw gas from the gasifier.

If no pressurizing gas is used, the lock will fill with raw gas as the coal is dumped into the gasifier, and the gas remaining in the lock will be composed of raw gas.

For any of these cases, as raw gases pass countercurrently through the incoming coal and into the lock, some tar, oils, water and other constituents of the raw gas may condense or be adsorbed on the coal feed. In addition to the components in the raw gas and the lock-filling gases, the coal lock gas stream may also contain entrained coal fines.

In order to prevent the release of these contaminants to the atmosphere, this stream may be recycled to the raw gas stream, or it may be incinerated in a flare or boiler. If gaseous contaminants in this stream are relatively low in concentration, the stream may be passed through wet cyclones to remove particulates, and then vented to the atmosphere.

The gas which remains in the lock after depressurization will be displaced by the incoming coal charge. This gas can be controlled by the same methods described previously, but hoods and vent fans would be required to collect the gas.

As for liquid and solid effluents the slag slurry contains slag particles and slag quench water. The slag is composed of the mineral matter in the feed coal with approximately one percent unreacted carbon plus any ash-fluxing agent added to the feed coal. The exact composition of the slag is dependent on the composition of the feed coal and fluxing agents (if used) and the gasifier operating conditions. Suspended solids removal processes can be used to dewater the slag slurry. The recovered water could be recycled to the process condensate and the gas-quenching liquor. The dewatered slag or slag slurry is a solid waste product which requires ultimate disposal using known techniques.

The slag quench blowdown stream will be composed of the slag quench water which is removed from the slag lock prior to removal of the slag slurry. This stream will also contain condensate from the slag quench vent gas/liquor separator. The slag quench blowdown may contain any of the components present in the raw gas from the gasifier or in the quench water makeup. This stream may also contain entrained slag particles. The concentrations of contaminants in this stream will determine the control technology used. It may also be sent to disposal in evaporation ponds which will result in emissions to the atmosphere of all volatile components in the stream. This stream may also be treated by water pollution processes.

The composition of the slag quench vent gas stream will be determined by the mode of operation of the slag tap. If the slag is tapped intermittently by preventing slag flow with a slag burner, the slag quench vent stream will be created when slag is removed from the gasifier by swinging the slag burner aside and by opening the slag quench vent to create a positive pressure differential across the slag tap hole. For this case, the slag quench vent stream will be composed of combustion products, raw gas from the gasifier, steam, entrained slag particles, and any volatile components in the slag quench makeup water. This gas stream may first be passed through a cyclone to remove particulates, or it may be incinerated directly in a flare or boiler. If the slag is tapped continuously, a slag quench vent stream will not be present.

The process condensate and the gas quenching liquor will be composed of water plus the constituents of the raw gas which condense or dissolve in the quench water. The components most likely to be present in this stream are water, tar, tar oil, naphthas, crude phenols, coal fines and ash, ammonia, hydrogen sulfide, organic sulfur compounds, cyanide, thiocyanates, and trace elements. The amounts of these components will depend on the raw gas composition and gas quenching and cooling processes used. Water pollution control processes exist that can be used to remove these contaminants. (12,13,14,15,16,17,18)

5.12.2 HYGAS (HIGH BTU)

The HYGAS Process is being developed by the Institute of Gas Technology (IGT) as part of the joint program of DOE and AGA. DOE is providing two-thirds and AGA one third of the \$8 million contract funding. The HYGAS pilot plant is located in Chicago, Illinois. Evaluation date for the pilot facility is 1978. Design for a demonstration facility is underway by Procon, but there are no current plans for construction.

During 1975, 11 test runs were made in the pilot plant. The longest run was 363 hours, during which time 575 tons of lignite, a low grade coal, were fed to the gasifier. Based on the success of this test, authorization was given to begin testing with Illinois No. 6 bituminous coal.

Eleven pilot plant runs were made during the first half of 1976 using pretreated Illinois No. 6 bituminous coal. The last of the series, Test 54, began on June 30 and was voluntarily terminated on July 11 after successfully achieving all of the test objectives for establishing the technical feasibility of operating the HYGAS process with pretreated Illinois No. 6 bituminous coal.

Several steps are required to convert coal to high Btu gas with the HYGAS Process. Preparation involves crushing the coal to -8-mesh. Caking coal is pretreated in a

fluidized-bed at 660°F to 750°F and at atmospheric pressure to destroy caking tendencies and produce a free-flowing coal. Non-caking coal is fed indirectly into the slurry tank. The coal is mixed in this tank with an aromatic recycle oil to form a thick slurry and is pressurized to 1,000 psig. The slurry is then sprayed into the drying section of the gasifier.

In the drying section, oil is vaporized and removed, together with the hot gases passing upward from the first stage of the gasifier. Vaporized oil is recovered for reuse by quenching the effluent of the gasifier.

The dried coal drops into the first stage of the gasifier where it is heated rapidly by internally recycled hot char and hot reaction gases rising from the second-stage reactor. The relatively low temperature environment of the first stage provides for conversion of approximately 20 percent of the feed coal to methane (high quality gas). At the top of the first stage the diameter of the reactor increases rapidly thus reducing the velocity of the upward-flowing gases and solids. At these lower velocities, the partially spent char is separated from the gas and channeled downward. Part of this hot char is recycled to provide heat to the first stage, and the remainder is sent to the second stage, a high-temperature fluidized-bed reactor. An additional 25 percent of the raw coal feed is converted to methane in the hydrogen-rich environment of this stage.

The product gas, containing methane, carbon monoxide, carbon dioxide, hydrogen, and other raw gases, particulates, trace elements, and water and oil vapors, is quenched, purified, and passed to the methanator. In the methanator, the gas passes through a nickel catalyst at 800°F to 900°F and is transformed to methane, providing a pipeline quality gas with an average heating value of 1,000 Btu/SCF.

Environmental considerations will differ, depending on whether caking or non-caking coal is used. As noted, the use of caking coal requires pretreatment without which agglomeration in the fluid-bed occurs causing plugging. The environmental effects would be altered by such pretreatment. The IGT is currently extending the environmental assessment to cover the pretreatment step, but work is still preliminary. This report, therefore, addresses the use of non-caking coal.

During gasification the major effluent is the residual char that contains ash that enters with the coal feed. This char, containing 10 to 30 percent carbon, is quenched with water, depressured by lock hoppers, and sent to an ash-settling pond. Steam formed by this quenching operation may contain particulates and other contaminants; it can be returned to the process or collected for disposal.

Attrition of particles in the HYGAS reactor will generate fines that are carried up with the gas stream. These fines will be removed rather completely by the oil quench system, thus tending to build up in concentration in the recycle oil unless they are removed by agglomerating, filtration or other means. Similarly, volatile trace elements may accumulate in the recycle oil.

During quench and dust removal gas from the gasifier, together with slurry oil evaporated in the drying zone is quenched to 400°F by direct contact with recirculated oil, the heat being used to generate steam in waste heat boilers. Most of the oil vapor

in the entering gas is condensed and recycled to slurry preparation, while at the same time particulates and condensibles such as trace elements will be removed from the gas and will accumulate in the oil. While most of the oil is recycled, part of it must be withdrawn as product and can be expected to contain toxic elements such as arsenic, lead, and cadmium, as well as particulates, phenols, and sulfur and nitrogen compounds. Therefore the properties of this oil and its projected secondary use need further evaluation to define what treatment may be required to make it suitable for use as fuel or as a raw material for refining. (19)

During shift conversion some trace elements and coke are expected to be deposited on the shift catalyst. Reprocessing or proper disposal will need to be undertaken periodically.

When the gas liquor is depressured, gases are released that will be recovered or incinerated. In addition, sour water stripping produced by-product ammonia and hydrogen sulfide which can be sent to sulfur recovery.

If there is residual dust in the gas that leaves the oil quench system, it will require removal in the scrubber.

Phenols can be separated by extraction while sour water stripping will remove ammonia and hydrogen sulfide for recovery. Biological oxidation may then be used for further cleanup of waste water, followed by filtration or activated carbon processing as required.

During purification the bulk of contaminants remaining in the gas are removed. Major constituents are acid gases, hydrogen sulfide, and carbon dioxide, while minor contaminants include hydrogen cyanide, ammonia, light hydrocarbons, and naphtha. Acid gas treatment will remove all contaminants to a low level while providing a concentrated sulfur-containing stream to the sulfur plant with a carbon dioxide waste stream, which is pure enough to be vented directly to the air without further treatment.

The IGT design uses a system for acid gas treatment based on scrubbing with refrigerated methanol. The design shows 30 percent by volume concentration of sulfur compounds in the gas. This amount represents a desirably high concentration to allow efficient sulfur recovery.

The carbon dioxide rejected to the atmosphere is a very large stream, the tons per day exceeding the daily total of coal used by the plant. It will therefore be particularly free of contaminants in a concentrated form. Sulfur content at 300 ppm is moderate, amounting to less than 1 percent of the sulfur in the coal to gasification.

This content would appear acceptable in some cases depending on standards that apply for a specific location, at least if it were in a less objectionable form such as sulfur dioxide, rather than hydrogen sulfide.

The primary liquid effluent from acid gas treatment is a naphtha and oil mixture which is recovered from the gas by scrubbing with refrigerated methanol. This oil mixture is returned to the oil quench system and is eventually withdrawn as a by-product. As a result of the high cracking severity to which the oil has been exposed in the

gasification reactor, it will consist mainly of aromatics such as benzene and should be useful as a raw material for making chemicals or gasoline. Benzene is toxic so proper handling and storage precautions are needed.

There is also a small amount of water rejected from acid gas treatment, which can be combined with sour water from scrubbing for treatment.

There should be no significant solid effluents from acid gas treatment, since char and ash particles will be removed in the scrubber.

Methanation and drying are carried out in a closed system with no streams normally emitted to the atmosphere. Proper design and operation will control leaks from this system. Gas released when depressuring water, or when depressuring equipment for maintenance, will be collected and recovered or incinerated.

The methanation reaction produces a large amount of water which is condensed and used for makeup to steam boilers. The amount is large relative to the net waste water effluent and thus makes an important contribution in the overall water balance. It is a very clean condensate, free of sulfur and dissolved solids, so little or no treating is required. (12,13,14,14,16,19,20)

5.12.3 SYNTHANE (HIGH BTU)

The Synthane Process was developed by the U.S. Bureau of Mines at the Pittsburgh Energy Research Center, Bruceton, Pennsylvania. Development work started with scattered research in several areas. In 1961, work was started on methods of pretreating caking coals in fluidized beds. A preliminary design contract was awarded by M. W. Kellogg Company in August 1970 to determine if the data were sufficiently complete to proceed with design of the pilot plant. The contract was extended for additional gasifier tests and further evaluation of the Synthane project. Based on the results of the gasifier tests and evaluation, the U.S. Bureau of Mines concluded that the process was feasible and the design could begin.

In June of 1971, a contract was awarded to Lummus Company for obtaining process information and designing the pilot plant. The contract was modified several times to increase its scope to include rating and sizing heat exchangers, purchasing equipment, preparing a bid package, preparing a final report, additional engineering, inspecting, and control monitoring. Rust Engineering was awarded a contract to construct a pilot plant from design information obtained by Lummus.

Construction of the Synthane pilot plant was completed in March of 1975, and all areas and systems operations were transferred from the construction contractor to DOE. Through 1975 work concentrated on installation of auxiliary equipment and the repair and modification of the plant due to faulty equipment and design changes. During the first quarter of 1976 these repairs and changes were made and testing began.

Coal is crushed, dried, pressurized and transferred into the fluidized-bed pretreater by means of high pressure steam and oxygen. The coal overflows from the pretreater into the top of the fluidized-bed gasifier about 10 feet above the bed level, falls through

SYNTHANE PROCESS SCHEMATIC

hot gases rising from the fluidized-bed, and is devolatilized. This devolatilization contributes significantly to the methane yield. Steam and oxygen enter the gasifier just below the fluidizing gas distributor. The gasification reaction occurs within the fluidized-bed. Unreacted char flows downward into a bed fluidized with steam and water sprays and is removed through lock hoppers. This char can then be burned to produce process steam. This product gas, containing methane, hydrogen, carbon monoxide, carbon dioxide, ethane, and impurities, is passed through a venturi scrubber and a water scrubber to remove carryover ash, char, and tars.

The acid gases are adsorbed in a hot potassium carbonate scrubber. Carbon dioxide is reduced to 2 percent volume, and sulfur is reduced to 40 ppm. Regeneration of the potassium carbonate solution produces a hydrogen sulfide rich gas which is converted to elemental sulfur. The remaining traces of sulfur in the product gas are removed by passing the gas through activated charcoal. The purified gas must then be reacted to convert the hydrogen and carbon monoxide to methane.

Coal is charged to the gasifiers in the Synthane design through pressurized lock hoppers. In the design, each gasifier is provided with one lock hopper which discharges alternately into two feed hoppers from which coal is passed to the gasifier using a steam-oxygen mix as the transport medium. The gasifier charging sequence involves filling the vented lock hopper from pulverized coal storage bins, pressurizing the filled lock hopper. The pressurized lock hopper must be vented to essentially atmospheric when empty of coal in order to be refilled. The main volume of gas from the hopper could be contained in gas holders for recycle. However, various amounts of residual gas will remain and will be displaced to the atmosphere when fresh coal is fed into the hopper. The extent of the pollution problem depends on the pressurizing gas. Where this parameter has been determined in the design, the composition of the gases can be estimated. The lock hopper system for the Synthane pilot plant uses carbon dioxide as the pressurizing medium. This is vented directly to the atmosphere. Some contaminants may enter into the vent stream since the system will be heated and will cause some devolatilization of the coal.

The char formed in the char letdown system, in the gasifier, is discharged via the char letdown system down through the center of the distributor and into the char cooler attached to the gasifier. Spray water quenches the char, which is at 1,700°F and high pressure steam is produced. The steam is filtered for fines removal and is used in the shift converter. The char is discharged into lock hoppers and picked up by low pressure steam. In a commercial plant the char could be used to generate steam for the process or for the production of hydrogen. In the pilot plant, it will be used as landfill material. This is not expected to pose a problem, but a component analysis should be made and a leachability study conducted.

Another effluent problem involves spent catalyst used in the conversion process which will require periodic removal and replacement. The catalyst can be disposed of in a landfill or reprocessed for metals recovery. (12,13,14,15,20,21)

5.12.4 KOPPERS-TOTZEK (MEDIUM BTU)

The Koppers-Totzek Process was developed commercially by Friedrich Totzek of Essen and the Koppers Company, Inc. of Pittsburgh in 1949 following the successful operation of a 36 T/D coal gasifier for the U.S. Bureau of Mines in 1948.

Today, there are approximately 20 Koppers-Totzek plants commercially operating around the world, none of which are in the U.S. However, Air Products & Chemicals Company, Allentown, Pennsylvania, has been selected by DOE to negotiate for the design, construction, and operation of a facility for use in industrial processes. To be located at Cedar Bayou, Texas, the facility is expected to cost around \$100 million.

The Koppers-Totzek Process is appealing for several reasons. No by-products, which require additional processing, are produced. The absence of tars, oils, naphthas and phenols in the raw gas simplifies control technology requirements. The gasifier can be started in 30 minutes, can be shut down instantly, and can be restarted in 10 minutes.

However, for several other reasons the process may not be economical in the U.S. Operation with steam plus air dilutes the final product gas with nitrogen. Low operating pressure may be a disadvantage as costly compression is required for transmission or utilization of the gas in certain applications.

In the process, raw coal is dried and pulverized, and conveyed from storage to the gasifier service bins. Controls regulate feeding of coal to the bins. The coal is then mixed with oxygen and low-pressure steam, and delivered through a transfer pipe to the gasifier.

Coal is partially oxidized by oxygen in the presence of steam in the steel shell gasifier under slight pressure and high temperature (up to 3,500°F). Gasification of the coal is almost complete and instantaneous.

The raw gas passes through the waste heat boiler where high-pressure steam, up to 1,500 psig, is produced. After leaving the waste heat boiler, the gas at 350°F is cleaned and cooled in a scrubbing system. The system consists of two scrubbers, one for removing the largest particles, 95 percent of total, and another for removing most of the remaining, smaller particles. Following scrubbing, the gas is cooled with water to about 95°F. Electrostatic precipitators can be used for further cleaning. Several gasifiers can share common cleaning and cooling equipment.

The cool, clean gas leaving the gas cleaning system contains sulfur compounds which must be removed. The type of system chosen depends upon the end uses and desired pressure of the product gas. For low pressures and temperatures, up to 150 psig and 200°F, and industrial fuel gas applications, there are the hydrogen sulfide absorption processes using amine and carbonate solutions. At higher pressures, physical absorption processes can be used. The choice of the process is also dependent upon the desired purity of the product gas and the desired selectivity with respect to the concentrations of carbon dioxide and sulfides. The elemental sulfur recovered is a valuable by-product that can be sold.

Koppers-Totzek Gasifier

The nitrogen vent stream contains the nitrogen which is used to blanket the coal feed bins in order to prevent explosions of the fine coal particles. This stream will also contain entrained coal dust particules, which can be removed with filters, cyclones, or scrubbers prior to venting the nitrogen to the atmosphere.

The slag stream is composed of the larger slag particles formed in the gasifier which were heavy enough to fall to the bottom of the gasifier and into the slag quench tank. The slag particles will consist of mineral matter present in the feed coal with unreacted carbon. The slag may also contain any components present in the slag quench water or in the raw gas. The exact composition of the slag is dependent on the composition of the feed coal and the gasifier operating conditions. The slag is a solid waste product which requires ultimate disposal. In some instances, the granular slag may be a salable by-product. Solid waste treatment processes can be used for slag disposal.

The process condensate and gas-quenching liquor stream is composed of the raw gas-scrubbing liquor plus raw gas condensate from waste heat boilers and indirect gas coolers. The overflow from the slag quench tank is also added to this stream. The slag particles which are removed from the raw gas stream in the wash cooler are separated from the process condensate in a settling tank, but some slag particles may be carried along in the process condensate stream. The other components in this stream are the constituents of raw gas which condense or dissolve in the quench liquor. The components most likely to be present in this stream are water, particulates, ammonia, hydrogen sulfide, and trace elements. Water pollution control processes can be used to remove these contaminants.

The slag slurry stream contains the smaller slag particles which are carried out of the gasifier in the raw gas. The slag particles are removed from the product gas stream in the direct quench wash cooler. The slag slurry is separated from the process condensate and gas-quenching liquor in a settling tank. The slag particles in this stream have approximately the same composition as the slag previously described. The slag slurry may also contain any of the components present in the raw gas, the process condensate and gas-quenching liquor, or the slag quench overflow. Solid waste treatment processes can be used for slag slurry disposal. (12,13,14,15,16,22)

5.12.5 TEXACO GASIFIER (MEDIUM BTU)

From 1956 to 1958 Texaco tested a 100 T/D pilot facility for this process at Morgantown, West Virginia, using West Virginia coal. Texaco presently is operating a 15 T/D pilot facility at Montebello Research Laboratory in California to test all types of coals and chars.

W. R. Grace and Co., Ebasco Services and the State of Kentucky are planning to use the Texaco Gasifier process in a 1,700 T/D demonstration facility at Baskett, Kentucky, due to go on stream in 1981. Partial funding comes from DOE. This plant will produce 100 MM SCFD of medium Btu gas to be used in ammonia production.

The Texaco partial oxidation process gasifies coal under high pressure in an entrained bed by the injection of oxygen or air and steam with co-current gas/solid flow. The Texaco gasifier is a vertical, cylindrical pressure vessel. Coal is reacted

Texaco Gasifier

with steam and oxygen under slagging conditions in a partial oxidation chamber in the upper part of the gasifier. The resulting gases and molten slag particles flow downward through a water spray chamber and a slag quench bath. The temperature of the gas is so much reduced by the quenching process that it can be processed in unlined steel equipment.

Water is sprayed just below the partial oxidation chamber to cool the gas flowing downward. This results in large quantities of high pressure steam. The gas continues to be cooled in the slag quench bath as it leaves the gasifier.

Entrained slag is separated from the gas in the slag quench bath and removed through the slag pot. The product gas is further cleansed in a water scrubber which removes the residual slag particles as it leaves the gasifier. This product gas is a medium Btu synthesis gas. The slag and water mixture from the slag pot and water scrubber is collected and separated. The slag is disposed of, but the water is recycled to the slag pot or the water scrubber.

There is an alternative method for cooling the product gas. This method allows the gas to leave the gasifier unquenched at a high temperature. It then passes through a gas cooler where high pressure is generated. The decision as to which cooling method should be used depends upon the ultimate end use of the gas. The direct water quench process is used when the medium Btu gas will be used in the production of ammonia or hydrogen because the hot gas-steam mixture from the gasifier can be sent directly to the shift conversion process.

The Texaco gasifier requires pulverized coal in its process. Both lignite and bituminous coal have been satisfactorily tested. The feedstock is slurried with water as it is pumped to the gasifier. Because of the use of a water slurry, coal of any moisture content may be used in this process.

As for environmental considerations, the granular slag of this process contains less than 2 percent unconverted carbon and can be disposed of by landfill. The water recovered in the slag-water separator can either be recycled to form the coal slurry or it can be used to cool the gas in the gasifier or scrubber. Disposal is not normally required. (12,13,14,15,16,17)

5.12.6 WELLMAN-GALUSHA (LOW BTU)

The Wellman-Galusha Process, developed by McDowell Wellman Engineering Company of Cleveland, Ohio, has been in commercial use for over 35 years. Over 150 of the gasifiers have been installed worldwide for different industrial applications. Feedstocks such as anthracite, coke and bituminous coals have been used.

Currently, six units are operating in the U.S. at the Glen-Gery Brick Company, in Reading, Pennsylvania. The units can produce low-Btu gas for industrial use, using air instead of oxygen, or synthesis gas, using oxygen. The plants in use are small gasification units serving single large industrial plants. The gasifier could serve a complex of smaller plants requiring a high-Btu gas as a substitute natural gas in special cases.

In 1974, OCR awarded a \$95,000 contract to McDowell Wellman to determine the feasibility of constructing a fixed-bed gasifier for operation on caking coals. Under the contract, the firm supported its findings with a preliminary engineering design of the gasifier. It would operate at 300 psi on highly-caking coals with air to produce a low Btu product or oxygen moderated with either carbon dioxide or steam to produce a medium Btu product suitable for methane synthesis.

Recently, DOE and EPA have begun low level cooperation to evaluate small-sized gasifiers in DOE's Industrial Program. The gasifiers utilize up to 200 tons of coal per day. They will serve as a practical energy source, as a basis for obtaining data to make improvements in technology, and as a source of environmental information. The DOE phase of the program began in early 1976. The agency has signed agreements with:

- ACUREX Corporation, Aerotherm Division, Mountain View, California, to produce fuel for use in a brick kiln at the Glen-Gery Company plant in York, Pennsylvania.
- The University of Minnesota, Minneapolis, to produce boiler fuel for space heating of the Duluth campus;
- Pike County, Kentucky, to provide boiler fuel for central district heating and cooling of housing, a fire station, school, shopping center, and fuel for an industrial park near Pikeville.

There are actually two types of Wellman-Gulusha Gasifiers, the standard type and the agitated type. The rated capacity of an agitated gasifier is about 25 percent higher than that of the standard gasifier of the same size, and, unlike the standard gasifier, it can handle volatile caking bituminous coals. The agitated gasifier will be described in the following discussion.

The gasifier itself is water-jacketed. Water in the jacket completely surrounds the gasifier and also covers the top. The inner wall of the gasifier is steel plate and does not require a refractory lining. The agitator has a revolving horizontal arm which also spirals vertically below the surface of the coal bed to retard channeling and to maintain a uniform fuel bed. The agitator arm and its vertical drive shaft are made of water-cooled heavy steel tubing. The arm can be revolved at varying speeds, and its position within the fuel bed may be changed as desired for different feedstocks and operating rates. A revolving step-type grate is mounted eccentrically at the bottom of the gasifier on a center post. It distributes the air-steam blast into the coal bed and forces the ash formed into the ash bin.

Crushed coal is fed into the coal bin and flows into the feeding compartment by gravity. The feeding compartment continuously feeds the coal into the gasifier by gravity through the vertical feed pipes. Four slide valves control the flow of coal in and out of the feeding compartment. The upper valves are always open except when refilling. The continuous flow of coal into the gasifier is highly desirable because it assists in maintaining the coal bed and gas quality in a stabilized condition.

A fan supplies the air required for gasification. The air is passed over the top of the water in the jacket and picks up steam required for the blast. Saturation of

the blast is regulated by adjusting the jacket water temperature. Normally, the temperature is between 105°F and 180°F. A thermostat controls the water supply to the jacket. Blast mixtures of air and carbon dioxide, oxygen and carbon dioxide, or oxygen and steam can also be used.

The blast is introduced through the saturation pipe into the ash bin section underneath the grate. It is distributed through the grate into the coal bed, and is passed upward through the ash, combustion, and gasification zones. Combustion and gasification reactions occur, resulting in a gas containing mainly carbon monoxide, carbon dioxide, hydrogen, and nitrogen. The hot gas produced dries and preheats the incoming coal and then leaves the gasifier. Ash is withdrawn continuously through the eccentric grate, collected in the ash bin, and later sent to disposal.

Gas leaving the gasifier is passed through a cyclone where the heavy dust particles, mainly ash and char, are removed. The cyclone can also be flooded with water during a shutdown to an elevation a few inches above the internal gas-out-let, thus using the water seal to eliminate a mechanical valve.

The gas leaving the cyclone can be used hot if its sulfur content is acceptable. Otherwise, it can be scrubbed and cooled in a direct contact countercurrent water cooler and then sent for sulfur removal. If the gas contains tar, the tar may be separated from the cooled gas by mechanical or electrical precipitation methods. The resulting gas is a low Btu product gas. A medium Btu gas can be produced by using oxygen instead of air.

Cooling-water-overflow from the jacket and the agitator is not contaminated and can be cooled and recirculated. Blowdown from the gas cooler is sent to waste water treatment.

A small amount of tar is produced with bituminous coal and carried with the product gas. If it is removed from the gas before use, final disposition of this material would have to be ascertained for each installation.

Exit gasifier jacket water and cooling water for the agitator arm are relatively uncontaminated and can be recirculated after cooling. However, water discharged from the combination cyclone and water seal shutoff valve and the gas scrubber require treatment before disposal.

The ash produced from the Wellmna-Galuska Gasifier contains about 0.1 percent carbon and can be disposed of by landfill. (12,13,14,15,16,17)

5.12.7 IN SITU GASIFICATION - LINKED VERTICAL WELLS

In situ coal, or underground, coal gasification has considerable environmental advantages over mining and surface processes. In situ gasification needs less water and can use poor quality water. Safety problems are minimal compared with underground mining, as are environmental eyesores when compared to strip mining.

The major environmental questions with in situ gasification are possible surface and aquifer water contamination, safety during drilling operations and possible subsidence of the gasified area.

Linked Vertical Wells Process

The Linked Vertical (LVW) method of in situ gasification has been proven technically feasible at the Hanna, Wyoming test area by DOE's Laramie Energy Research Center (LERC). Development of LVW by LERC began in 1972.

In the Linked Vertical Wells process, wells are drilled into a coal seam to inject air and collect product gases. The LVW process uses reverse combustion to link the wells through the coal seam. This is followed by forward gasification of the coal between the linked wells. Two wells are drilled parallel to each other. High pressure air and propane are injected in the first well, and flow and burn in to the second through natural or artificially produced cracks and paths in the coal. When the burn reaches the second well, the combustion zone advances from the second well to the first against the gas flow, creating a hot char channel between them. During the process low Btu gas is produced and pumped to the surface.

Testing of the LVW at Hanna has been completed on three of the five phases scheduled. Phase IV of the testing is in progress at the Hanna fields. These are air acceptance tests with three wells in a line of 100 and 150 foot spacings, respectively. Air injection will be conducted in different wells to determine the maximum feasibility spacing up to 250 feet. Ignition of the coal near the bottom of the exposed coal bed in the production well is scheduled and may continue for up to six months. An estimated 28,000 tons of coal is expected to be consumed. This is twice the amount of coal consumed in all previous tests.

Phase V of the testing will examine the simultaneous operation of several test modules. This phase could produce 50 MM SCFD of low Btu gas at its peak. This massive scale test will provide the first extensive surface subsidence data.

Successful completion of this testing could make the LVW process commercial by 1985. (13,17,23)

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CHAPTER 6

COAL AND LIGNITE TO OIL

6.1 Brief technical description

There are four types of processes for making synthetic oils from coal. The Fischer Tropsch process makes straight chain hydrocarbons catalytically from carbon monoxide and hydrogen derived from coal in an intermediate-Btu gasification process. The overall efficiency is low, but the process is well proven, having been used during WW II in Germany; it is currently in use in South Africa.

Catalytic hydrogenation processes are high pressure hydrogenation processes which do not require gasification of the coal except for a small hydrogen plant. Further, they tend to produce aromatics which have much higher octane members and, therefore, need less processing for use as motor fuel. These processes are currently undergoing intensive research and development. Pressures on the order of 5,000 lb/in₂ and temperatures near 800°F are typical.

A major problem in catalytic hydrogenation is the separation of the solid ash from the solid catalyst for disposal of the ash. The hydrogen donor solvent process is very promising because the donor solvent is catalytically hydrogenated outside the reactor, and gives up its hydrogen to the coal more easily than does the gas-liquid mixture used in other processes.

All the catalytic hydrogenation processes use a similar flowsheet. They are very complex and are more properly described as a "refinery" because of the diversity of the products. A simplified diagram is shown in Figure 6-1. A fixed bed reactor is fed coal, recycled oil, and hydrogen which are all continuously recycled through the catalyst bed. A side stream is processed (by distillation) to remove the more volatile constituents which may themselves be further hydrogenated in a hydrocracker, i.e., a conventional oil refining process (not shown). A char is filtered from the distillation bottom product and sent to the hydrogen plant to produce hydrogen for the overall process.

Sulfur in the coal naturally appears as hydrogen sulfide, which is removed from the gas streams at a convenient place in a given process by the usual liquid absorption process for processing to elemental sulfur. The desulfurization process will provide 99.5 percent sulfur removal after removal of 90 percent of the sulfur dioxide in the plant tailgas.

The Solvent Refined Coal process is an example of a noncatalytic hydrogenation process. It produces a thick low-sulfur tar suitable for utility firing. The process conditions are relatively mild — 1000-2000 psi and 850°F. A recycle stream of lighter oils is stripped from the product liquid and mixed with coal. Some of the sulfur is left behind in the char, and the product may contain nearly one percent sulfur. The char is gasified with steam to provide hydrogen for the process.

Figure 6-1. Generalized process flows for coal liquefaction by catalytic hydrogenation.

Pyrolysis processes recover coal-based liquids from coal by heating without air. Even the most elaborate of these, the COED process, which uses four staged pyrolysis vessels operating at successively higher temperatures, leaves behind much char to be gasified conventionally or to be put to other uses.

Char to oil

Direct hydrogenation of char to oil is difficult. While it is unlikely that char will be economically processed to oil, the preferred process route would be gasification to synthesis gas (see Char to Gas) followed by Fisher-Tropsch synthesis because the hydrogen and organic structure of coal is not present in char.

6.2 Quantity and type of primary source

Coal gasification processes were characterized by their efficiency, water utilization, and proportion of fuel actually burned (auxiliary fuel). From this information, feedstocks, effluents and products were calculated, assuming constant characteristics for the necessary pollution controls.

A similar analysis holds for most liquefaction processes because the processes are similar in an overall sense. A unit liquefaction plant with a fuel output of 250×10^6 Btu daily will provide a standard basis for comparison with other coal conversion processes. This is equivalent to 45,000 barrels per day of synthetic liquids having a heating value of 5.6×10^6 Btu/bbl.

Coal requirements for Fischer-Tropsch synthesis, catalytic hydrogenation and the Solvent Refined Coal Process are presented in Tables 6-1 to 6-3.

6.3 Quantity and type of other resources used for energy conversion

Auxiliary Fuel

Auxiliary fuel may be provided from off-gas or less desirable (i.e., heavier) product streams rather than from burning raw coal. This will produce less particulates but about the same NO_x , hydrocarbon, and aldehyde emissions, and either more or less SO_2 depending on the residual sulfur in the stream burned. At the level of analysis used in this report, the auxiliary feedstock is best regarded as coal for calculational purposes.

Water Usage

Hydrogenation of coal to hydrocarbon liquids (having the general structure $(\text{CH}_2)_n$) chemically consumes less hydrogen and consequently less water is used than does hydrogenation to SNG ((CH_4)). The exact amount depends on the bound hydrogen already in the coal, but since the quantity is small in any case in comparison to cooling water volumes, it will be quantified simply as two moles of hydrogen per mole of fixed carbon in the coal (18 lb water for each 12 lb fixed carbon).

TABLE 6-1

COAL AND WATER CONSUMPTION FOR FISCHER-TROPSCH LIQUEFACTION (a,b,c)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Water Consumption (million gallons/day)		
					Vaporized	Chemically Consumed	Total
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	20,290	36.7	1.9	38.6
	Belmont Co., Ohio	Bituminous	Pittsburgh	21,470	36.7	1.5	38.2
	Jefferson Co., Ala.	Bituminous	Blue Creek	20,550	36.7	2.0	38.7
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	25,340	36.7	1.1	37.8
	Henderson Co., Ky.	Bituminous	No. 9	23,520	36.7	1.3	38.0
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	33,470	36.7	0.2	36.9
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	37,950	36.7	0	36.7
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	29,550	36.7	0.8	37.5

TABLE 6-2

COAL AND WATER CONSUMPTION FOR SOLVENT REFINED COAL (a,b,c)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Water Consumption (million gallons/day)		
					Vaporized	Chemically Consumed	Total
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	11,860	9.0	1.8	10.8
	Belmont Co., Ohio	Bituminous	Pittsburgh	12,550	9.0	1.6	10.6
	Jefferson Co., Ala.	Bituminous	Blue Creek	12,010	9.0	2.0	11.0
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	14,810	9.0	1.3	10.3
	Henderson Co., Ky.	Bituminous	No. 9	13,750	9.0	1.4	10.4
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	19,560	9.0	0.6	9.6
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	22,180	9.0	0.4	9.4
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	17,270	9.0	1.1	10.1

- a) Assumes 45 and 77% overall thermal efficiencies for Fischer-Tropsch and Solvent Refined Coal, respectively.
b) Approximately 1000 Btu of waste heat are removed by each lb of water vaporized. Quantities can be reduced by use of air cooling.
c) Water is consumed chemically by reaction with carbon, sulfur and nitrogen in the coal. An allowance has been made for the moisture content of the coal.

TABLE 6-3

COAL AND WATER CONSUMPTION FOR CATALYTIC HYDROGENATION LIQUEFACTION (a,b,c)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Water Consumption (million gallons/day)		
					Vaporized	Chemically Consumed	Total
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	12,680	11.7	1.9	13.6
	Belmont Co., Ohio	Bituminous	Pittsburgh	13,420	11.7	1.6	13.3
	Jefferson Co., Ala.	Bituminous	Blue Creek	12,840	11.7	2.0	13.7
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	15,840	11.7	1.2	12.9
	Henderson Co., Ky.	Bituminous	No. 9	14,700	11.7	1.4	13.1
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	20,920	11.7	0.5	12.2
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	23,720	11.7	0.3	12.0
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	18,470	11.7	1.0	12.7

- a) Assumes a 72% overall thermal efficiency.
- b) Approximately 1000 Btu of waste heat are removed by each lb of water vaporized. Quantities can be reduced by use of air cooling.
- c) Water is consumed chemically by reaction with carbon, sulfur and nitrogen in the coal. An allowance has been made for the moisture content of the coal.

Cooling water is again assumed to be provided to cooling towers, and the water "consumed" is calculated from the waste heat generated and the 1000 Btu/lb heat of vaporization of water (approximate).

6.4 Environmental control processes

The methods used to control air pollution and treat process and cooling water are similar to those described in Chapter 5, Section 4. Quantities of lime or limestone used for stack gas scrubbing are listed in Table 6-4.

6.5 Primary and secondary end products

The output of a unit liquefaction plant is taken as 45,000 barrels/day of synthetic liquids having an energy content of 5.6×10^6 Btu/bbl. These liquids can include (depending on the process) fuel oils, motor fuels, naphtha, benzene, alcohols distillates (groups of hydrocarbon compounds which boil at nearly the same temperature) and feedstocks

for various "petrochemical" processes. Other products include a variety of gases, char and "solvent refined coal" (the principal product of the SRC process). In addition, some processes incorporate steps to recover sulfur and/or ammonia. The products of the specific processes have been listed in Table 4-1.

6.6 Residuals: quantity, type, environmental significance, current legislation

Air Emissions

Process air emissions were calculated by the procedure given in Chapter 5, Section 6 and are presented in Tables 6-5 through 6-7. Also listed are particulate emissions for the supporting coal mining (relatively minor amounts of other air pollutants are released during mining operations.) The extent of trace element and organic compound emissions is not yet known. A significant reduction in particulate and sulfur oxides pollution could be obtained by using products of the process for ancillary energy production.

TABLE 6-4
MATERIALS USED FOR STACK GAS DESULFURIZATION
IN A UNIT COAL LIQUEFACTION PLANT (a,b)
(Tons/day)

Region	Location	Type	Coal Bed	Fischer-Tropsch		Solvent Refined Coal		Catalytic Hydrogenation	
				Lime	Limestone	Lime	Limestone	Lime	Limestone
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	224	303	131	177	146	198
	Belmont Co., Ohio	Bituminous	Pittsburgh	335	453	188	254	216	291
	Jefferson Co., Ala.	Bituminous	Blue Creek	64	86	37	50	41	55
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	201	271	117	158	129	174
	Henderson Co., Ky.	Bituminous	No. 9	350	473	205	277	225	304
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	58	78	34	46	37	50
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	82	110	48	64	53	71
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	97	131	57	77	62	84

- a) For lime and limestone "throwaway" scrubbing systems.
b) Assumes 95% removal of H_2S by the desulfurization plant and 90% removal efficiency for the scrubber.

TABLE 6-5

AIR EMISSIONS FOR FISHER-TROPSCH LIQUEFACTION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day.)	Primary SO ₂	Auxil. SO ₂	Total SO ₂	Particulates		NO _x	HC	CO	Alde-Hydes
								Min-ing	Pro-cess				
Appalachia	Monongalia Co., W.Va.	Bitumi-nous	Pitts-burgh	20,290	4.3	27.0	31.3	-	3.4	34	0.76	2.5	0.013
	Belmont Co., Ohio	Bitumi-nous	Pitts-burgh	21,470	6.3	39.8	46.1	-	3.7	36	0.80	2.7	0.013
	Jefferson Co., Ala.	Bitumi-nous	Blue Creek	20,550	1.2	7.8	9.0	-	3.9	35	0.77	2.6	0.013
Eastern Interior	Fulton Co., Ill.	Bitumi-nous	No. 6	25,340	4.9	31.3	36.2	-	3.5	43	0.95	3.2	0.016
	Henderson Co., Ky.	Bitumi-nous	No. 9	23,520	6.9	43.6	50.5	-	5.7	40	0.88	2.9	0.015
Powder River	Campbell Co., Wyo.	Sub-bitumi-nous	Wyodak	33,470	1.5	9.5	11.0	1.2	4.0	57	1.26	4.2	0.021
Fort Union	Mercer Co., N.D.	Lignite	Uncor-related	37,950	2.3	14.4	16.7	1.5	5.6	64	1.42	4.7	0.024
Four Corners	San Juan Co., N.M.	Sub-bitumi-nous	Com-posite	29,550	2.2	14.0	16.2	4.3	7.6	50	1.11	3.7	0.019

- a) Assumes a 45% overall thermal efficiency for the liquefaction process and that 25% of the coal is burned directly for process energy.
- b) EPA *Compilation of Air Pollutant Emission Factors* (AP-42) used to determine emissions from coal combustion, with control efficiencies of 99% for particulates, 90% for SO₂, and 25% for NO_x assumed.
- c) Particulates resulting from coal mining obtained from *Synthetic Fuels Commercialization Program*. (1)

TABLE 6-6
AIR EMISSIONS FOR SOLVENT REFINED COAL (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Primary SO ₂	Auxil. SO ₂	Total SO ₂	Particulates		NO _x	HC	CO	Alde-Hydes
								Min-ing	Pro-cess				
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	11,860	3.2	1.9	5.1	-	0.24	2.4	0.05	0.18	0.009
	Belmont Co., Ohio	Bituminous	Pittsburgh	12,550	4.80	2.8	7.5	-	0.26	2.5	0.06	0.19	0.009
	Jefferson Co., Ala.	Bituminous	Blue Creek	12,010	0.9	0.6	1.5	-	0.27	2.4	0.05	0.18	0.009
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	14,810	3.7	2.2	5.9	-	0.24	3.0	0.07	0.22	0.0011
	Henderson Co., Ky.	Bituminous	No. 9	13,750	5.2	3.1	8.3	-	0.40	2.8	0.06	0.21	0.0010
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	19,560	1.1	0.7	1.8	0.4	0.28	4.0	0.09	0.29	0.0015
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	22,180	1.7	1.0	2.7	0.5	0.39	4.5	0.10	0.33	0.0017
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	17,270	1.7	1.0	2.7	1.6	0.53	3.5	0.08	0.26	0.0013

- a) Assumes a 77% overall thermal efficiency for the liquefaction process and that 3% of the coal is burned directly for process energy.
- b) EPA *Compilation of Air Pollutant Emission Factors* (AP-42) used to determine emissions from coal combustion, with control efficiencies of 99% for particulates, 90% for SO₂, and 25% for NO_x assumed.
- c) Particulates resulting from coal mining obtained from *Synthetic Fuels Commercialization Program*.⁽¹⁾

TABLE 6-7

AIR EMISSIONS FOR CATALYTIC HYDROGENATION LIQUEFACTION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Primary SO ₂	Auxil. SO ₂	Total SO ₂	Particulates		NO _x	HC	CO	Alde-Hydes
								Min-ing	Pro-cess				
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	12,680	3.4	3.4	6.8	-	0.42	4.3	0.10	0.32	0.0016
	Belmont Co., Ohio	Bituminous	Pittsburgh	13,420	5.0	5.0	9.9	-	0.47	4.5	0.10	0.34	0.0017
	Jefferson Co., Ala.	Bituminous	Blue Creek	12,840	1.0	1.0	2.0	-	0.49	4.3	0.10	0.32	0.0016
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	15,840	3.9	3.9	7.8	-	0.43	5.4	0.12	0.40	0.0020
	Henderson Co., Ky.	Bituminous	No. 9	14,700	5.5	5.5	11.0	-	0.72	5.0	0.11	0.37	0.0018
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	20,920	1.2	1.2	2.4	0.8	0.49	7.1	0.16	0.52	0.0026
Fort Union	Mercer Co., N.D.	Lignite	Uncor-related	23,720	1.8	1.8	3.6	1.0	0.70	8.0	0.18	0.59	0.0030
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	18,470	1.8	1.8	3.5	2.7	0.95	6.2	0.14	0.46	0.0023

- a) Assumes a 72% overall thermal efficiency for the liquefaction process and that 5% of the coal is burned directly for process energy.
- b) EPA *Compilation of Air Pollutant Emission Factors* (AP-42) used to determine emissions from coal combustion, with control efficiencies of 99% for particulates, 90% for SO₂, and 25% for NO_x assumed.
- c) Particulates resulting from coal mining obtained from *Synthetic Fuels Commercialization Program*. (1)

Water Emissions

As was done for coal gasification, it is assumed that all process water streams are used as cooling water make-up and that all blow-down is sent to lined evaporative ponds. Thus, water contamination from such a plant is limited to potential run-off from mines and solid waste disposal areas.

Solid Wastes

Solid wastes and products from liquefaction processes are tabulated in Tables 6-8 through 6-10. An additional 72 to 395 tons/day of waste resulting from supportive coal mining will require disposal. Sulfur is currently a saleable commodity, but will be disposed if the supply exceeds demand.

6.7 Process economics

Recent analyses of two coal liquefaction processes approaching the demonstration stage, H-Coal and Solvent Refined Coal, were performed by the Bureau of Mines (2,3). For a plant producing 50,000 barrels per day, operating 330 days per year, using Wyodak coal at \$7.00 per ton, with a 20 percent contingency and 8 percent working capital, the following results were obtained (in July 1975 dollars):

- Capital costs for 50,000 bbl/day plant:
 - H-Coal: \$889 million.
 - SRC: \$711 million.
- Operation and maintenance:
 - H-Coal: \$220 million/year.
 - SRC: \$182 million/year.
- Product price:
 - H-Coal \$3.14, 3.58, and \$4.40 per million Btu for discounted cash flow (DCF) rates of 12, 15, and 20 percent, respectively.
 - SRC: \$2.82, \$3.21 and \$3.93 for 12, 15 and 20 percent DCF rates, respectively.

Infrastructure expansion

Infrastructure investments for unit coal liquefaction plants in sparsely populated areas are listed in Table 6-11. These are based on the employment estimates in Table 6-12 and on the assumptions in Chapter 5, Section 7.

6.8 Primary and secondary employment

Table 3-12 summarizes the number of workers needed to construct, operate and supply coal for a unit liquefaction plant. It is assumed that 1.8 secondary (service) jobs are created for each primary position. (1).

TABLE 6-8

RESIDUALS AND BY-PRODUCTS FOR FISHER-TROPSCH LIQUEFACTION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Auxil. Coal	Ammonia	Ash	Sulfur from Liquefaction	Sulfur from Flue Gas	Total Sulfur
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	20290	5010	142	1680	401	320	724
	Belmont Co., Ohio	Bituminous	Pittsburgh	21470	5360	151	1870	597	471	1067
	Jefferson Co., Ala.	Bituminous	Blue Creek	20550	5180	144	1950	117	92	210
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	25340	6340	162	1720	470	308	840
	Henderson Co., Ky.	Bituminous	No. 9	23520	5880	150	2670	654	516	1169
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	33470	8370	267	1970	143	113	256
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	37950	9490	266	2810	216	171	387
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	29550	7390	113	3810	211	166	377

- a) Assumes a 45% overall thermal efficiency for the liquefaction process and that 25% of the coal is burned directly for process energy.
- b) Assumes 70% of nitrogen in coal converted to ammonia (remainder in stack gas and ash).
- c) Assumes desulfurization plant converts 95% of H_2S to elemental sulfur.

TABLE 6-9
RESIDUALS AND BY-PRODUCTS FOR SOLVENT REFINED COAL(a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Auxil. Coal	Ammonia	Ash	Sulfur from Liquefaction	Sulfur from Flue Gas	Total Sulfur
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	11860	360	108	980	306	154	460
	Belmont Co., Ohio	Bituminous	Pittsburgh	12550	380	114	1090	451	227	678
	Jefferson Co., Ala.	Bituminous	Blue Creek	12010	360	109	1140	89	45	133
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	14810	440	122	1010	355	178	533
	Henderson Co., Ky.	Bituminous	No. 9	13750	410	113	1680	494	248	742
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	19560	590	194	1150	108	54	163
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	22180	670	201	1640	164	82	246
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	17270	520	85	2230	159	80	239

- a) Assumes a 77% overall thermal efficiency for the liquefaction process and that 3% of the coal is burned directly for process energy.
- b) Assumes 70% of nitrogen in coal converted to ammonia (remainder in stack gas and ash).
- c) Assumes desulfurization plant converts 95% of H_2S to elemental sulfur.

TABLE 6-10

RESIDUALS AND BY-PRODUCTS FOR CATALYTIC HYDROGENATION LIQUEFACTION (a,b,c)
(tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Auxil. Coal	Ammonia	Ash	Sulfur from Liquefaction	Sulfur from Flue Gas	Total Sulfur
Appalachia	Monongalia Co., W.V.	Bituminous	Pittsburgh	12680	630	113	1050	324	170	488
	Belmont Co., Ohio	Bituminous	Pittsburgh	13420	670	119	1170	472	247	719
	Jefferson Co., Ala.	Bituminous	Blue Creek	12840	640	114	1220	93	49	141
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	15340	790	128	1080	372	195	566
	Henderson Co., Ky.	Bituminous	No. 9	14700	740	119	1790	517	271	788
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	20920	1050	203	1230	113	59	173
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	23720	1190	211	1760	171	90	261
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	18470	920	90	2380	167	87	254

- a) Assumes a 72% overall thermal efficiency for the liquefaction process and that 5% of the coal is burned directly for process energy.
- b) Assumes 70% of nitrogen in coal converted to ammonia (remainder in stack gas and ash).
- c) Assumes desulfurization plant converts 95% of H_2S to elemental sulfur.

TABLE 6-11
INFRASTRUCTURE DEVELOPMENT COSTS ASSOCIATED
WITH UNIT COAL LIQUEFACTION PLANTS

	Peak Construction		Operation (a)	
	Fischer-Tropsch	Other	Fischer-Tropsch	Other
Total employment	4,376	3,250	5,682	3,583
Total population	11,680	8,680	15,170	9,567
Investment in existing communities (million dollars)	35.0	39.0	45.5	43.0
Additional investment for new communities (million dollars)	17.5	13.0	22.8	14.3

a) Assumes 1500 surface miners for Fischer-Tropsch plant and 785 for other liquefaction plants.

6.9 Demand for community services

Table 6-13 lists the estimated service requirements resulting from a unit liquefaction plant. These figures represent the additional services required if all employees come from outside the region. The total population is taken as 2.67 times the number of employees, and the number of school age children is taken as two-thirds the number of employees. The standards presented in Chapter 5, Section 9 are used as a basis for determining the service requirements.

6.10 Reversible and irreversible commitment of resources

Unit liquefaction plants will require about 800 acres for equipment, storage areas, holding ponds, etc. Land used for supportive coal mining is tabulated in Table 6-14. The impact on resources is similar to that for coal gasification plants.

TABLE 6-12
EMPLOYMENT FROM A UNIT COAL LIQUEFACTION PLANT (a,b)

	Primary		Secondary		Total	
	Fischer-Tropsch	Other	Fischer-Tropsch	Other	Fischer-Tropsch	Other
1. Construction						
1st year	253	255	454	460	707	715
2nd year	442	508	796	914	1,238	1,422
3rd year	455	508	820	914	1,257	1,422
4th year	677	438	1,218	788	1,895	1,226
5th year	171	166	307	299	478	465
Peak	1,563	1,161	2,813	2,089	4,376	3,250
2. Operation	529	495	953	890	1,482	1,385
3. Mining						
• Appalachia						
- Monongalia Co., W.V.						
--Underground	2,987	1,558	5,376	2,804	8,363	4,398
--Surface	1,335	696	2,403	1,254	3,738	1,950
- Belmont Co., Ohio						
--Underground	3,156	1,647	5,681	2,965	8,837	4,612
--Surface	1,411	737	2,539	1,326	3,950	2,063
- Jefferson Co., Ala.						
--Underground	3,022	1,576	5,440	2,837	8,462	4,413
--Surface	1,353	705	2,435	1,270	3,788	1,975
• Eastern Interior						
- Fulton Co., Ill.	1,031	540	1,856	972	2,887	1,512
- Henderson Co., Ky.	955	500	1,720	900	2,675	1,400
• Powder River						
- Cambell Co., Wyo.	429	223	771	401	1,200	624
• Fort Union						
- Mercer Co., N.D.	603	304	1,085	546	1,688	850
• Four Corners						
- San Juan, N.M.	487	254	876	458	1,363	2,239
Total During Operation			Minimum		2,682	2,009
			Maximum		10,319	5,997

(a) 328 operating days per year (90% stream factor).

(b) Based on the following productivity rates for miners (tons/person-day):

Appalachia		Powder River	100
Underground	11.2	Fort Union	100
Surface	29.7	Four Corners	82
Eastern Interior	37		

Source: *Synthetic Fuels Commercialization Program* [1].

TABLE 6-13

MAXIMUM ADDITIONAL DEMAND FOR COMMUNITY
SERVICES FOR A UNIT COAL LIQUEFACTION PLANT

Service Category	Peak Construction		Operation ^(a)	
	Fischer-Tropsch	Other	Fischer-Tropsch	Other
Doctors				
Primary	10	7	12	7
Specialty	8	5	9	6
Hospital Beds	46	35	56	36
Dentists	6	4	7	4
Law Officers	23	17	28	18
Police Cars	6	4	7	4
Firemen	12	9	14	9
Teachers				
K-6	80	60	143	92
7-9	40	29	71	46
10-12	40	29	71	46
Sanitary Landfill (acres)	46.7	34.6	55.9	35.8
Sewage Treatment (thousand gallons/day)	438	325	568	358
Water requirements (thousand gallons/day)	745	553	966	609

a) Assumes 1500 strip miners for Fischer-Tropsch plant and 785 for other liquefaction plants.

Based on assumptions in *Synthetic Fuels Commercialization Program*, which have been listed in Section 5.9.

TABLE 6-14
LAND REQUIRED FOR MINING TO SUPPORT A
UNIT COAL LIQUEFACTION PLANT (a,b,c)
(acres/year)

Region	Location	Type	Coal Bed	Type of Mining	SRC	Catalytic Hydrogenation	Fischer-Tropsch
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	Underground Surface	40 156	63 254	107 424
	Belmont Co., Ohio	Bituminous	Pittsburgh	Underground Surface	58 228	94 375	161 625
	Jefferson Co., Ala.	Bituminous	Blue Creek	Underground Surface	40 161	63 259	107 429
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	Surface	174	277	460
	Henderson Co., Ky.	Bituminous	No. 9	Surface	254	411	688
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	Surface	31	49	80
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	Surface	107	179	308
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	Surface	134	214	366

a) 328 Operating days a year (90% Stream Factor).

b) Based on seam thickness

Appalachia	7 feet (Monongalia Co., W.Va.)
	5 feet (Belmont Co., Ohio)
	7 feet (Jefferson Co., Ohio)
Eastern Interior	8 feet (Fulton Co., Ill.)
	5 feet (Henderson Co., Ky.)
Powder River	60 feet (Campbell Co., Wyo.)
Fort Union	20 feet (Mercer Co., N.M.)
Four Corners	11.8 feet (San Juan Co., N.M.)

c) All wastes and overburden are assumed to be returned to the mine site.

Source: *Synthetic Fuels Commercialization Program* [1].

6.11 Difficulties in commercialization of the conversion processes

Coal liquefaction, like gasification, has received limited commercial application for decades. The purpose of technological research is to make the conversion more profitable and reduce the risk to investors. Other areas of concern are the availability of adequate water supplies in the West and possible water contamination from mining and waste material.

6.12 Current status and selected process descriptions

Coal liquefaction has been technically feasible for several decades. It has not received commercial application in the United States due to unfavorable economics.

Liquefied coal can be refined into several fuels and chemical feedstocks currently supplied by petroleum products. Many of the processes also remove most of the sulfur and ash present in unprocessed coal, thereby engendering a drastic reduction in its environmental impact. For these reasons, the Department of Energy is supporting several projects aimed at developing economical liquefaction processes. In fiscal year 1978, \$107 million was allocated. The status of several projects was given in Table 4-1.

6.12.1 H-COAL

The H-Coal Process is being developed by Hydrocarbon Research, Inc. (HRI) under the joint sponsorship of (1) DOE; (2) a private industry consortium composed of EPRI, Ashland Oil, Inc., Atlantic Richfield Company, Shell Oil Company, Standard Oil Company (Indiana), Sun Oil Company; and (3) the Commonwealth of Kentucky. The plant site is located at Catlettsburg, Kentucky. The total project funding is \$44.4 million with DOE supplying \$32.7 million and industry \$11.7 million.

The H-Coal Process was developed by HRI as a further application of the ebullated-bed processing technology originally used to convert heavy oil residues from petroleum into lighter fractions (H-Oil Process). Early development of the H-Coal Process, beginning in 1964, involved research with a bench-scale unit and a process development unit and preparation of a conceptual process design. An independent evaluation in 1968 confirmed the technical and economic feasibility of the H-Coal Process.

Based on the data obtained from the bench-scale and process development units, design and engineering of the pilot plant began under the current contract in December 1973. During 1974, design of the coal preparation section of the pilot plant was completed to the extent that engineering and plant layout could begin. HRI concentrated, however, on the design and engineering for the ebullated-bed reactor, since the equipment needed for this section requires long lead times. Engineering for other sections of the pilot plant was in late 1974. Also during 1974, three possible sites for construction of a pilot plant were evaluated. Based on detailed environmental assessments, it was decided during the second quarter of 1975 to locate the plant adjacent to the Ashland Oil, Inc. refinery in Catlettsburg, Kentucky. Except for the steam supply, this arrangement would allow the utility system of the pilot plant to be shared with that of the refinery. All process descriptions, equipment specifications, and planning drawings were completed for the coal preparation section. Work in the hydrogenation

area involved the modification and rearrangement of major equipment to conform to the physical characteristics of the new plant site. Preliminary process designs were also completed for the solid-liquid separation techniques of filtration, centrifugation and solvent precipitation.

The H-Coal Process is a catalytic hydroliquefaction process that converts high-sulfur coal to boiler fuels and synthetic crude. Coal is crushed, dried, slurried with recycled oil, and is then pressurized to about 200 atm. Compressed hydrogen is added to the slurry, the mixture is preheated and charged continuously to the bottom of the ebullated-bed catalytic reactor is controlled by adjusting the preheater outlet temperature. Typically, the temperature of the mixture entering the reactor is 650°F to 700°F.

Vapor product leaving the top of the reactor is cooled to separate the heavier components as a liquid. Light hydrocarbons, ammonia, and hydrogen sulfide are absorbed from the gas stream and sent to a separator and a sulfur recovery unit. The remaining hydrogen-rich gas is recompressed and combined with the input slurry. The liquid from the condenser is fed to an atmospheric distillation unit. The liquid-solid product from the reactor, containing unconverted coal, gas, and oil, is fed into a flash separator. The material that is flashed off is passed to the atmospheric distillation unit which yields light and heavy distillate products. The bottoms product from the flash separator, solids and heavy oil, is further separated with a hydroclone, a liquid-solid separator, and by vacuum distillation.

The gas and liquid products, composed of hydrocarbon gases, hydrogen sulfide, ammonia, light distillate, heavy distillate and residual fuel, may be further refined as necessary. A portion of the heavy distillate is recycled as the slurry medium. The stream containing the unreacted carbon and some liquid will eventually be processed in a commercial installation to produce additional hydrogen needed for the process.

Before the H-Coal Process can become commercially and economically competitive, a method for generating an adequate supply of hydrogen from the process itself must be developed. This is an unsolved problem. The H-Coal Process requires between 14,000 and 20,000 standard cubic feet of hydrogen for each ton of coal processed, depending on the type of oil produced. In the pilot plant some of the hydrogen required has been obtained from the gas produced by the ebullated-bed reactor. Additional hydrogen has been purchased to meet processing demands. In a commercial operation, hydrogen demand will be met by manufacture on-site. Because the H-Coal Process converts about 90 percent of the carbon contained in the coal to a liquid, the feed to the hydrogen plant could be liquid rather than solid. This suggests that commercial hydrogen manufacturing processes could be adapted. The solid cake char would also be used to produce hydrogen.

Another of the principal unsolved problems in the H-Coal Process (and in other liquefaction processes) is the effective separation of the solids from the fuel products. In the H-Coal Process, hydroclones are capable of removing about two-thirds of the solids so that the liquids can be recycled for slurrying the coal. HRI has also been investigating other methods of separating solids from liquids, such as magnetic separation, filtration, centrifugation, and solvent precipitation. Magnetic separation has shown only limited effectiveness. Separation of the solids by filtration has not been conclusive,

although filtration rates of 150 lb/hr/sq ft and relatively dry filter cakes have been achieved by using continuous drum pressure filters.

Maintenance and cleaning of the reactor section will require specific procedures and facilities. The reactor will contain several tons of oil slurry, which must be removed when the plant is shut down. Suspended solids will be present, as well as catalyst particles. One possibility is to store the materials removed from the reactor in suitable tanks for reuse or proper ultimate disposal. The oil is probably similar to other coal tar materials which are known to be carcinogenic, so this aspect should be evaluated and precautions taken as needed. It may be desirable to flush out the system with a neutral wash oil before opening up equipment for maintenance.

Sour water is the major liquid stream from gas separation and cleanup. It is sent to waste water treating where contaminants are removed so that it can be reused as makeup to the cooling water circuit. The sour water will contain a wide range of contaminants including compounds of sulfur, nitrogen, or oxygen, as well as some oil and possible solids. In addition there may be certain trace elements that could be partially vaporized in the liquefaction reactor and carried out with the gas.

Cleanup of the sour water may require solvent extraction to remove phenols if these are present in large amounts. The phenols may then be withdrawn as a by-product if an outlet is available, or possibly they could be recycled through hydrogenation to destroy them. Sour water stripping will remove most of the ammonia and hydrogen sulfide. Ammonia may be recovered separately as a by-product, while the hydrogen sulfide should be sent to the sulfur plant.

The final step in gas cleanup is sulfur removal. This provides a clean stream of product gas that is low enough in sulfur so that it can be burned without requiring control of sulfur emissions. The main effluent is a sulfur containing gas stream that is sent to a plant for sulfur recovery. Concentrations of hydrogen sulfide are separated in acid gas removal. In general, scrubbing for acid gas removal will require some makeup of chemicals which must show up as a corresponding effluent. Typically, this is a chemical purge stream, which in the case of amine scrubbing might be disposed of by incineration. An alternative to consider might be to send it to waste water treating.

From the oxygen plant the only liquid effluent is a small amount of clean water condensed from the air, which can be used as boiler feed water makeup. From the sulfur plant, the main output is by-product sulfur which is suitable for sale. Tail gas cleanup involves scrubbing with chemicals resulting in a purge stream of chemicals that requires specific plans for disposal, depending upon its exact nature.

During hydroliquefaction, some of the minor or trace elements in the coal deposit on the catalyst. Eventually, the catalyst must be regenerated or reworked. Specific plans are necessary to handle and dispose of spent catalyst. One possibility is to return it to a manufacturer for reworking and metals recovery. If it is to be buried or stored, the extent of leaching needs to be defined and adequately controlled. (4,6,7,8,9,10)

6.12.2 EXXON DONOR SOLVENT

The Exxon Donor Solvent Process is being developed by the Exxon Research and Engineering Company, Baytown, Texas. A \$12 million contract between DOE

and Exxon was initiated in January 1976. However, under the terms of the contract, details of prior development work on the process conducted between 1966 and January 1976 are confidential.

Exxon's research on the Donor Solvent Process began in 1966 and has resulted in a commercial study design. A semi-empirical kinetic model of liquefaction yields from Illinois coal has been expanded to include recent results from high-severity liquefaction experiments. Progress has been made in the development of a computer model of the entire integrated Donor Solvent Process. The model will simulate, and link together in a single interfacing package, the six major processing sections: (1) liquefaction, (2) solvent hydrotreating, (3) coking, (4) cryogenic hydrogen recovery, (5) steam/methane reforming, and (6) final product separation.

Evaluation of several process alternatives has begun, including development of a computerized process alternative model to be used as a basic tool for the process engineering and economic studies which are planned. Engineering studies have been initiated to identify and develop equipment and engineering data needed for a safe, operable, and reliable Donor Solvent commercial plant.

Steps in the Donor Solvent Process involve engineering and design technology similar to that practiced in the petroleum industry. The process was designed to permit process control, allow for feeding different coals, and allow product distribution to vary based on market demand. In this process, the donor solvent provides a mechanism to allow intimate contact between hydrogen and dispersed coal fragments. The donor hydrogen content of the spent solvent is restored after liquefaction in the solvent hydrogenation reactor. This step also reduces the sulfur, nitrogen, and oxygen contents of the recycled solvent. The donor hydrogen content is the major parameter used to evaluate the effectiveness of various catalysts and processing conditions to produce good quality donor solvent.

The coal is dried, ground and mixed with recycle solvent to form a slurry. Hydrogen is normally preheated separately and combined with preheated slurry at the reactor inlet. An alternate mode of operation is to combine the hydrogen with the slurry before preheating.

After liquefaction, the product goes to the first stage of separation. Water is removed, hydrogen is recycled, and heavy liquid products are sent to the vacuum separation section.

The primary vacuum flash tower removes the mineral matter and unreacted coal. The secondary vacuum tower is used to remove a heavy distillate which becomes the endpoint of the recycle solvent. This overhead from the secondary vacuum flash tower is then combined with the lighter liquid stream recovered from the liquefaction reactor-separator system and fed to the solvent hydrotreating section, consisting of fixed-bed catalytic reactors. The solvent and naphtha from the solvent hydrotreating section are then separated by fractionation. Most of the solvent is recycled, as is the hydrogen, after undergoing cleanup in a monoethanolamine scrubbing system.

Environmental quality data for the Donor Solvent Process are not available because a plant has not yet been constructed, and because of the proprietary nature of the contract. However, pollutant emissions are expected to meet all applicable

standards and are not anticipated as being significantly different from those of other coal liquefaction processes. (4,5,7,8,10,11)

6.12.3 SOLVENT REFINED COAL (SRC)

The SRC Process is being developed by Pittsburgh & Midway Coal Mining Company (PAMCO), a subsidiary of Gulf Oil Corporation, under the sponsorship of DOE. A 50 T/D pilot plant is located in Ft. Lewis, Washington, and current funding, 100 percent supplied by DOE, is set at \$82 million. The operation and evaluation of the modified pilot plant is scheduled to run through 1980.

A 6 T/D pilot plant, sponsored by DOE, EPRI, and Southern Company Services is operating at the Gaston steam power plant located near Wilsonville, Alabama.

The SRC project began in 1962 when Spencer Chemical Company was awarded a research contract by the OCR (now a part of DOE) to study the technical feasibility of a coal de-ashing process, now called the SRC Process. In 1985, the process was successfully demonstrated in a 50-pound-per-hour continuous-flow unit, and the work on the contract was therefore completed. During the term of the contract, Gulf Oil Corporation acquired Spencer Chemical Company. After reorganization, the contract was assigned to the research department of PAMCO.

To develop the SRC Process further, a contract was awarded to PAMCO to design, construct, and operate a pilot plant that would be capable of processing 50 tons of coal per day. In 1968, Stearns-Roger Corporation completed the design for the pilot plant, but funds to begin construction were not available until late 1971. In June 1972, OCR extended its contract with PAMCO to construct and operate the pilot plant. Rust Engineering Company began constructing the pilot plant in July 1972 at Ft. Lewis, Washington, near Tacoma. As units were completed, preliminary tests of process equipment and instrumentation were performed. The pilot plant became fully operational in October 1974.

Eleven material balance runs were made on the SRC pilot plant in the distillate solvent mode during 1975. Five successful runs were also made during 1975 in the slurry recycle mode. Overall, the 50 T/D pilot plant operated smoothly throughout 1975.

The laboratory unit was also run in both the distillates solvent and slurry recycle mode during 1975. The variables investigated included filtration rate, solvent recycling, slurry residence time, concentration of coal in the slurry and temperature.

The pilot plant was modified in 1977 to incorporate what is called SRC II. SRC I creates a solid fuel as its final product. However, it is a solid with a lower melting point than regular coal; hence, its categorization as a liquefaction process. SRC II produces a liquid as the actual end result.

Coal is first pulverized and mixed with a coal-derived solvent in a slurry mix tank. The slurry is combined with hydrogen and is then pumped through a fired preheater and passed into a dissolver. In this unit, the coal is hydrogenated and thereby depolymerized, leading to an overall decrease in product molecular weight and dissolution of the coal. The solvent is also hydrocracked in the dissolver unit, yielding lower

molecular weight hydrocarbons ranging from light oil to methane. Yet another reaction occurring in the dissolver is the hydrogenation of the organic sulfur in the coal thus producing hydrogen sulfide.

From the dissolver, the mixture passes to a separator where the gases are separated from the slurry of undissolved solids and coal solution. The raw gas is sent to a hydrogen recovery and gas desulfurization unit. The recovered hydrogen is then recycled and combined with the slurry coming from the slurry mix tank. Hydrocarbon gases are released and recovered, and the hydrogen sulfide is converted to elemental sulfur.

In the SRC I Process the slurry of undissolved solids and the coal solution is then separated in a filtration unit. In a commercial-scale process, the solids would be sent to a gasifier-converter where they would react with supplemental coal, steam, and oxygen to produce hydrogen for use in the process. The coal solution passes to the solvent recovery unit, and the product, solvent-refined coal, is produced. This material has a heating value of approximately 16,000 Btu/lb. However, this filtration step, along with the cost and operational difficulties associated with it, is eliminated in SRC II.

SRC II recycles a portion of the slurry to the front end of the plant. More time in the reactor increases the yield of liquid product.

The environmental aspects of an SRC plant are similar to those encountered in power plants (coal dust, flue gases), coke plants (coal tar hydrocarbons), and petroleum refineries (solvents, tars, and residues).

No unique problems and no greater difficulty in meeting the environmental standards of these industries are anticipated for a commercial SRC plant.

Specifically, fugitive particulates (dust) and vapors can originate in several areas throughout the plant. Dust emissions are imminent when the coal is pulverized, or the mineral residue is dried and discharged. These emissions are controlled by using covered conveyors and induced draft vents with the vent gas being filtered to remove particulates. Coal is pulverized in a gas-swept grinding mill. As the coal is pulverized, it is dried by a hot, inert gas and carried into a bag house. Here the dried, powdered coal is collected for discharge in the slurry blend tank. This operation is in a closed system. The slurry is filtered. Diatomaceous earth, with or without asbestos, is used as a filter aid on the rotary filters.

In order to reduce vapors from the solvent tanks and other vessels, they are filled with inert gas. As the inert gas blanket is purged when a vessel is filled, the gas and vapors are discharged into an inert gas flow. This flow, as well as all of the other gases purged from the plant, goes into the flare piping system to be carried to the flare stack. All safety relief valves are also connected to the flare piping system. Flare burning is supplemented, if necessary, with natural gas.

Most of the sulfur liberated from the coal during processing appears as hydrogen sulfide in various gas streams. Hydrogen sulfide and carbon dioxide, the acid gases, are separated from the gas stream by an amine absorption unit. This concentrated hydrogen sulfide stream is converted to elemental sulfur as a by-product. In a commercial plant, a sulfur plant would probably be used with an appropriate tail gas cleanup unit.

Liquid waste streams from the plant are combined and treated in a waste treatment plant by clarification, biological treatment, sand filtration, and carbon filtration. No unusual or unexpected problems have been encountered in the operation of this equipment.

The disposal of residue raises a primarily economic question. In a commercial plant, utilization of by-product instead of disposal would make the process more economical. One method is to gasify the char. By an alternate method, a slagging gasifier would convert the residue into a relatively clean slag and synthesis gas (hydrogen and carbon monoxide). The sulfur in the residue would be converted into hydrogen sulfide which would appear in the synthesis gas and could be removed by usual acid gas removal methods.

A program has been developed for the application of instrumental neutron activation analysis to determine trace elements throughout the SRC plant. (4,6,7,12)

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CHAPTER 7

OIL SHALE TO GAS AND OIL

7.1 Brief Technical Description

Oil shale is a sedimentary rock in which oil is found as solid organic material called kerogen. When heated, the kerogen, which contains substantial hydrogen, decomposes into a heavy liquid resembling crude oil, from which any desired hydrocarbons can be synthesized.

Oil shales are found in many locations throughout the world. In the U.S. there are enormous deposits in the Green River formation surrounding the intersection of the borders of Colorado, Wyoming and Utah. The highest grade reserves are located in the Piceance Basin in Western Colorado, where the "mahogany zone" of oil shale is 30 to 100 feet thick and located within 1000 ft. of the surface. It has 30 or more gallons of oil per ton of rock and has been of commercial interest for over a hundred years. The current high price of imported oil may result in its commercial exploitation.

The fundamental difficulty with oil shale is in extraction of the shale and its eventual return to the ground. It takes about 1.2 tons of oil shale to produce a barrel of oil, whereas only about one-third ton of coal is necessary.

In some oil shale processes, the spent shale expands about 50 percent, creating disposal problems. A notable exception is the Paraho process, in which the spent shale maintains its original size.

Fortunately, the processes for extracting oil from the shale are very simple. All involve retorting (heating) the rock to about 800°F, condensing the distillate, and collecting the liquid oil which runs from the rock. The retorting heat can be supplied by direct combustion or through indirect heating.

Processes

In the Gas Combustion process which was developed by the U.S. Bureau of Mines in the 1950s, (Figure 7-1) crushed rock is fed to the top of the retort and falls gradually through four reactor zones. The first zone preheats the shale, the second retorts it, and in the third zone air is introduced to burn the residual carbon on the retorted shale, providing heat for the retorting. In the fourth zone upflowing cooled, recycled product gas cools the retorted shale before it leaves the retort.

The Petrosix and Paraho (Figure 7-2) processes are similar but the heat is provided by burning recycled gas outside the reactor. The lack of flame produces better quality oil and spent shale.

The Union Oil process is also similar but uses a "rock pump" to propel rock from bottom to top of the bed instead of vice versa. Gas flow is downward, and the combustion zone is near the top. The reversed flow keeps the retorted oil from dropping through the combustion zone, reducing coking problems but adding mechanical complexity. The process is illustrated in Figure 7-3.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 7-1. Gas combustion process.

Source: *The Energy Source Book* (2).

Figure 7-2. Schematic of Paraho oil shale process.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 7-3. Union oil process.

The TOSCO II process (Figure 7-4) is considerably more complex, using separately heated ceramic balls to retort the shale in a horizontal, rotating kiln. The shale, crushed to less than one-half-inch size, is fed into a fluidized bed where it is preheated by hot combustion gases from a separate ball heater. After preheating, the shale is moved into the reactor and mixed with half-inch diameter heated ceramic balls from the ball heater. The heat in these balls transfers to the shale, effecting pyrolysis. The oil, steam, and gases are given off as a mist, which is fed to a fractionator for product recovery. The spent shale and ceramic balls are discharged from the pyrolysis drum and separated by a trommel screen. The balls are returned to the ball heater, and the spent shale is removed for disposal (1).

A fractionator (cyclone separator) separates the oil from the gas output. The gas is then burned to heat the balls in the ball heater. Since no combustion takes place in the reactor vessel, the resulting gas has a higher energy content and the oil a lower viscosity than that from an internally heated retort. These features, and the reactor's ability to handle fine particles, are advantages of the TOSCO II process.

The Superior Oil process incorporates steps to recover nahcolite (NaHCO_3), soda ash (Na_2CO_3) and aluminum compounds. By removing these materials the spent shale is reduced to 90% of the original shale volume (3).

In-Situ Shale Retorting

Oil shale can be gasified by true in situ processing just as coal can be, using boreholes for air (or oxygen) injection and product removal. The liquid product can also be withdrawn, if desired, for it accumulates in the bottom of the mixed volume. The formations must be fractured by hydraulic pressure or by explosives, however, since they are not usually permeable.

In the modified in situ process developed by the Occidental Oil Company, 15 to 20% of the shale is mined and explosives are used to "rubblize" the remainder. An underground retort is then initiated, using a limited amount of air. A schematic diagram is shown in Figure 7-5.

Upgrading

The crude shale oil is too viscous for pipeline transport and cannot be burned directly, because it has a high content of sulfur and nitrogen. Upgrading refers to a series of processing steps, which include separation of the oil into different fractions, hydrotreating the fractions (to crack the large molecules and remove sulfur and nitrogen), H_2S and ammonia stripping and recovery, and generation of hydrogen from the off-gases produced by hydrotreating.

7.2 Quantity and Type of Primary Source

A unit shale oil plant is taken as one producing 45,000 barrels per day of (upgraded) syncrude, i.e., about 250 billion Btu/day. The energy content of the syncrude is between 5.4 and 5.8×10^6 Btu/bbl; externally heated retorts yield a product nearer the upper end.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 7-4. TOSCO II process.

Source: *The Energy Source Book* (2).

Figure 7-5. Modified in situ process.

The amount of shale required for a unit plant depends on the process efficiency and its kerogen content (which will be at least 30 gallons/ton for initial commercial investments). For the purposes of this report, a unit plant is assumed to require 70,000 tons/day of high grade shale. A typical oil shale analysis is given in Table 7.1.

7.3 Quantity and Type of Other Resources Used for Energy Conversion

Auxiliary Fuel

No outside auxiliary energy is needed, in spite of the considerable electric power requirements, since considerable amounts of low Btu gas are generated during retorting and upgrading.

Water

Large quantities of water are required for dust control during mining, crushing and disposal operations in addition to that required for retorting, upgrading and power generation. The requirements are summarized in Table 7-2 for the three mining options.

TABLE 7-1
TYPICAL OIL SHALE COMPOSITION

ORGANIC MATTER (13.7% by weight)		MINERAL MATTER (86.3% by weight)		AVERAGE MAHOGANY ZONE OIL SHALE COMPOSITION		
	% weight		% weight		% weight	1 ton yields
Carbon	80.5	Carbonates	50.0	Oil	10.9	28.4 gallons
Hydrogen	10.3	Feldspars	19.0	Water	0.8	1.9 gallons
Nitrogen	2.4	Illite	15.0	Gas and Losses	2.0	400 scf
Sulfur	1.0	Quartz	10.0	Spent shale	86.3	1726 pounds
Oxygen	5.8	Analcite	5.0			
Pyrite	1.0					

Source: *The Energy Source Book* (2).

The Paraho process requires no water for retorting, but instead can produce it as a by-product. In addition, upgrading will occur at the refinery rather than on site. These differences allow water consumption to be reduced to 2.3 million gallons/day, needed for dust control, spent shale disposal, etc. (4).

Catalysts

The catalyst requirements given below (5) are those determined for a 100,000 bbl/day Tosco II plant, but other processes will have similar needs:

- Naphtha and gas oil hydrotreaters
 - 670 tons/2 yr (max.) hydrodenitrogenation catalyst
- Steam reformer
 - 270 tons/4 yr cobalt-molybdenum hydrodesulfurization catalyst
 - 30 tons/2 yr zinc oxide sulfur guard
 - 100 tons/5 yr iron-chromium CO shift catalyst
 - 100 tons/3 yr copper-zinc CO shift catalyst hydrotreater catalyst
- Sulfur conversion
 - 300 tons/2 yr bauxite claus plant catalyst
 - 200 tons/5 yr cobalt and nickel molybdate tail gas hydrotreater catalyst

TABLE 7-2
WATER CONSUMED BY OPTIONAL MINING
METHODS FOR UNIT SHALE OIL FACILITY
(Million gallons/day)

Process Requirements	Underground Production	Surface Mine Production	In Situ Production	Modified In Situ Process
Mining and Crushing	0.33 - 0.45	0.32 - 0.45	-	0.15 - 0.20
Retorting	0.51 - 0.65	0.52 - 0.65	-	0.23 - 0.29
Shale Oil Upgrading	1.29 - 1.94	1.29 - 1.94	1.29 - 1.97	1.29 - 1.97
Process Shale Disposal	2.57 - 3.90 ^(a)	2.59 - 3.88	-	1.15 - 1.84
Power Requirements	0.65 - 0.90	0.65 - 0.90	0.65 - 1.61	0.65 - 1.47
Revegetation	0 - 0.62	0 - 0.62	0 - 0.62	0 - 0
Sanitary Use	0.02 - 0.04	0.01 - 0.03	0.02 - 0.04	0.02 - 0.04
TOTAL	5.38 - 8.52	5.39 - 7.59	2.66 - 5.06	3.05 - 6.43

a) Water used is 20% by weight of the disposed spent shale.

Adapted from *Synthetic Fuels Commercialization Program* [6] and *Environmental Considerations for Oil Shale Development* [7].

7.4 Environmental Control Processes

Particulate and sulfur oxides emissions from ancillary fuel combustion are controlled by the methods discussed in Chapter 5, Section 4. Retorting produces a liquid with high concentrations of nitrogen and sulfur. In order to avoid undesirably large emissions of nitrogen and sulfur oxides during combustion, these concentrations are reduced during upgrading. This is accomplished by hydrogenation, with the necessary hydrogen generated on-site from by-product gases. The reduced forms of nitrogen and sulfur, HN_3 and H_2S , are separated from the liquid and processed in ammonia and sulfur recovery units.

7.5 Primary and Secondary End Products

Because the crude shale oil produced by retorting is difficult to transport, it will probably be upgraded on site. However, the upgraded syncrude will be refined to conventional petroleum products elsewhere, due to water limitations. Thus, the primary local products will include:

- 45,000 bbl/day of synthetic crude oil (properties listed in Table 7-3).
- Retort gases:
 - Internal combustion retorting produces about 10,000 scf/bbl (standard cubic feet per barrel) of low Btu gas (about 100 Btu/scf) which will be used on site for power generation and/or upgrading (3).
 - Externally heated retorts produce about 900 scf/bbl of high Btu gas (800 - 900 Btu/scf) which can be used on site or transported (3).
 - In situ retorting produces large quantities of low quality gas (30 Btu/scf) which have been flared in the past (3).
 - The modified in situ process reportedly produces a gas suitable for power generation (4).

The following by-products of upgrading can be recovered using well established technologies (5).

- Ammonia, 150 tons/day.
- Sulfur, 200 tons/day.
- Coke, which would be used on site due to low quality, 800 tons/day.

The Superior Oil Process has demonstrated that valuable minerals can be recovered from spent shale. These include (8):

- Nahcolite (NaHCO_3), about 6.15 million tons/year.
- Soda ash (Na_2CO_3), about 2.16 million tons/year.
- Alumina (Al_2O_3), about 846,000 tons/year, which could be converted to supply almost 10% of the nation's 1976 primary aluminum production.

7.6 Residuals: Quantity, Type, Environmental Significance, Current Legislation

Air emissions

Estimated quantities of major air pollutants from mining, preparation, retorting, upgrading, power generation, and spent shale disposal are given in Table 7-4. Significant deviations from these estimates could arise from a number of factors, including the use of other processes and pollution control methods. The most serious potential problems are:

- The substantial amounts of particulates resulting from mining, crushing and spent shale disposal (above ground processes).
- Flaring of off-gases in the BuMines in-situ process.
- Hydrocarbons released during upgrading (all processes).

TABLE 7-3
TYPICAL PROPERTIES OF CRUDE SHALE OIL AND SYNCRUDE

	Crude Shale Oil	Syncrude
Gravity, °API	28.0	46.2
Pour Point, °C	24	10
(°F)	(75)	(50)
Sulfur, wt %	0.8	0.005
Nitrogen, wt %	1.7	0.035
Reid Vapor Pressure, atm	-	1.5
(psi)	-	(8)
Viscosity, centistoke @ 38°C	25.4	4.3
(SUS @ 100°F)	(120)	(40)
<u>Analysis of Fractions</u>		
● Butanes and Butenes, vol %	4.6	9.0
● Naphtha [<177°C (350°F)]		
Vol %	19.1	27.5
Gravity, °API	50.0	54.5
Sulfur, wt %	0.70	<0.0001
Nitrogen, wt %	0.75	0.0001
K Factor	11.7	12.0
Aromatics, vol %	-	18
Naphthenes, vol %	-	37
Paraffins, vol %	-	45
● Light Distillate [177-288°C (350-550°F)]		
Vol %	17.3	41.0
Gravity, °API	31.0	38.3
Sulfur, wt %	0.80	0.0008
Nitrogen, wt %	1.35	0.0075
Aromatics, vol %	-	34
Freezing Point, °C (°F)	-	-37 (-35)
● Middle Distillate [288-455°C (555-850°F)]		
Vol %	33.0	22.5
Gravity, °API	21.0	33.1
Sulfur, wt %	0.80	<0.01
Nitrogen, wt %	1.90	0.12
Pour Point, °C (°F)	-	27 (80)
● Heavy Distillate Plus Residue [>455°C (850°F)]		
Vol %	26.0	None
Gravity, °API	12.0	
Sulfur, wt %	1.0	
Nitrogen, wt %	2.4	

Source: *Environmental Considerations for Oil Shale Development* (7).

The Colorado Air Pollution Commission recently relaxed its sulfur dioxide standard to 0.18 kg per million Btu's (the federal standard is 0.54 kg/MMBtu). Only flared LBG from the Bu Mines in situ process exceeds this standard.

Water emissions

It is anticipated that no water will be discharged from the plant, but will be used instead as cooling tower make-up or for dust suppression. Despite this, two areas of concern remain:

- Leaching of sulfates; carbonates; sodium, calcium, and magnesium salts; trace metals; and residual organics could create a serious hazard to both human health and aquatic life. Known carcinogens have been found in spent shale, but the extent of leaching has not yet been determined (3).
- Saline water encountered during mining will require proper disposal because high salinity is already a problem in the Green River area.

Solid Waste

Waste disposal presents a tough, though not insurmountable, challenge to the oil shale industry. In most above ground processes the shale volume increases during retorting, and a unit plant will produce about 60,000 tons of this expanded waste each day. This is over 40 times the amount produced by a unit high Btu coal gasification plant using Wyoming coal. As mentioned previously the disposal of spent shale causes substantial particulates pollution and may result in the contamination of water supplies with hazardous substances.

A commercial oil shale industry will probably rely on some combination of the following techniques, many of which are currently under investigation:

- Returning spent shale to underground mines.
- Using an above ground process which does not result in shale expansion (e.g. the Paraho process).
- Using an in situ method of retorting or the modified in situ method, which produces only 15-20% as much waste as above ground processes.
- Recovering minerals from the spent shale, which leaves less residual (90% of the original shale volume in the Superior process).
- Compacting the shale, with the possible additional benefit of making it impermeable to water.
- Piling the material in a deep canyon and diverting run-off away from the area.

Surface mining exacerbates the disposal problem by the quantity of overburden removed. Underground mining will probably be used to supply above ground plants

TABLE 7-4
AIR EMISSIONS FROM UNIT OIL SHALE OPERATIONS
(tons/day)

Operation	Type	Parti- culates	Sulfur oxides	Nitrogen Oxides	Hydro- carbons	Carbon Monoxide	Alde- hydes
Mining	Underground	0.147	0.002	0.033	0.003	0.019	0
	Surface ^(a)	0.005	0.012	0.158	0.016	0.095	0.001
Crushing	(above ground)	.210	0	0	0	0	0
Retorting	Gas Combustion	0	0	0	0	0	0
	TOSCO II	0	0	0	0	0	0
	BuMines In Situ ^(b)	1.56	65.6	U	37.9	2.83	U
Power/Steam Generation	Gas Combustion	1.01	7.27	8.88	0.912	0.009	0.068
	TOSCO II	0.044	8.85	3.21	0.332	0.003	0.025
	BuMines In Situ	0.072	0.003	1.88	0.191	0.002	0
Upgrading	(all)	0	0.381	0	2.17	0	0
Spent Shale Disposal	Above ground	0.545	U	U	U	U	U
	In Situ	0	0	0	0	0	0

(a) Does not include overburden disposal.

(b) Assumed byproduct LBG is flared.

U = Unknown.

Adapted from *Synthetic Fuels Commercialization Program* [6] and *Environmental Considerations for Oil Shale Development* [7].

except in areas with very shallow overburden. (Much of the "mahogany zone" oil shale is about 900 feet below the surface.)

7.7 Process Economics

Economic data has been reported for a Tosco II plant producing 55,000 bbl/day of crude shale oil which is upgraded to 48,000 bbl/day of syncrude, and 150, 135 and 660 tons/day of sulfur, ammonia and coke, respectively (9). The figures presented here for this process are in September, 1975 dollars.

Total capital investment was estimated at \$960 million, including costs associated with startup, working capital, community assistance (\$28 million), project management and pre-commitment. It was assumed that the plant is financed on a 100 percent equity basis; that is, there is no debt service since no money is borrowed.

Operating costs were projected at \$75 million per year, with mining, crushing and spent shale disposal as the largest contributing factor, \$30 million per year. Including by-product credits totaling \$0.61 per barrel, syncrude prices of \$14.20, \$18.30 and \$21.70 per barrel are required to provide after tax discounted cash flow (DCF) rates of 10, 13 and 15 percent, respectively.

In contrast, Paraho predicts a DCF return of 12 percent for raw shale oil (not upgraded) produced by a 60,000 bbl/day plant at a cost of \$10.78 per barrel (1978 dollars) (10).

Infrastructure expansion

Infrastructure investments for unit shale oil plants in sparsely populated areas are listed in Table 7-5, based on the employment estimates in Table 7-6 and the assumptions in Chapter 5, Section 8.

7.8 Primary and Secondary Employment

Table 7-6 gives estimated employment figures for unit oil shale plants during the peak construction and operational periods. It is assumed that 1.8 secondary (service) jobs are created for each primary position. Because the Green River area is sparsely populated, most of the work force will come from outside the area.

7.9 Demand for Community Services

Based on the standards in Chapter 5, Section 9, community service requirements needed to support the population directly and indirectly associated with a unit shale oil operation are presented in Table 7-7. Since most of the work force and their families will be new to the region, these figures approximate the actual additional services that will be required.

7.10 Reversible and Irreversible Commitment of Resources

The resources committed when an oil shale plant is built are similar to those for a coal gasification plant, but the magnitude of impacts resulting from land use will be much larger. In particular, the potential for deleterious effects to water quality is more severe, since several times as much waste will be handled. Unlike coal conversion plants in Eastern regions, shale oil facilities may consume a substantial portion of the available water supply.

7.11 Difficulties in Commercialization of the Conversion Processes

Despite large capital requirements, oil shale recovery will probably be economically viable by 1985. Research is underway in the remaining technical and environmental problem areas:

- A method of spent shale disposal which minimizes impacts on water quality, land use and esthetics.
- Determination and control of water contamination from mining and in situ processing.

TABLE 7-5

INFRASTRUCTURE DEVELOPMENT COSTS ASSOCIATED
WITH UNIT OIL SHALE PLANTS

	Peak Construction		Operation	
	Above Ground	Modified In Situ	Above Ground	Modified In Situ
Total employment	3,676	4,569	3,576	2,905
Total population	9,815	12,200	9,548	7,756
Investment in existing communities (million dollars)	29.4	54.9	28.6	34.9
Additional investment for new communities (million dollars)	14.7	18.3	14.3	11.6

Based on cost assumptions in *Synthetic Fuels Commercialization Program* which have been listed in Section 5.8.

TABLE 7-6
EMPLOYMENT FROM A UNIT SHALE OIL PLANT

Phase	Primary		Secondary		Total	
	Above Ground	Modified In Situ	Above Ground	Modified In Situ	Above Ground	Modified In Situ
Peak Construction	1313	1632	2363	2937	3676	4569
Operation (includes underground mining)	1277	1034	2299	1861	3576	2905

Source: *Synthetic Fuels Commercialization Program* (6).

TABLE 7-7

MAXIMUM ADDITIONAL DEMAND FOR COMMUNITY
SERVICES FOR A UNIT SHALE OIL PLANT

Service Category	Peak Construction		Operation ^(a)	
	Above Ground	Modified In Situ	Above Ground	Modified In Situ
Doctors				
Primary	8	11	8	6
Specialty	6	8	6	5
Hospital Beds	39	49	38	31
Dentists	4	6	4	4
Law Officers	20	25	19	16
Police Cars	4	6	4	4
Firemen	10	13	10	8
Teachers	67	84	65	53
K-6	67	84	65	53
7-9	34	42	33	27
10-12	34	42	33	27
Sanitary Landfill (acres)	39.2	49.1	38.1	31.3
Sewage Treatment (thousand gallons/day)	368	457	358	291
Water requirements (thousand gallons/day)	626	777	609	495

Based on assumptions in *Synthetic Fuels Commercialization Program* (6), which have been listed in Section 5.9.

- The availability of adequate water supplies for community, agricultural and industrial needs.
- The capability to handle the tremendous amounts of material processed by the industry. Each unit plant would process nearly 23 million tons of shale a year, and supply 1/4 of 1% of the nation's oil requirements for the year 2000. In contrast, the entire U.S. coal production in 1976 was about 600 million tons (8).
- A number of parameters, particularly those involving fracturing techniques, remain to be optimized (in situ and modified in situ processes).

Additional consideration in the development of an oil shale industry include:

- Minimization of the impacts of and establishment of adequate services for new communities in the developed areas.
- Expansion of railroads and pipelines.

7.12 Current status and selected process descriptions

Following the completion of a detailed design, the Colony Development Corporation scheduled the construction of the world's first commercial oil shale extraction plant for 1975. The project was suspended indefinitely, however, in the fall of 1974, because of the lack of guarantees and incentives for shale oil production.

The Paraho Development Corporation has also advanced its process to the brink of demonstration. Additional financial backing is currently sought. Two pilot scale retorts have operated. Under contract with the Navy, one is now producing 100,000 barrels of syncrude. Other oil shale processes are in advanced stages of development.

The major thrust of the DOE oil shale development program has been in the areas of in situ retorting, bench scale gasification, and supporting research, such as fracturing studies and environmental impact analyses. Successful development of in situ retorting could substantially increase recoverable reserves, reduce water requirements and mitigate environmental impacts. The research, funded at \$28 million in fiscal year 1978, is being coordinated by the Laramie Energy Research Center.

7.12.1 OCCIDENTAL (OXY) MODIFIED IN SITU PROCESS

Occidental Petroleum (OXY), Bakersfield, California, began work on the field testing of a modified in situ shale oil recovery scheme in 1972.

Research is continuing under a DOE contract received in 1977. Three research retorts, each 30 feet on a side and 72 feet high, were prepared and ignited. In 1974, OXY initiated the development of a commercial size retort in its commercial mine nearby.

The commercial mine is being developed because there is insufficient room at the head of Logan Wash (the research mine location) to permit a large mining operation, and because the research mine is located just below the Mahogany Ledge and too high for the construction of commercial size retort columns.

The first commercial size retort was ignited from the top on December 10, 1975. The burn was continued successfully until late June 1976 with a total production of 27,500 barrels of crude shale oil. Sustained combustion and temperature control was achieved by recycle of a portion of the retort gas. A second commercial size retort similar in dimensions to the first has now been prepared.

The modified in situ process for shale oil recovery consists of retorting a rubblized column of broken shale, formed by expansion of the oil shale into a previously mined out void volume. The OXY process involves three basic steps. The first step is the mining out of approximately 20 to 25 percent of the oil shale deposits (preferably low grade shale or barren rock), either at the upper and/or lower level of the shale layer. This is followed by the drilling of vertical longholes from the mined-out room into the shale layer, loading these holes with an ammonium nitrate-fuel oil (ANFO) explosive, and detonating it with appropriate time delays so that the broken shale will fill both the volume of the room and the volume of the shale column before blasting. Finally, connections are made to both the top and bottom and retorting is carried out.

A plan view of a typical commercial development based on the OXY scheme is presented on the next page. The commercial size rooms would be 120 feet to 160 feet square with a height determined by the height of the oil shale zone. The thickness of the walls between adjacent retorts depends on whether the rubblized chimney will be a totally load supporting mass by itself or whether the walls are required to serve as actual pillar supports. In the former case, a wall thickness of 20 feet is probably adequate since the walls only serve to physically separate the retorting chambers from one another. In the latter case, however, the dimensions of the walls will be significantly greater.

Both the size of the retorting chamber and the thickness of the walls have an important impact on the fraction of the cross section of the shale formation available for retorting. Thus large retorting chambers and thin walls are necessary for the optimum recovery of oil shale resources.

In the construction of the commercial size retort OXY plans mining at two levels. The upper mining level will be a complete heading at or near the top of the retort, and will serve as a base from which vertical longholes will be drilled for the loading of explosives. In the retorting process, combustion air will be supplied through the heading.

Retorting is initiated by heating the top of the rubblized shale column with the flame formed from compressed air and an external heat source, such as propane or natural gas. After several hours, the external heat source is removed and the compressed air flow is maintained, utilizing the carbonaceous residue in the retorted shale as fuel to sustain air combustion. In this vertical retorting process, the hot gases from the combustion zone move downwards to pyrolyze the kerogen in the shale below

OXY'S PROPOSED IN SITU MINING SCHEME

the zone, producing gases, water vapor, and shale oil mist which condense in the trenches at the bottom of the rubblized column. The oil production precedes the advancing combustion front by 30 to 40 feet. The crude shale oil and by-product water are collected in a sump and pumped to storage. The off-gas is composed of gases from shale pyrolysis, carbon dioxide from the decomposition of inorganic carbonate (primarily dolomite and calcite). Part of this off-gas is recirculated to control the oxygen level in the incoming air and the retorting temperature. The part of the off-gas not recycled will be burned in a turbine for electric power generation after hydrogen sulfide removal.

The off-gas resulting from the retorting process is the largest stream of air emissions from an in situ shale oil facility. A commercial-scale operation may produce several million cubic feet per minute. These gases have low heating values (on the order of 20 to 100 Btu/ft³); therefore, disposal by thermal oxidation requires relatively large quantities of supplemental fuel and is uneconomic. The hydrogen sulfide (H₂S) and ammonia (NH₃) can be removed by conventional techniques, but hydrocarbons in low concentrations present a major problem. Techniques for handling hydrocarbon emissions from in situ retorting need further development. One possible technique is to burn the off-gas in a turbine for electric power generation. This technology has not been fully developed, however, and requires further R&D effort.

Water is one of the major by-products of oil shale retorting and may be produced at a rate of one barrel per barrel of shale oil. The average flow rate, however, is expected to range from 10 to 20 percent of this rate for a typical oil shale commercial plant. A variety of organic and inorganic compounds that are present in the water need to be removed before the water can be reused or discharged. Several methods can be used to remove hazardous substances from the water, including lime scrubbing, volatilizing, by heating, and adsorption with activated carbon or ion-exchange resins.

To prevent the backfilling of natural groundwater into burned-out in situ sites, it may be desirable to reinject treated wastewaters from surface operations to repressure the aquifer. This may delay the ultimate circulation of influx groundwater. On the other hand, it may be that for some locations no significant deterioration of groundwater will result from backflooding. This will be true when the surrounding groundwater is unable to migrate at any appreciable rate because of the highly impermeable nature of the formation.

For a modified in situ process, mining and rubblizing require the removal of approximately 20 percent of the rock in a retort column. Assuming 20 gallons per ton of shale, a 50,000 barrel per day facility may produce about 20 million cubic yards of oil shale rock each year. The mined ore from this operation may or may not be processed in aboveground retorts. If it is, the retorted shale disposal requirement will be small. If it is not, the raw shale will be piled up at a disposal site, thus exposing large surface areas of unprocessed shale to the leaching effects of precipitation and melting snow. This may necessitate the application of leaching controls.

Subsidence of overlying formations can be expected to occur for retort roof dimensions greater than 100 ft. square, because the roofs become unstable at larger sizes. Therefore, subsidence must be properly monitored. Localized seismic damage may result from blasting activities conducted while rubblizing retort-chimneys. Seismic hazards include aboveground shaking and attendant surface-structure damage, rockslides

from unstable slopes, and underground structure collapse. Geohydrologic effects include disruption of preexisting patterns of groundwater movement with attendant depletion of aquifers and modification of recharge rates. The systems required to control or reduce these impacts depend on the characteristics of the selected site and vary from facility to facility.

Spent or retorted shale is the major waste product of modified in situ technology. The particle size of the spent shale can range from a fine powder to about 10 inches in diameter, and is usually discharged as a dry material. For disposal, larger sized materials will probably require crushing and the addition of water (10 to 20 percent by weight) to reduce fugitive dust emissions and aid in compacting disposal piles. Transport to the disposal area can be done several ways, including hooded belt conveyor, water slurry pipeline, pneumatic transport, or vehicle conveyance. (11,12,13)

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CHAPTER 8

TAR SANDS TO GAS AND OIL

8.1 Brief Technical Description

Tar sands are deposits of porous rock or sediments that contain hydrocarbon oils too viscous for extraction by conventional petroleum recovery methods. While total world deposits are estimated at between one and two trillion barrels, the United States has only 2-3% of this resource, or about 30 billion barrels. Estimates of the recoverable reserves range from 2.5 to 16 billion barrels (1).

The hydrocarbons, which are collectively referred to as bitumen, account for 9 to 16% (by weight) of the tar sands, which are usually some type of sandstone or dolomite. A deposit containing 14% is considered rich, and one barrel of bitumen can be extracted from 2.6 tons of tar sands of this quality. Each barrel has an energy content of 6.3×10^6 Btu. The sulfur content varies widely between different geographic locations but is near 0.5% in the major high quality deposits.

The vast majority of the resource (as much as 29 billion barrels) is located in Utah, although other large deposits in California, Kentucky, Alabama, New Mexico and Texas may be exploited. Smaller deposits are found in another 16 states (2).

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 8-1. Hot water extraction process.

Above ground processes

There are three types of processes used for extracting bitumen from tar sands. The GCOS plant uses the hot water extraction process shown in Figure 8-1. Steam hot water and sodium hydroxide are added, along with the tar sands, to a separator. The minerals sink to the bottom, but the bitumen tends to float on the surface, where it is skimmed off. It is then centrifuged to remove water and dissolved minerals, mixed with naphtha and sent to the upgrading facilities.

The solvent extraction process, shown in Figure 8-2, uses an organic liquid to dissolve the bitumen. The remainder of the process involves equipment for recovering the solvent from the bitumen and solid waste. This is essential if the process is to be economical.

As shown in Figure 8-3, the pyrolysis method is similar to oil shale retorting. The large organic molecules are decomposed by heating in the absence of oxygen. The smaller molecules are vaporized by the heat and flow from the coker to a condenser. The hydrocarbons not recovered in the coker are burned to supply process heat.

In situ recovery

The most promising in situ technique is an extension of underground coal gasification technology known as In Situ Reverse Combustion. The process is illustrated in Figure 8-4.

A combustion zone is started at the production well and travels from this well to the injection well. A compressor at the input well forces air into a reservoir and the air flows in a direction opposite to the combustion front. The air passes through the combustion zone and carries the cracked hydrocarbons and gases to the production well where it is withdrawn and passes through a condenser to separate the oil.

Upgrading

Once extracted, the bitumen must be upgraded in order to circumvent problems in handling and pipeline transport. The steps involved are shown in Figure 8-5 and are essentially the same as those for oil shale upgrading, discussed in Chapter 7, Section 1.

8.2 Quantity and Type of Primary Source

A unit tar sands conversion plant is taken as one producing 40,000 bbl/day (barrels per day) of (upgraded) syncrude (i.e., about 250 billion Btu/day) with an energy content of 6.3×10^6 Btu/bbl. The GCOS plant in Alberta requires 96,000 tons/day of tar sands to produce this amount. (Actual production is 50,000 to 55,000 bbl/day from 120,000 tons of tar sands.) Conversion plants in the United States will require even larger quantities, since U.S. resources are not as rich as the Athabasca deposits.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 8-2. Solvent extraction process.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 8-3. Pyrolysis "coking" extraction process.

Source: *Fossil Energy Research Program of the E.R.D.A. Fiscal Year 1978* (3).

Figure 8-4. In situ reverse combustion.

Source: *Energy Alternatives: A Comparative Analysis* (1).

Figure 8-5. Steps involved in upgrading bitumen to synthetic crude oil.

8.3 Quantity and Type of Other Resources Used for Energy

Water

Water requirements for the GCOS plant in Alberta are 7 million gallons per day. However, this figure cannot be used even as a rough estimate for processes other than hot water extraction. Other processes should use considerably smaller quantities, although no estimates are presently available.

Other

The additional resources used for energy production vary with the extraction method, but in most cases estimated quantities are not available. Hot water extraction also requires sodium hydroxide. Organic solvents, such as naphtha, methylchloroform, trichloroethylene or perchloroethylene, are used in solvent extraction processes, but since most of the solvent is recovered and recycled, only minimal amounts will be required as make-up. Hydrogen and process energy requirements can be obtained from the bitumen, rather than importing gas and electricity.

8.4 Environmental Control Processes

Particulate and sulfur oxides emissions from ancillary fuel combustion are controlled by the methods discussed in Chapter 5, Section 4. The concentrations of nitrogen and sulfur in the bitumen are reduced during the hydrogenation step of upgrading, with the necessary hydrogen generated on site from off gases. The reduced forms of nitrogen and sulfur, NH_3 and H_2S , are separated from the liquid and processed in ammonia and sulfur recovery units.

Water treatment methods and materials are discussed in 5-4.

8.5 Primary and Secondary End Products

The primary end product is 40,000 bbl/day of 6.3×10^6 Btu/bbl syncrude, which can be refined into all conventional petroleum products. Electricity beyond that needed on site (generated from by-product gases) and excess coke are possible secondary products. Sulfur and ammonia can be recovered from the upgrading off-gases and sold (300 tons of sulfur/day are produced by the GCOS plant in Alberta).

8.6 Residuals: Quantity, Type, Environmental Significance, Current Legislation

Although estimates of the quantities of residuals generated by tar sands operations are not available, the types, sources and effects may be similar to those from oil shale processing. Spent sand (from above ground processes) can be returned to the mining site, thereby minimizing topographic changes.

8.7 Process Economics

No economic estimates were found in this study for the production of oil from U.S. tar sands deposits. Such estimates are difficult without a conceptual design of a large-scale operation. It has been reported that the Syncrude plant in Alberta (129,000 barrels per day capacity) cost \$2.16 billion to construct (4).

Infrastructure expansion

Investment for infrastructure development in sparsely populated areas is given in Table 8-1. The employment estimates of Table 8-2 and assumptions listed in Chapter 5, Section 7 were used to obtain these figures.

TABLE 8-1
INFRASTRUCTURE DEVELOPMENT COSTS ASSOCIATED WITH A UNIT TAR SANDS PLANT

	Peak Construction	Operation
Total employment	8,680	3,810
Total population	23,200	10,200
Investment in existing communities (million dollars)	69.6	30.6
Additional investment for new communities (million dollars)	34.8	15.3

Based on cost assumptions in *Synthetic Fuels Commercialization Program* (5), which have been listed in 5.7.

TABLE 8-2
EMPLOYMENT FOR A UNIT TAR SANDS PLANT

Phase	Primary	Secondary	Total
Peak Construction	3100	5580	8680
Operation	1360	2450	3810

Source: GCOS and Syncrude literature.

8.8 Primary and Secondary Employment

The employment estimates presented in Table 8-2 were obtained by linear scaling of figures reported by GCOS and Syncrude (4,6). Although this would normally be expected to underestimate the actual requirements, technological advances which can be expected before commercial exploitation of U.S. resources, and the location of the resources in more accessible and temperate regions than are the Athabasca deposits, will permit less labor-intensive operations.

8.9 Demand for Community Services

Based on the standards presented in Chapter 5, Section 9, community service requirements for the total population associated with a unit tar sands plant are presented in Table 8-3. Since most of the commercially attractive deposits are in sparsely populated areas, these figures approximate the actual additional demand.

8.10 Reversible and Irreversible Commitment of Resources

The amount of land committed to a tar sands plant, and therefore the magnitude of land use impacts will be much greater than for other fossil fuel conversion processes due to the tremendous quantities of materials handled. Processing equipment will cover about 240 acres and a tailings (combined spend sand and process water) pond will cover another 2400 acres. Approximately 220 acres/year will be strip mined.* Land reclamation may be extremely difficult or impossible. In addition, the equipment, materials and energy consumed will be proportionately larger. In situ recovery would mitigate these effects.

Because tar sands deposits are not as abundant as coal or oil shale, development of the resource would remove its availability to future generations more rapidly. A single 40,000 bbl/day plant would consume 2 to 13 percent of the estimated recoverable resource (depending on whose estimate is used) in its 25 year life.

Bitumen on the surface of tailings ponds poses a serious hazard to migratory birds in the Athabasca region (4). The extent to which this will be a problem in the United States has not been determined.

8.11 Difficulties in Commercialization of the Conversion Processes

The major obstacles confronting commercial syncrude production from tar sands in the United States are:

- Conventional hot water extraction cannot be used with deposits that do not contain a water film between the bitumen and sand, as is the case in U.S.
- Relatively small quantities and low quality of the resource.
- Unfavorable economics compared to other conversion processes.
- In situ recovery, which may be more economically attractive, is a relatively new technology requiring several years of research before it can be applied.

TABLE 8-3
MAXIMUM ADDITIONAL DEMAND FOR COMMUNITY SERVICES FOR A UNIT TAR SANDS PLANT

Service Category	Peak Construction	Operation
Doctors		
Primary	19	8
Specialty	15	7
Hospital Beds	92	41
Dentists	12	5
Law Officers	46	20
Police Cars	12	5
Firemen	23	10
Teachers		
K-6	421	187
7-9	211	93
10-12	211	93
Sanitary Landfill (acres)	92	41
Sewage Treatment (million gallons/day)	2.3	1.0
Water Requirements (million gallons/day)	3.9	1.7

Based on assumptions in *Synthetic Fuels Commercialization Program* (5), which have been listed in 5-9.

These factors indicate that no commercial production will occur before 1990, and possibly for several years beyond.

8.12 Current status and selected process description

Great Canadian Oil Sands (GCOS), a subsidiary of the Sun Oil Company, has extracted tar sands commercially for ten years. A second and larger operation is scheduled for start-up in 1978 by Syncrude Canada, Ltd. Both facilities are located at the rich Athabasca deposits of Alberta.

In the United States, research is concentrating on in situ recovery, because the overburden on U.S. deposits is generally too thick for economical strip mining and underground mining techniques have not been developed. Pilot tests are being conducted by the Laramie Energy Research Center on the rich deposits near Vernal, Utah. In fiscal year 1977, \$1.4 million was allocated for this and supporting research.

8.12.1 IN SITU REVERSE COMBUSTION

DOE's Laramie Energy Research Center is conducting a series of laboratory and field experiments aimed at demonstration of the technical and economic feasibility of thermal processes for in situ extraction of the bitumen in U.S. tar sands.

In the In Situ Reverse Combustion Process a combustion zone is started at the production well and travels from this well to the injection well. A compressor at the input well forces air into the formation and the air flows in a direction opposite to the combustion zone. The air passes through the combustion zone and carries the cracked hydrocarbons and gases to the production well where it is withdrawn and passed through a condenser to separate the oil.

The greatest advantage of the in situ reverse combustion process is that the hydrocarbon products move through a heated area of the formation and thus are not affected by a strict viscosity limitation.

The most recent LERC field experiment was initiated on private land in Utah's Northwest Asphalt Ridge deposit on August 28, 1977. This experiment is testing the combination of reverse and forward in situ combustion in a small 40 by 120 foot 9-well line pattern (3 production and 6 injection wells). The reverse combustion process was applied to a thin portion of a 13-foot thick producing zone at a depth of 350 feet. The reverse combustion produced a portion of the bitumen and increased the mobility of the remainder, thus enhancing the applicability of the following forward combustion process. The reverse combustion process produced nearly 20 percent of the oil-in-place (estimated 400 barrels). The forward combustion process is expected to produce an additional 20 to 30 percent of the original oil-in-place.

Future field experiments are planned to demonstrate the economic feasibility of the combination in situ combustion process.

An initial Environmental Assessment for this project was prepared in 1974 and approved by the U.S. Bureau of Mines. An updated Assessment was prepared in late 1977. The main environmental concern is possible contamination of groundwater

systems by unrecovered hydrocarbons. At the project test site, however, all injection and production wells have been cased and cemented to prevent introduction of produced oil or gas into any but the test zone. (7,8,9)

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CHAPTER 9

MAGNETOHYDRODYNAMICS

9.1 Brief Technical Description

In conventional fossil fuel burning power plants, the combustion temperature approaches 4000°F, but materials limitations necessitate inefficient heat transfer to a working fluid (steam) at about 1100°F. A gas turbine, in which the combustion gases are the working fluid, performs more efficiently because it utilizes temperatures in the 2000°F range. The reciprocating Diesel engine also makes use of high temperature gases for efficient power generation.

Magnetohydrodynamics exploits high temperature gas energy in an unusual way. In open cycle MHD systems (illustrated in Figure 9-1) the combustion gases, at a temperature near 4400°F, are "seeded" with an ionizable salt, usually K_2CO_3 , and forced through a narrow channel so that there is a considerable amount of kinetic energy. A high strength magnetic field attracts free electrons to an electrode at the side of the channel. A circuit is provided, so that electrical energy is generated by movement of the combustion gas (the plasma) between the electrodes. An air preheater and conventional power plant then extract thermal energy remaining after expansion of the gases in the diffuser. Thus, the MHD unit provides a means of extracting additional useful energy from the same amount of fuel.

An additional benefit of the MHD generator is the virtual elimination of sulfur pollution by chemical reaction with the seed material. Most of the seed is regenerated, in order to minimize costs, producing fresh K_2CO_3 and a solid waste containing the sulfur and ash from the coal along with unrecovered seed.

An interesting feature in the MHD generator is the use of superconducting magnets. These magnets, which must be maintained at temperatures near absolute zero, obviate the high power consumption of conventional electromagnets. However, the magnets are located close to the highest temperature components of the system, and special cooling must be provided.

Another heat transfer problem arises from the need to preheat the combustion air to about 2000°F in order to attain the high flame temperature at which the gases ionize. (Alternatively, the oxygen content of the air can be enriched, but this is not presently economical.) The hot gases leaving the MHD generator provide a logical source of heat for the incoming air, but conventional heat exchanger materials are inadequate at these temperatures. Ceramic materials, which are not normally used in heat exchangers due to their low thermal conductivity, are being investigated as a replacement.

Other areas under investigation include the separation and recovery of seed material, electrode life and performance and the formation of nitrogen oxides.

Source: *Fossil Energy Research Program of the E.R.D.A. Fiscal Year 1978 (1)*.

Figure 9-1. Open cycle coal-fired MHD process.

Closed cycle MHD systems differ in that a working fluid is circulated through the system in a closed loop, much as steam is circulated in a conventional power plant.

9.2 Quantity and Type of Primary Source

The synthetic fuels produced by the conversion processes previously discussed could be used to generate electricity. An output of 250×10^9 Btu/day would be suitable for a conventional 1200 MWe power plant, and in order to allow comparisons, a unit MHD plant is taken as one with a 1200 MWe generating capacity. Due to its higher efficiency, the MHD facility will consume only 200×10^9 Btu/day. Although not technologically limited to a particular fossil fuel, American plants will burn coal, since it is the most abundant domestic resource. Quantities are given in Table 9-1 for eight ranks of coal.

9.3 Quantity and Type of Other Resources Used for Energy Conversion

Auxiliary energy

Energy is consumed by electrical equipment in the plant and represents a reduction of about 3.5 percent of the new power output (2).

Water

Water is used principally for removing waste heat by condensing steam leaving the bottoming turbine. Evaporative losses from the cooling tower are given in Table 9-1.

TABLE 9-1
RESOURCES CONSUMED IN A UNIT OPEN CYCLE MHD PLANT (a,b,c)

Region	Location	Type	Coal Bed	Coal Feed (tons/day)	Water Vaporized (MMgal/day)	Make-up K_2CO_3 (tons/day)
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	7,236	11.7	43.8
	Belmont Co., Ohio	Bituminous	Pittsburgh	7,656	11.6	64.4
	Jefferson Co., Ala.	Bituminous	Blue Creek	7,320	11.6	12.6
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	9,036	11.5	50.8
	Henderson Co., Ky.	Bituminous	No. 9	8,388	11.6	70.7
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	11,930	11.0	15.5
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	13,560	10.8	23.4
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	10,540	11.1	22.8

- a) Assumes a 50% overall thermal efficiency.
- b) Approximately 1000 Btu are removed in condensing steam leaving the bottoming turbine by each lb of water vaporized.
- c) Assumes 95% regeneration of seed.

9.4 Environmental Control Processes

The seed material, K_2CO_3 , reacts with sulfur in the combustion products and is recovered as K_2SO_4 . In order to minimize costs, most of the seed must be regenerated. The chemistry of this regeneration has not yet been established (2); therefore, the most economical recovery efficiency cannot be determined. Table 9-1 gives the amount of make-up seed required assuming 95% regeneration.

Sulfur removal by reaction with the seed material not only obviates the need for flue gas desulfurizers, but also allows essentially complete elimination of sulfur pollution. In contrast, flue gas desulfurizers rarely achieve consistent removal efficiencies greater than 90%.

EPA standards will require 99.5% control of particulates (2). This can be accomplished by the relatively inexpensive and well established techniques discussed in Chapter 5, Section 4.

Nitrogen oxides are controlled by two stage combustion. In the first stage, combustion occurs in an oxygen deficient environment (typically 95% of the stoichiometric oxygen requirement is supplied). This limits the amount of oxygen available for reaction with nitrogen. The balance of air is supplied after the temperature has been reduced. The equilibrium concentration of NO_x is considerably less in this second stage.

9.5 Primary and Secondary End Products

A unit MHD plant will have an electrical generating capacity of 1200 MWe and will be used for base load power generation, because of its high capital and low operating costs (see Section 9.7).

The chemistry of seed regeneration is not well developed (2), and it may become possible to extract a saleable sulfur by-product. Until this has been demonstrated, the sulfur is best regarded as a waste requiring disposal.

9.6 Residuals: Quantity, Type, Environmental Significance, Current Legislation

In general, smaller quantities of air emissions, solid wastes and thermal pollution will be produced by MHD power plants than by conventional power plants, since MHD power generation consumes less fuel per unit of electricity.

Air emissions

The Department of Energy will begin environmental assessments of MHD in 1979. No quantitative estimates of air pollutants are likely to be available until these studies have been completed.

Solid waste

The quantities of solid waste for the eight ranks of coal presented in Table 9-2 assume 100% recovery of ash, 5% loss of seed material (as K_2SO_4) and that seed regeneration results in the formation of elemental sulfur.

9.7 Process Economics

Preliminary economic projections were made by Westinghouse and General Electric as part of the Energy Conversion Alternatives Study (ECAS; References 2 and 3). Assuming operation at 65% of capacity, a labor rate of \$10.60/hour and a cost of fuel of \$0.85/10⁶ Btu, the following results were obtained for a 1200 MWe plant burning 3.9% sulfur, bituminous coal:

- Capital Cost:
 - Westinghouse: \$797 million (20.1 mills/kwh).
 - General Electric: \$1239 million (33.2 mills/kwh).

TABLE 9-2
RESIDUALS AND BY-PRODUCTS FOR OPEN CYCLE MAGNETOHYDRODYNAMICS (a)
(Tons/day)

Region	Location	Type	Coal Bed	Total Coal Used (tons/day)	Ash	Unrecovered Seed	Sulfur
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	7,236	600	55	192
	Belmont Co., Ohio	Bituminous	Pittsburgh	7,656	666	82	283
	Jefferson Co., Ala.	Bituminous	Blue Creek	7,320	696	16	55
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	9,036	614	64	223
	Henderson Co., Ky.	Bituminous	No. 9	8,388	1,024	89	310
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	11,930	703	19	68
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	13,560	1,000	29	103
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	10,540	1,360	29	100

a) Assumes 95% regeneration of seed and elemental sulfur produced as a by-product.

- Operation and maintenance, including coal costs:
 - Westinghouse: 6.8 mills/kwh.
 - General Electric: 9.2 mills/kwh.
- Total cost of electricity:
 - Westinghouse: 26.9 mills/kwh.
 - General Electric: 42.4 mills/kwh.

Although Westinghouse allocated more for the major components with uncertain costs - superconducting magnets, recovery heat exchangers and seed regeneration equipment - General Electric's overall capital investment is over 50% higher, which accounts for the major difference in the predicted cost of electricity.

Promising systems were identified by this part of the ECAS study. More accurate estimates for these systems should be obtained for Phase II, but the actual economics

are contingent on the costs of the major components mentioned above, which are currently under development.

Infrastructure expansion

Investment for infrastructure development in sparsely populated areas is given in Table 9-3. The employment estimates of Table 9-4 and assumptions listed in Chapter 5, Section 7 were used to obtain these figures.

9.8 Primary and Secondary Employment

Although no estimates have been published for employment at MHD plants, it is likely that they will not differ drastically from conventional fossil fuel fired power plants. The projections listed in Table 9-4 do not take into account the construction

TABLE 9-3
INFRASTRUCTURE DEVELOPMENT COSTS ASSOCIATED
WITH UNIT MHD POWER PLANTS

Category	Peak Construction	Operation	
		Mine Mouth (a)	Other (b)
Total employment	2800	1725	280
Total population	7480	4610	750
Investment in existing communities (million dollars)	22.4	20.7	3.4
Additional investment for new communities (million dollars)	11.2	6.9	1.1

- a) Assumes 516 surface miners employed at nearby mine.
- b) Plants not located near the coal mine.

Based on cost assumptions in *Synthetic Fuels Commercialization Program* (4), which have been listed in 5.7.

TABLE 9-4
EMPLOYMENT FOR A UNIT MHD POWER PLANT (a,b)

		Primary	Secondary	Total
1. Peak Construction		1000	1800	2800
2. Plant Operation and Maintenance		100	180	280
3. Coal Mining				
● Appalachia	Monongalia Co., W.V.			
	- Underground	1064	1915	2979
	- Surface	476	857	1333
	Belmont Co., Ohio			
	- Underground	1158	2084	3242
	- Surface	516	929	1445
● Eastern Interior	Jefferson Co., Ala.			
	- Underground	1099	1978	3077
	- Surface	491	884	1375
● Eastern Interior	Fulton Co., Ill.	478	860	1338
	Henderson Co., Ky.	354	637	991
● Powder River	Campbell Co., Wyo.	207	373	580
● Fort Union	Mercer Co., N.D.	308	554	862
● Four Corners	San Juan Co., N.M.	207	373	580
Total During Operation		Minimum		860
		Maximum		3522

a) 328 operation days per year (90% stream factor).

b) Based on the following productivity rates for miners (tons/person-day):

Appalachia		Eastern Interior	87
Underground	11.2	Powder River	100
Surface	29.7	Fort Union	100
		Four Corners	82

Sources: Construction and operating employment: Telephone conversation with Richard Werner (Northeast Utilities).
Mining employment: *Synthetic Fuels Commercialization Program* (4).

of railroads, transmission lines or roads, since these will be a function of the individual sites. Included in the table are the number of miners employed for supportive coal mining, although the plant will not necessarily be located near the mine.

9.9 Demand for Community Services

Community service requirements for the population directly and indirectly associated with a unit MHD plant are presented in Table 9-5, based on the employment projections in Table 9-4 and the standards given in Chapter 5, Section 9. The requirements were determined for plants located both near to and distant from the mine.

9.10 Reversible and Irreversible Commitment of Resources

A unit MHD plant will occupy about 200 acres, excluding land for extensions of roads, railroads and transmission lines.

The impacts on resources are similar to those discussed in Chapter 5, Section 10 with the following caveats:

- Air quality will probably not be adversely affected, except possibly in those areas where photochemical smog or nitrogen oxides already pose a problem.
- Population impacts may be significant during the construction phase but will be minimal during the operating life of the plant, except in very sparsely populated areas.
- The magnitude of impacts resulting from mining and other land use will be less than for other conversion processes.

9.11 Difficulties in Commercialization of the Conversion Processes

Open cycle MHD appears to be both economically and environmentally attractive, but it cannot be commercialized until several technical questions are resolved. Some of the components and subsystems have no previous applications and therefore must be tested and integrated with the remaining equipment. These include:

- Air preheaters: heat transfer occurs at temperatures approaching 4000°F in a corrosive and erosive environment.
- Electrode modules: the materials used must be able to withstand large thermal gradients created by the high heat fluxes, temperatures in excess of 4400°F, Mach numbers on the order of 0.75, and the presence of slag and seed, which will be deposited on the electrodes if they are cooled to prevent other problems. A high electrical conductivity is, of course, another important criterion.
- Superconducting magnets: the optimum efficiency will depend not only on their power consumption, but also on the proximity to the high temperature components of the generator and amount of thermal insulation.

TABLE 9-5
MAXIMUM ADDITIONAL DEMAND FOR COMMUNITY
SERVICES FOR UNIT MHD POWER PLANTS

Service Category	Peak Construction	Operation	
		Mine Mouth (a)	Other (b)
Doctors			
Primary	2	1	0
Specialty	2	1	0
Hospital Beds	11	7	1
Dentists	1	1	0
Law Officers	6	3	1
Police Cars	1	1	0
Firemen	3	2	0
Teachers			
K-6	51	32	5
7-9	26	16	3
10-12	26	16	3
Sanitary Landfill (acres)	11	6.9	1.1
Sewage Treatment (thousand gallons/day)	280	173	28
Water Treatment (thousand gallons/day)	476	293	48

- a) Assumes 516 surface miners employed at nearby mine.
b) Plants not located near the coal mine.

Based on assumptions in *Synthetic Fuels Commercialization Program* (4), which have been listed in 5.9.

- Seed regeneration: this remains to be technically demonstrated, and several years of developmental research will follow.

9.12 Current status and selected process description

Open cycle magnetohydrodynamics (MHD) appears to be an economically and environmentally attractive way to use coal. However, the technology is far from commercialization. The DOE research program, which is funded at \$50 million in FY 1978 is divided in three phases. Phase I will focus on testing of components and subsystems in a 50 MW (thermal) Component Development and Integration Facility (CDIF). Construction of the CDIF is scheduled for completion in late 1978.

The CDIF will also provide basic data for Phase II, the design and operation of a pilot scale (250 MW thermal) Engineering Test Facility (ETF). Operation of the ETF during the mid-1980's will test selected systems at commercial operating durations (1000 to 2000 hours).

Phase III includes the design and operation of a commercial scale demonstration plant in the 1990's.

Closed cycle MHD power systems are at an even earlier stage of development, addressing basic feasibility issues, particularly the development of suitable heat exchangers. Funding in 1978 is less than 2 percent of the MHD program.

Because of the early technological status of MHD power systems, only very limited commercial use is likely in this century.

9.12.1 OPEN-CYCLE COAL-FIRED

The most popular method of MHD conversion processes under development at the present time is the Open-Cycle Coal-Fired Magnetohydrodynamics Process. This process uses combustion gases to convert heat to electricity.

DOE's program goal is to produce a commercially acceptable coal-fired utility system using a combined MHD/steam power plant. To achieve this goal, two major interim objectives must be achieved: the first, to successfully test MHD components and subsystems and then to scale them up and integrate them into system tests; the latter to be conducted in the pilot-scale Engineering Test Facility (ETF), which is planned for operation in the mid-1980's; the second, to develop and operate a commercial-scale demonstration MHD power plant by the 1990's, fueled by coal, in an environmentally acceptable manner. Development of MHD technology will also continue in order to improve the performance, reliability, and benefits of MHD commercialization. These objectives support the current national energy goals.

In the open-cycle coal-fired system the compressed air heated to 4,500° to 5,000°F is used to burn the coal producing the combustion gases. This hot gas is subsequently seeded with particles of potassium. When these particles vaporize they ionize, or electrically charge, the gas which is then passed through a channel lined with electrodes. These electrodes collect and store the direct current. After this the gas is cleaned and used to power steam generators, thus producing conventional steam generated electricity.

* Air can be preheated by exhaust gases or heated separately.

OPEN-CYCLE MHD GENERATOR

There are difficulties with MHD development because of the extremely high temperatures used during the process. Also a high flame temperature is necessary to maintain a high electrical conductivity and a high conversion efficiency in open cycle MHD generators. As gas temperatures drop below 3,600°F conductivity falls to a point that MHD electrical power generation is uneconomical. (5,6)

Environmentally, the emissions of sulfur oxides from an MHD facility are inherently less than from conventional coal-fired boilers because of the use of potassium as a seed material. The potassium reacts chemically with sulfur. The overall environmental impacts of MHD will be less than those of conventional combustion because of the high conversion efficiencies associated with the technology. Other environmental concerns under study include:

- Increased nitrogen oxide emissions resulting from high operating temperatures;
- Development of waste management methods; and
- Potential effects of high-strength magnetic fields on humans. (7,8)

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CHAPTER 10

COAL OIL SLURRY

10.1 Brief Technical Description

In the U.S. during the 1960's many coal-fired utility and industrial power plants were converted to oil to meet higher sulfur pollution standards. It is now desired that some of these plants (and even plants originally designed to consume oil and gas) be converted to coal, often with flue gas desulfurization units installed. One relatively simple way to approach the problem is to grind the coal to a powder and mix it with oil so that the mixture (or "slurry") can be burned in the oil burner (Figure 10-1).

Once the mechanical details are perfected, the coal-oil slurry should reduce U.S. dependence on foreign oil. Process efficiencies will be somewhat less, since the flue gas desulfurizers require 0.5 to 1 percent extra energy to reheat the flue gas so that it will rise up the stack. Pollution levels then will be unaffected by a switch to the part coal feed, although more particulates and sulfur will be generated. The particulates will continue to be removed by electrostatic precipitators, which may have to be enlarged. The flue gas desulfurizers can be expected to remove 60 to 85 percent of the sulfur in the combined fuels, making about 2.5 times the weight of the recovered sulfur in gypsum (dry) for disposal and requiring about 1.6 times its weight in limestone (or about the same weight in unslaked lime) when "throwaway" processes are used for sulfur recovery.

10.2 Quantity and Type of Primary Source

Coal oil mixtures will be applied by retrofitting existing oil fired industrial and utility boilers and furnaces. In order to facilitate meaningful comparisons between this technology and those previously discussed, plants considered here are 1200 MWe power generating facilities.

Such a plant will require an input of about 250×10^9 Btu/day (which is the output of the unit synthetic fuels plants). The current DOE goal is a substitution for 50% (by weight) of the oil by coal (2). Achievement of this goal is assumed in the feedstock requirements listed in Table 10-1.

10.3 Quantity and Type of Other Resources Used for Energy Production

Water

Cooling water consumption, predominantly for steam condensation, in electric generating plants is listed in Table 10-1.

10.4 Environmental Control Processes

In many instances, retrofitting boilers to burn a part coal feed will require larger scrubbers and electrostatic precipitators. The criterion used will be their ability to meet applicable air quality standards. Table 10-1 includes a listing of the amount

Source: *Fossil Energy Research Program of the E.R.D.A. Fiscal Year 1978*

Figure 10-1. Coal oil slurry preparation.

of lime consumed by a scrubber which removed 90% of the SO_2 in the exhaust gas, again assuming that the boiler is fired on a mixture of half coal, half No. 6 fuel oil.

10.5 Primary and Secondary Products

The capacity of a unit plant has been taken as 1200 MW of electric power. Saleable by-products could be obtained by using certain flue gas scrubbing systems (see Chapter 5, Section 4), but systems producing a waste sludge are presently more commonly used.

TABLE 10-1
RESOURCES CONSUMED IN A UNIT COAL OIL MIXTURE FACILITY (a,b)

Region	Location	Type	Coal Bed	Coal (tons/day)	No. 6 Oil (bbl/day)	Water (MM gal/day)	Lime ^(a) (tons/day)
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	3,880	22,800	17.5	294
	Belmont Co., Ohio	Bituminous	Pittsburgh	3,970	23,400	17.5	392
	Jefferson Co., Ala.	Bituminous	Blue Creek	3,900	22,900	17.5	133
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	4,240	24,900	17.4	304
	Henderson Co., Ky.	Bituminous	No. 9	4,120	24,200	17.5	406
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	4,660	27,400	17.3	140
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	4,840	28,500	17.3	165
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	4,480	26,300	17.4	171

- a) Assumes half coal, half fuel oil mixture (by weight) and a 39% overall thermal efficiency.
- b) Approximately 1000 Btu are removed in steam condenser for each lb of water vaporized.

10.6 Residuals

Air emissions and solid wastes have been calculated assuming 90% SO₂ and 99% particulate removal efficiencies. The results are listed in Table 10-2. The plant will have no effluents to surface or ground waters, if sludge is disposed in lined ponds.

10.7 Process Economics

Retrofitting will cost on the order of \$1 million. Except for differences in fuel and pollution control equipment operation expenses, there will be a negligible impact on operating and maintenance costs. It is unlikely then that there will be any significant change in the cost of electricity.

TABLE 10-2
AIR EMISSIONS AND RESIDUALS FOR A UNIT COAL OIL MIXTURE POWER PLANT (a,b)
(tons/day)

Region	Location	Type	Coal Bed	SO ₂	Particulates	NO _x	HC	CO	Aldehydes	Ash	FGD Sludge
Appalachia	Monongalia Co., W.Va.	Bituminous	Pittsburgh	20.8	2.6	27.1	0.59	2.0	0.010	257	548
	Belmont Co., Ohio	Bituminous	Pittsburgh	29.6	2.8	27.7	0.61	2.0	0.010	277	731
	Jefferson Co., Ala.	Bituminous	Blue Creek	6.1	3.0	27.2	0.60	2.0	0.010	297	248
Eastern Interior	Fulton Co., Ill.	Bituminous	No. 6	21.1	2.3	29.6	0.65	2.2	0.011	228	567
	Henderson Co., Ky.	Bituminous	No. 9	30.7	4.0	28.8	0.63	2.1	0.010	396	757
Powder River	Campbell Co., Wyo.	Sub-bituminous	Wyodak	5.5	2.2	32.5	0.71	2.4	0.012	218	261
Fort Union	Mercer Co., N.D.	Lignite	Uncorrelated	7.5	2.9	33.8	0.74	2.5	0.012	287	308
Four Corners	San Juan Co., N.M.	Sub-bituminous	Composite	8.7	4.6	31.3	0.69	2.3	0.011	455	319

- a) Assumes half coal, half fuel oil mixture (by weight) and a 39% overall thermal efficiency.
- b) EPA *Compilation of Air Pollutant Emission Factors* used to determine air emissions. Control efficiencies of 99% for particulates, 90% for SO₂ and 25% for NO_x assumed.

Infrastructure expansion

As explained in the following two sections, there will be no need to expand the community infrastructure.

10.8 Primary and Secondary Employment

Impacts on employment will be minor and confined almost entirely to the retrofit stage.

10.9 Demand for Community Services

Because the modification of oil fired equipment to burn a coal oil mixture has minimal employment implications, it will be handled by local people and will not create any additional demand for community services.

10.10 Reversible and Irreversible Commitment of Resources

The most noticeable impact on resources that coal oil mixture will have is a reduction in the number of dollars committed to oil producing nations. Each 1200 MW plant converted to 50% coal will cut oil consumption by about 12,000 to 17,000 bbl/day, which might be viewed as a reduction in imports.

There will be some impacts on resources caused by the additional coal mining created. This is discussed in Chapter 5, Section 10.

10.11 Difficulties in Commercialization of the Conversion Process

This technology incorporated no major new technical ideas and will not need the lengthy development program inherent in the synthetic fuels projects. Economic impacts are more benign than detrimental, and environmental impacts can be effectively controlled. Widespread applications will probably begin in the early 1980s.

10.12 Current Status

Retrofitting oil-fired furnaces, steam generators and process heaters to burn coal is economically unattractive. However, pulverized coal can theoretically be substituted for a portion of the oil by forming a slurry and using a somewhat modified burner in the otherwise unaltered equipment, thereby minimizing capital investment.

A project initiated in 1976 is investigating the extent to which this retrofit technology can be practically implemented. In fiscal year 1978, \$7.0 million was allocated. Prototype will be tested on 100 and 700 HP water-tube boilers at the Pittsburgh Energy Research Center (PERC).

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CHAPTER 11

DIRECT COMBUSTION

11.1 Brief Technical Description

Direct combustion of coal is the major source of energy for most U.S. electrical power plants. In direct combustion, pulverized coal is fed to the burners of power plant boilers. Here it is combusted with air to produce heat which, in turn, produces steam to drive electric generating turbines.

The use of coal in direct fired industrial processes is an old technology and has wide spread applicability as a steam boiler fuel, in firing kilns, furnaces, and heaters. Over the years, the basic technology for firing coal has not changed to a large degree but minor changes in design and upgrading of materials have increased efficiency and reduced maintenance. During the past two decades, the direct use of coal in steam generation and heating declined from 14 percent in 1965 to 4 percent in 1972. This trend has been reversed in recent years as evidenced by orders for new coal fired generating units and conversion of existing equipment from oil and gas to coal. This trend will continue in the future as the federal government forces conversion of existing gas and oil fired equipment and further bans use of these fuels in future units.

Direct combustion of coal can provide a viable alternative to oil and gas for steam generation and some heating requirements and can ensure uninterrupted fuel supplies for the process industries. Unfortunately, selecting boilers, firing methods, and matching coal characteristics to meet process requirements is a complex task even with the relatively small number of feeding and firing methods available. A complete understanding of all the parameters which must be considered is essential in properly selecting equipment and methods for direct combustion of coal.

Generally speaking, there are two methods of burning coal; in suspension or in a fuel bed. In fuel bed firing, coal is pushed, dropped, or thrown on a grate in the high temperature region of a furnace by a device called a stoker. Fuel beds have historically provided the most economical method for burning coal in almost all industrial boilers rated less than 100,000 lb/hr of steam.

Suspension firing involves blowing pulverized coal into the surface box where rapid mixing of the coal particles with air at high temperature results in combustion of the coal particle and the resultant release of heat. Suspension firing has been generally found to be more economical for installations with capacity in excess of 100,000 pounds of steam per hour.

The use of either system for steam generation or process heat must be based on the particular application, cost analysis for both systems and coal type availability.

The combustion of coal is more difficult than the combustion of other fossil fuels. Its use involves equipment for: handling, size reduction, ash disposal, dust control, and sootblowing. Coal combustion accounts for the major portion of air, water, and solid waste emissions from the electric utility industry. (1,2,3,4)

11.2 Quantity and type of primary source

External combustion systems (boilers) produced 1419×10^6 MWh of electricity in 1974 from an installed capacity of 337,000 MW for an unusually low yearly average load factor of 48 percent. In previous years the load factor was 50 to 55 percent. Comparison of the fuel consumed to the electricity produced yields a 1974 heat rate of 10,420 Btu/KWh, equivalent to a heat-to-electricity efficiency of 33 percent. Table 11-1 summarizes the full capacity, consumption and production for external combustion in 1974.

TABLE 11-1

EXTERNAL COMBUSTION CAPACITY, CONSUMPTION AND PRODUCTION, 1974

	Capacity MW	Fuel Consumed 10^{12} Btu	Electricity generated 10^6 MWh
Coal	198,300	8,502	835.0
Oil	66,700	3,039	281.0
Gas	72,000	3,257	305.0
Total	337,000	14,798	1419.0

11.3 Type of other resources used for energy

Cooling water for steam condensation is utilized in electric generating plants.

11.4 Environmental Control Processes

Determination of actual pollutants as a result of installation of direct coal combustion equipment is dependent on the design of installation and the exact characteristics of the coal to be burned. Pollution control requirements are also dependent on federal, state, and local site standards.

11.5 Primary Products

The direct combustion of coal provides an alternative to oil and gas for steam generation, heating requirements, and insures uninterrupted fuel supplies for the process industries.

11.6 Residuals

Residuals for a coal combustion facility include air emissions, benzene soluble organics, particulate polycyclic organic material, and numerous trace elements. In addition to these are ash, water and solid wastes including lime and sludge.

11.7 Process Economics

The American boiler manufacturers associations projects that coal fired boilers will take at least 33 percent of the future boiler market as opposed to a historical rate of about 10 percent. This trend will continue in the future as the federal government forces conversion of existing oil and gas fired equipment and bans the use of these fuels in future units.

11.8 Primary and Secondary Employment

There will be no adverse impacts on employment. If a large number of plants are built beneficial impacts will result in the creation of new jobs and a lowering of the unemployment rate.

11.9 Demand for Community Services

Unless there is a demand for construction of many plants in one general area, there will be no need for additional services as the demand for personnel and labor will be handled by local people.

11.10 Reversible and Irreversible Commitment of Resources

There will be some impacts on resources caused by the additional coal mining created. This is discussed in Chapter 5, Section 10.

11.11 Difficulties in Commercialization of the Conversion Process

The general process is an old technology, which has been in commercial use for many years. Only minor changes in design and upgrading of materials is expected for future development.

11.12 Current Status and Selected Process Description

11.12.1 FLUIDIZED BED BOILER

The objective of the Fluidized-Bed Boiler Process is to design, construct, test and evaluate a pollution free method of burning high-sulfur content or slagging coals without excessive maintenance problems, under practical electrical utility conditions. In this process crushed coal and limestone combined with air are burned in a series of cells to produce steam which powers the generators. The limestone acts as a sorbent for any sulfur dioxide produced from the coal combustion.

The Fluidized-Bed Boiler Process was developed by Pope, Evans and Robbins, Inc. for the Monongahela Power Company's facility located at Rivesville, West Virginia. Initial light-off of the boiler with coal was successfully accomplished on December 7, 1976. Operation and testing of the pilot plant to demonstrate applicability of the multicell fluidized-bed for steam-electric power generation will extend through 1978.

The Rivesville facility is the first major step toward the commercial-size central power program. The combustor for Rivesville represents a building block for a scaleup to 200 MW_e and eventually to 800 MW_e.

The West Virginia pilot plant has a capacity of 336 tons per day of coal. Limestone and air are also feedstocks in this process. The effluents are stack gas, ash and sorbent.

The multicell fluidized-bed boiler consists of four adjacent combustion cells. The three primary cells (A, B, and C) operate at 1,550°F while the carbon burnup cells (D) operates at up to 2,000°F. Boiler tubes are arranged in horizontal bundles to enhance bed fluidization. Each of the four cells has economizer tubes in the upper convection region, which is heated by exhaust gases. The three primary cells have boiler tubes immediately above the fluidized bed section, and cell C has boiler tubes deep within the bed. Cells A and B both have superheater tubes immersed deeply into the bed region. This fluidized-bed boiler will produce approximately 300,000 lbs. of steam per hour at a temperature and pressure determined by the requirements of the boiler installation site.

Crushed coal and limestone are supplied to the system by weight hoppers and blown into the combustor unit with a stream of air. Coal and limestone are fed to cells A, B, and C at a 4:1 weight ratio. Unburned carbon supplied by the exhaust cyclone separator above the primary cells is fed to the carbon burnup cell. Air for bed fluidization is supplied to the burner cells by a common plenum. A 3 percent oxygen excess is maintained in the primary cells, and a 5 percent excess of oxygen is maintained in D. The exhaust gas cleanup system is comprised of cyclone separators trailed by an electrostatic precipitator. (3,4,5)

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CHAPTER 12

RESOURCES AND SITES: EAST, CENTRAL, WEST

12.1 The Resources: Summary

The major use of fossil energy resources stems from oil and gas. Until recently, because of their relatively low price, abundance, ease of handling and cleanliness, the utilization of these two resources has been desirable. As domestic production has had a harder time keeping pace with demand, however, and as foreign imports have increased, reliance on energy from alternate sources such as coal, oil shale and tar sands is becoming more attractive.

For coal, synthetic fuels can be produced through liquefaction and gasification. Essentially this involves breaking down high molecular weight hydrocarbon groups into lower molecular weight compounds. For oil shale and tar sands, extraction involves first making the "oil" or syncrude, as it is called, "flow" by heating in some manner the rock in which the oil and/or tar are contained. The oils are essentially locked up in the form of bitumen or kerogens, which are waxy solids. Synthetic "crude" is then refined in the same manner as conventional oil. Chapter 2 reviews the distribution of coal, oil shale, and tar sands in the lower 48 states.

Most of the eastern U.S. energy development centers around the Appalachian Coal Region. This area extends about 800 miles from northern Pennsylvania to Western Alabama in a mountainous topography. The region includes portions of the states of Pennsylvania, Maryland, Virginia, West Virginia, Ohio, Tennessee, Kentucky and Alabama.

The greatest portion of coal in the central states runs through central and southern Iowa, northwestern Missouri, eastern Kansas and Oklahoma, north-central and eastern Texas. Most of the coal in this area is medium and high volatile bituminous coal. The exception to this is eastern Texas which has scattered areas of lignite and brown coal.

Energy resources in the west include significant amounts of coal, oil shale, and tar sands. Bituminous coals are found in the states of Montana, Wyoming, Utah, Colorado, Arizona, and New Mexico. Lignite coal is located in eastern Montana, Western North Dakota and the northwestern corner of South Dakota. Tar sands (oil sands) are located in Utah and the bulk of the U.S. oil shale reserves are located in the Green River formation in Colorado, Utah and Wyoming.

12.1 Selection of Settings to be Described

Nine sites were selected as typical case studies to demonstrate the SELECS methodology, presented in Volume I. Each case study consists of a site, an energy conversion technology, and a specific process.

Each site was classified by geographic region (Eastern, Central, and Western) and by population domain (Urban, Suburban, and Rural). In terms of the provinces described earlier in Chapter 2, "Eastern" corresponds to this Eastern Province; "Central" corresponds to the Interior Province and Gulf Province; and "Western" corresponds to the Northern Great Plains Province, the Rocky Mountain Province, and the Coast Province. The domain classification is based on municipal population: Urban, greater than 100,000; Suburban, 25,000 to 100,000; and Rural, less than 25,000.

The next qualification for site selection was based on availability of feedstock with regard to potential demands for the synthetic fuel product. After the location of feedstock sources in each of the three geographic regions, selections of settings were made, based only on population (domain classification) and proximity to feedstock. Table 12-1 shows the sites selected within their "Region-Domain" classification. The geographic location of the nine selected sites is shown in Figure 12-1.

12.3 Selection of Conversion Technology and Processes

The selection of a technology for each of the nine selected sites was based primarily on the type of feedstock available. In some cases, consideration was given to probable local demand for the conversion products; in others, it was assumed that the end products would go to distant markets. Once a conversion technology was selected for each site, there remained only the designation of a specific conversion process to complete the nine case study descriptions.

Processes were chosen based on applicability to the DOE research program, availability of data, and the time horizon to commercial viability. A matrix illustrating the nine completely defined case settings is given in Table 12-2. Any considerations beyond this level of definition were left for the proposed impact methodology to evaluate.

12.4 Approach to Description of Setting

A common outline for the characterizations and accumulations of baseline data for each setting is shown in Table 12-3.

The outline implies that a defined energy conversion facility and process will be evaluated, based on its effects on local demographic, land-use, economic and social characteristics, and environmental qualities. The description under each of these broad categories helps to define the categories.

In general, Eastern areas offer abundant water supplies and diverse labor markets, but are restrictive with regard to land availability and environmental quality (air and water) regulations. Western areas have fewer problems with land availability, but are often plagued with restrictive water supplies and lack of trained labor. Environmental nondegradation policies and new source standards may impose worthwhile but expensive restrictions on location and operational characteristics of energy conversion facilities. The Central areas can range between the problems and advantages of both regions.

TABLE 12-1
THE NINE SELECTED SITES

Eastern	
• Urban	Pittsburgh, Pennsylvania
• Suburban	Charleston, West Virginia
• Rural	Jackson, Ohio
Central	
• Urban	Kansas City, Missouri
• Suburban	Bloomington, Illinois
• Rural ^a	
Western	
• Urban	Bismarck, North Dakota
• Suburban	Farmington, New Mexico
• Rural	Rawlins, Wyoming & Vernal, Utah ^a

^aIt was decided to demonstrate a tar sands technology in a Central Rural Area in Kansas, but a concentrated feedstock was not available. A second Western Rural setting, Vernal, Utah, was chosen because of its proximity to Asphalt Ridge, the richest tar sand deposit in the U.S.

Figure 12-1. Geographic Location of the Nine Selected Sites.

TABLE 12-2
THE NINE SELECTED CASE STUDIES

Type	Region		
	EAST	CENTRAL	WEST
URBAN	Pittsburgh, PA	Kansas City, MO	Bismarck, ND
	<ul style="list-style-type: none"> • Above ground • Bituminous coal • COGAS 	<ul style="list-style-type: none"> • Above ground • Bituminous coal oil slurry • Electric power production 	<ul style="list-style-type: none"> • Above ground • Lignite • Donor solvent liquefaction
SUBURBAN	Charleston, WV	Bloomington, IL	Farmington, NM
	<ul style="list-style-type: none"> • Above ground • Bituminous coal • Solvent refined coal 	<ul style="list-style-type: none"> • Above ground • Bituminous coal • MHD combined cycle • Electric power production 	<ul style="list-style-type: none"> • Above ground • Sub-bituminous coal • Synthane gasification
RURAL	Jackson, OH	Vernal, UT ^a	Rawlins, WY
	<ul style="list-style-type: none"> • In situ gasification • Bituminous coal • Above ground methanation 	<ul style="list-style-type: none"> • Above ground • Tar sand • Hot water extraction 	<ul style="list-style-type: none"> • Above ground • Oil shale • Paraho retorting

^a Vernal, Ut. is actually located in the Western Region. It was chosen to demonstrate a tar sand process and a sufficiently rich feedstock was not available in the Central Region.

It may initially appear that rural areas offer obvious attractions. Land area is abundant and available at reasonable prices and the social pressure to restrict development is overshadowed by the desire to develop economically to maintain or improve the local employment situation. Unfortunately, these advantages must be weighed against the major potential impacts on relatively undeveloped social and economic infrastructure and the potential impact of displaced agricultural labor. The more developed urban areas have existing infrastructures that can absorb the impacts resulting from new local industry, but environmental or political restrictions may inhibit growth.

TABLE 12-3
COMMON OUTLINE FOR DESCRIPTION OF SETTINGS

<p><u>DEMOGRAPHIC</u></p> <ul style="list-style-type: none"> • Population • Population Trends • Population Density <p><u>LAND</u></p> <ul style="list-style-type: none"> • Area • Land Use <p><u>ECONOMICS</u></p> <ul style="list-style-type: none"> • Economic Base • Labor Force <ul style="list-style-type: none"> - Employment by SIC - Unemployment - Trends • Per Capita Income • Financial Institutions 	<p><u>SOCIAL</u></p> <ul style="list-style-type: none"> • Government • Municipal Services <ul style="list-style-type: none"> - Police - Fire - Medical - Water supply - Solid waste disposal - Electric power generation • Education • Culture • Transportation • Housing <p><u>ENVIRONMENT</u></p> <ul style="list-style-type: none"> • Natural Beauty • Climate • Resources <ul style="list-style-type: none"> - Natural - Wildlife - Scarce • Water Quality • Air Quality • Noise
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CHAPTER 13

CASE STUDIES AND RESULTS

13.1 Selected Case Studies: Summary

This chapter presents the common data baselines and SELECS methodology results for each of the nine selected case studies mentioned in Chapter 12. For each case study there is a summary of the baseline data, a scenario of the area with its proposed technology, results and analysis of the socioeconomic and environmental impacts resulting from the incorporation of data for each site into the SELECS methodology, and site references.

Three of these sites, Rawlins, Pittsburgh, and Charleston are presented in detail in Volume 1, "Environmentally-Acceptable Fossil Energy Site Evaluation and Selection: Methodology and User's Guide." Further discussion of all nine sites is presented in "Methodology and User's Guide for Evaluating Socioeconomic and Environmental Impacts of Fossil Energy Conversion Facilities at Potential Sites," available from NTIS. As only the results of the methodology application are presented here, it is recommended that the reader refer to these reports for further explanation, and demonstration of the SELECS methodology.

13.2 Significance of the Results

The results are functions of both the site-specific data and the characteristics of the process or technology employed. Reversing the location at which two different processes are hypothesized will tend to change the relative magnitudes of the Scores. For example, if the Solvent Refined Coal process were examined for Jackson, Ohio and In Situ Coal Gasification at Charleston, West Virginia (opposite locations from those actually examined herein), the Site & Process Score for Jackson would be substantially larger than that for Charleston, primarily due to the larger manpower requirements of the Solvent Refined Coal process. Hence, the results must be considered site and process unique.

For all nine illustrative cases, the average variably and uniformly weighted Site & Process Scores are 0.270 and 0.258, respectively. The uniformly weighted Score for Kansas City (Case #4) is about 1/6 of the average, while the Score for Vernal (Case #6) is about twice as large as the average.

13.2.1 Regional Trends

The magnitude of the Site & Process Scores is similar in the Eastern and Central examples but is considerably larger for the Western examples. In the West, towns tend to be separated by larger distances. Thus, a single municipality is more likely to receive the major (e.g., 80% or more) portion of the incoming population and will, therefore, be more susceptible to adverse socioeconomic impacts. Water-related impacts (availability and quality) also tend to be more serious in the West, since there is generally less water than in the Eastern and Central parts of the nation. Other environmental impacts do not appear to vary significantly between different geographical areas.

13.2.2 Population Trends

As might well be expected, the Site & Process Score tends to be larger as the population of the community becomes smaller. Larger communities can accommodate a given influx of new residents with fewer and smaller socioeconomic problems.

One disadvantage which can often be expected for a larger community is that it may receive none of the property tax revenue collected from the plant. In rural areas, property taxes are frequently collected by the county, and every town within the county benefits from this revenue. However, in urban areas property taxes are more commonly collected by the individual municipalities. This may mean that only the municipality in which the conversion plant is located will receive tax revenue directly from the plant. In some cases, adjacent municipalities may need to increase their tax rates because of an increased infrastructure cost. This situation could be alleviated by a special arrangement for tax revenue distribution.

13.2.3 Category Scores

Table 13-1, and Figure 13-1 show the variably and uniformly weighted Category Scores for the nine case studies. The most important categories are ranked below by the average variably weighted score obtained:

- Infrastructure: (0.778), which will often be of major importance except in large cities.
- Land Use & Housing: (0.385), which tends to be more serious in the West and in rural areas.
- Community Services: (0.358), which also tends to be more serious in the West and in rural areas.
- Air Quality: (0.317), which does not directly depend on geographical or demographic characteristics.

Community Tax Revenue received a beneficial score (i.e., was negative) in five of the case studies and a score of zero in two others. A beneficial impact is more common in Western and rural areas.

13.2.4 Impact Elements

Table 13-2 shows the major elements for each case study. The following adverse impact elements received RIC Values of 0.40 or more in at least four of the case studies:

- Bonding capacity.
- Underdeveloped municipal land.
- Percent of marginal wastewater treatment capacity required.
- Percent of annual sulfur dioxide standard.
- Percent of 24-hour sulfur dioxide standard.
- Percent increase in dentists.
- Percent increase in firemen.

A reduction in unemployment will, of course, result from any development which creates new jobs. In seven of the nine cases, the reduction was the maximum (one-third) allowed by the algorithm. A decrease in the municipal tax rate was predicted in six of the case studies and was at least 40% in three. A beneficial change in electrical energy imports/exports was found in two of the nine examples.

TABLE 13-1
CATEGORY SCORES FOR THE NINE CASE STUDIES

CATEGORY	WEIGHTING	CASE 1 PITTSBURGH, PA	CASE 2 CHARLESTON, WV	CASE 3 JACKSON, OH	CASE 4 KANSAS CITY, MO	CASE 5 BLOOMINGTON, IL	CASE 6 VERNAL, UT	CASE 7 BISMARCK, ND	CASE 8 FARMINGTON, NM	CASE 9 RAWLINS, WY
1. EMPLOYMENT & POPULATION	VARIABLE Uniform	0 0	0.100 0.100	0.100 0.100	0 0	0.040 0.040	1.0 1.0	0.130 0.130	0.170 0.170	0.660 0.660
2. COMMUNITY SERVICES	VARIABLE Uniform	0.006 0.008	0.353 0.381	0.149 0.148	0 0	0.055 0.057	0.962 0.968	0.600 0.591	0.429 0.430	0.670 0.684
3. INFRASTRUCTURE	VARIABLE Uniform	0 0	1.0 1.0	1.0 1.0	0 0	1.0 1.0	1.0 1.0	1.0 1.0	1.0 1.0	1.0 1.0
4. LAND USE & HOUSING	VARIABLE Uniform	0 0	0.050 0.060	0.518 0.360	0 0	0.523 0.363	0.750 0.667	0.750 0.667	0.228 0.270	0.650 0.533
5. UTILITIES	VARIABLE Uniform	0.007 0.010	0.011 0.010	0.020 0.020	0 0	0.250 0.250	0.650 0.500	0.026 0.020	0.089 0.070	0.780 0.780
6. AIR QUALITY	VARIABLE Uniform	0.698 0.644	0.414 0.466	0.330 0.212	0.348 0.408	0.085 0.090	0.350 0.346	0.275 0.300	0.281 0.280	0.068 0.070
7. WATER QUALITY	VARIABLE Uniform	0 0	0 0	0 0	0 0	0.010 0.010	0 0	0 0	0 0	0 0
8. ENDANGERED WILDLIFE	VARIABLE Uniform	0 0	0.010 0.010	0 0	0 0	0 0	0.072 0.073	0.150 0.150	0.105 0.105	0.030 0.030
9. AESTHETICS & SITES	VARIABLE Uniform	0.010 0.010	0.005 0.005	0.090 0.090	0 0	0.020 0.020	0.365 0.365	0.365 0.365	0.110 0.110	0.210 0.210
10. COMMUNITY TAX REVENUE	VARIABLE Uniform	0 0	0.050 0.050	-1.0 -1.0	0 0	-0.340 -0.340	0.020 0.020	-1.0 -1.0	-0.400 -0.400	-1.0 -1.0
SITE & PROCESS SCORE	VARIABLE Uniform	0.114 0.067	0.221 0.209	0.261 0.214	0.063 0.045	0.218 0.203	0.503 0.495	0.359 0.380	0.272 0.271	0.419 0.440

Figure 13.1 Site & Process Scores for nine illustrative examples.
13-4

TABLE 13-2

IMPACT ELEMENT SCORES: MAJOR ADVERSE AND BENEFICIAL IMPACTS

Case No.	Impact Element	Impact Ratio (RIC VALUE)	Discussion
1 Pittsburgh, PA	6.9 Annual SO ₂ Concentration	99.5 (1.0)	The SO ₂ emissions would use the entire allowable ambient SO ₂ annual average concentration increase.
	6.10 NO _x Concentration Margin	54.6 (1.0)	The NO _x emissions would increase the annual average ambient NO _x concentration halfway from its present level to the primary ambient standard.
	6.11 24 hr. SO ₂ Concentration	60.3 (1.0)	The SO ₂ emissions would use up 60% of the allowable ambient SO ₂ 24 hr. average concentration increase.
2 Charleston, WV	1.7 Regional Unemployment	-33.3 (-1.0)	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in Kanawha County.
	2.13 Water Supply	112 (1.0)	The increase in demand for potable water would exceed the marginal capacity of the existing treatment plant.
	2.14 Wastewater Treatment	- (1.0)	No marginal capacity exists; therefore, the present treatment plant cannot accommodate any population increase.
	3.13 Bonding Capacity	229 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Charleston would have to issue bonds totaling more than twice the unused portion of the legal bonding limit.
	6.9 Annual SO ₂ Concentration	73.2 (1.0)	The SO ₂ emissions would use up almost 3/4 of the allowable ambient SO ₂ annual average concentration increase.
	6.12 24 hr. SO ₂ Concentration	140 (1.0)	The SO ₂ emissions would result in violation of the 24 hr. PSD Standard.
3 Jackson, OH	1.7 Regional Unemployment	-33.3 (-1.0)	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in Jackson County.
	3.13 Bonding Capacity	133 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Jackson would have to issue bonds in excess of the unused portion of the legal limit.
	4.10 Municipal Land	281 (1.0)	The demand for land within the municipality would be almost three times the amount which is underdeveloped.
	6.10 NO _x Concentration Margin	56.9 (1.0)	The NO _x emissions would increase the annual average ambient NO _x concentration more than halfway from its present level to the primary ambient standard.
	10.7 Municipal Tax Rate	-52.5 (1.0)	Revenues derived from new industries and residents would more than offset the increased municipal expenditures, and the municipal tax rate could be cut in half.

TABLE 13.2 (Continued)

Case No.	Impact Element		Impact Ratio (RIC VALUE)	Discussion
4 Kansas City, MO	6.9	Annual SO ₂ Concentration	38.2 (0.60)	The SO ₂ emissions would use up about 2/5 of the allowable ambient SO ₂ annual average concentration increase.
	6.11	24 hr. Part. Concentration	28.8 (0.37)	The increase in particulate emissions would use up about 1/4 of the allowable ambient particulate 24 hour average concentration increase.
	6.12	24 hr. SO ₂ Concentration	75.8 (1.0)	The increase in SO ₂ emissions would use up about 3/4 of the allowable ambient SO ₂ 24 hour average concentration increase.
5 Bloomington, IL	1.7	Regional Unemployment	-33.3 (-1.0)	The power plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in McLean County.
	3.13	Bonding Capacity	186 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Bloomington would have to issue bonds totaling almost twice the unused portion of the legal limit.
	4.10	Municipal Land	118 (1.0)	The demand for land within the municipality would exceed the amount which is underdeveloped.
	5.4	Electrical Energy	-84.4 (-0.90)	The additional electrical energy generated by the plant would almost double the amount exported by the state.
6 Vernal, UT	1.6	Community Population	209 (1.0)	The municipal population would triple, leaving the current residents with little political and social influence.
	1.7	Regional Unemployment	-33.3 -1.0	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in Uintah County.
	Category 2: Community Services		(0.968; uniformly weighted)	Major impacts are predicted for all ten elements in this category. Eight of the elements received maximum RIC Values.
	3.13	Bonding Capacity	3123 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Vernal would have to issue bonds totaling more than 30 times the unused portion of the legal limit.
	4.2	Municipal Housing	349 (1.0)	Nearly 4,500 new housing units would be needed, creating a secondary construction boom.
	4.10	Municipal Land	217 (1.0)	The demand for land within the municipality would be more than twice the amount which is underdeveloped.
	5.6	Surface Water	34.2 (1.0)	About 1/3 of the available surface water is assumed to be used by the plan (based on average flow conditions).

TABLE 13-2 (Continued)

Case No.	Impact Element		Impact Ratio (RIC Value)	Discussion
7 Bismarck, ND	1.7	Regional Unemployment	-33.3 (-1.0)	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in Burleigh County.
	2.6	Doctors	23.4 (1.0)	Increasing the number of doctors by this amount may pose problems, and a temporary shortage is likely to result.
	2.8	Hospital Beds	24.1 (1.0)	An increase of this magnitude would require the construction of a new hospital or the addition of wings to an existing hospital.
	2.10	Dentists	23.6 (1.0)	Increasing the number of dentists by this amount may pose problems, and a temporary shortage is likely to result.
	3.13	Bonding Capacity	216 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Bismarck would have to issue bonds totaling more than twice the unused portion of the legal limit.
	4.2	Municipal Housing	29.5 (1.0)	A secondary construction boom would be created by the large requirement for new housing units.
	4.10	Municipal Land	225 (1.0)	The demand for land within the municipality would be more than twice the amount which is under-developed.
	10.7	Municipal Tax Rate	-49.0 (-1.0)	Revenues derived from new industries and residents would more than offset the increased municipal expenditures, and the municipal tax rate could be cut in half.
8 Farmington, NM	1.7	Regional Unemployment	-33.3 (-1.0)	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in San Juan County.
	2.8	Hospital Beds	39.8 (0.99)	An increase of this magnitude would require the construction of a new hospital or the addition of wings to the existing hospital.
	2.10	Dentists	32.6 (0.51)	The large increase in demand for dental services may create a temporary shortage.
	2.14	Wastewater Treatment	97.5 (1.0)	The existing treatment plant would be unable to handle any growth beyond that associated with the conversion plant.
	3.13	Bonding Capacity	278 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Farmington would have to issue bonds totaling almost three times the unused portion of the legal limit.
	4.2	Municipal Housing	41.6 (0.71)	A secondary construction boom would be created by the large demand for new housing units.

TABLE 13-2 (Concluded)

Case No.	Impact Element	Impact Ratio (RIC Value)	Discussion
9 Rawlins, WY	1.7 Regional Unemployment	-33.3 (-1.0)	The conversion plant and secondary businesses would provide jobs for 1/3 of the unemployed labor force in Carbon County.
	2.2 Policemen	60.7 (1.0)	A temporary shortage would be likely before an adequate number of new police officers could be recruited and trained.
	2.4 Firemen	466 (1.0)	The present system, relying heavily on volunteer firemen, would probably have to be converted to a department run by the town.
	2.14 Wastewater Treatment	∞ (1.0)	Municipal wastewater treatment facilities may be needed for the more densely populated town.
	3.13 Bonding Capacity	933 (1.0)	In order to expand the municipal infrastructure to accommodate the new residents, Rawlins would have to issue bonds equal to several times the unused portion of the legal limit.
	4.10 Municipal Land	246 (1.0)	The demand for land within the municipality would be about 2-1/2 times the amount which is under-developed.
	10.7 Municipal Tax Rate	-69.3 (-1.0)	Revenues derived from new industries and residents would more than offset the increased municipal expenditures, and a 70% reduction in the municipal tax rate would be possible.

CASE #1: PITTSBURGH, PENNSYLVANIA

DEMOGRAPHICS

Pittsburgh had a 1970 population of 520,117 and a population density of 9,300 people/sq mi [3]. From 1970 to 1973, Pittsburgh's population declined 8 percent, while the overall SMSA (Standard Metropolitan Statistical Area), of Allegheny, Beaver, Washington and Westmoreland Counties declined 0.9 percent. The SMSA's total 1970 population was 2,401,245, making the density 823.3 people/sq mi [2,3,4,5]. Of Pittsburgh's population, 21 percent was nonwhite, 29 percent was under 18, and 14 percent was over 65 years old [14].

LAND

Pittsburgh occupies 55.5 sq mi (8%) of Allegheny County's 691 sq mi. The four-county SMSA totals 3,048 sq mi. Pittsburgh's residential sector is 47 percent of its total land area. Twenty-one percent of the city is comprised of industrial, commercial, public and semipublic land, 27 percent is underdeveloped forest and grazing, 4.8 percent is water and wetlands, and less than one percent of the land area is employed for mining extraction. The county devotes almost a quarter of its land to residential use [23].

ECONOMICS

The Pittsburgh area is responsible for one-fifth of the nation's steel-making capacity and is a major corporate headquarters [3]. Unemployment in the SMSA was 7.4 percent in 1975, which represents 73,000 of the 980,000 labor force. The largest employment sectors are manufacturing, wholesale/retail, services, and government [2,4,5,6,7,8,9]. Per capita income in Pittsburgh was \$4,426 in 1974, which was below the 1974 national average of \$5,487 [3,10]. Financial services are provided by ten state banks, 23 federal savings and loan associations, and 54 state savings and loan associations [1].

The total revenue for Pittsburgh in 1977 was \$136,132,430. Property tax accounted for 31 percent (100 percent assessed) of this revenue. The local mill rate is approximately 51.6 [27].

SOCIAL

Pittsburgh is governed by a Mayor and Council. Primary civil services are provided by 1,459 uniformed policemen (2.8 per 100 residents) and 1,067 firemen (2.0 per 1000 residents) which are higher than the national averages of 2.1 policemen and 1.5 firemen per 1000 residents, respectively. Medical services are supported by 22 area hospitals [3].

Water is supplied by the Ohio River, which has a mean annual flow of 21,286 MGD. Natural and man-made lakes represent a secondary water source [12].

Pennsylvania had an electric generating capacity of 27.2 GW in 1974. In 1974, $99,884 \times 10^6$ kwh were generated and $89,621 \times 10^6$ kwh were sold within the state, making Pennsylvania a net exporter of electricity [16].

In 1977, Pittsburgh had a municipal elementary and high school enrollment of approximately 61,689 students. These students represented about 12 percent of the municipal population, based on CEM's 1977 population estimates [29].

Culturally, the Pittsburgh municipal area supports an opera company, a ballet, a youth symphony and symphony orchestra. Recreation is provided by three zoos, a planetarium, an aquarium and museum, as well as four amusement parks, harness racing, and major league sports. This major eastern urban area boasts a sophisticated information media, composed of six daily newspapers, five TV stations, and 22 radio stations [2,3].

Nine major highways serve the Pittsburgh area. Mass transit systems are not well established, but are now being expanded. Nineteen railroads, two bus lines, five trolley lines and seven airlines also serve the region, providing easy access to the metropolitan area [3].

There were 188,840 housing units in the Pittsburgh metropolis, with an average of 2.7 people per unit in 1970. The SMSA had 789,771 housing units with 2.7 people per unit. There were approximately 985 units for sale and 7,380 units available for rent in 1970 within the municipality [17].

ENVIRONMENT

Pittsburgh is located in the Appalachian Mountains at the confluence of three major waterways, the Allegheny River, Monongahela River and the Ohio River. Area climate exhibits wide seasonal variations, with a mean annual temperature of 50°F. There are an average of 5,930 heating degree days annually. The average snowfall is 31 inches and the mean wind velocity is 9 mph, primarily from the southwest. Coal, oil, gas, iron, salt and gypsum are included among the area's many natural resources. Wildlife inhabitants of this oak-hickory forest region include white-tail deer, raccoons, foxes and rodents [10,24]. There are no nationally endangered animals known to be living within a 50 mi radius of the city [26].

One major 200 MGD sanitary treatment plant serves Pittsburgh and the surrounding area, emitting treated effluent to the Ohio River. The Monongahela River is one of the most polluted rivers in the country. Major pollutants include phenols, cyanides, and iron [21,35].

Air quality is considered poor around Pittsburgh. Suspended particulates have a maximum value of 402 $\mu\text{g}/\text{m}^3$, which is much greater than the National Standard of 260 $\mu\text{g}/\text{m}^3$, for a 24-hour period. SO_2 is a problem with 454 $\mu\text{g}/\text{m}^3$ for a high value, which is greater than the National Standard of 365 $\mu\text{g}/\text{m}^3$. Also, periodic ozone violations occur [18].

CASE #1 SCENARIO: Pittsburgh, Pennsylvania/Low Btu Coal Gasification

In this illustrative example, a hypothetical low Btu Bituminous coal gasification plant is proposed for a location 5 miles northeast of Pittsburgh. A one mile spur would connect the plant to the Penn Central railroad to the north, and a water pipeline would extend 0.5 miles north to the Allegheny River. Highway access is readily available, since existing roads lead to Interstate 76. The low Btu gas produced would be piped to an existing power plant, one mile to the WNW.

The population of Pittsburgh was 520,117 in 1970. The metropolitan area is heavily industrialized (including several industries which are energy based), and coal mining is a major component of the economy of the outlying areas.

The COGAS process, which can produce varying amounts of gas and oil, is assumed for this facility. The outputs are taken as 700 million standard cubic feet per day (scfd) of 340 Btu/scf gas and 4000 barrels of oil per day. In order to minimize transportation costs, the gas must be consumed locally. Feedstock requirements for the plant include 12,000 tons of coal and 9.8 million gallons of water per day. Construction would begin 3 years after the final decision to build and would take 4 years to complete. During the estimated 25 years operating life of the plant, 181 persons would be employed on site and 705 would be employed at surface mines a few miles away.

TABLE OF RESULTS

Case #1: PITTSBURGH, PA/Low Btu Coal Gasification

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	0.25	0	1.0	0	6.12	Percent 24-Hr SO ₂ Standard	60.3	1.00	0.17	0.170
1.7	Change in Unemployment	-1.97	-0.03	1.0	-0.03	CATEGORY 6 TOTAL			3.22	1.0	0.698
CATEGORY 1 TOTAL			0	1.0	0	7.1	% Assimilation Capacity Remaining	99.9	0	1.0	0
2.2	Percent Increase in Policemen	0.25	0	0.10	0	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	0.25	0	0.09	0	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	0.25	0	0.12	0	8.1	% Habitat Area Disturbed	--	--	--	--
2.8	Percent Increase in Hospital Beds	0.25	0	0.10	0			--	--	--	--
2.10	Percent Increase in Dentists	0.25	0	0.12	0			--	--	--	--
2.12	Percent Increase in Teachers	0.30	0	0.08	0			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	2.60	0.01	0.10	0.001			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	1.20	0.01	0.10	0.001	CATEGORY 8 TOTAL			0	1.0	0
2.15	% Marginal Solid Waste Area Used	0.20	0	0.12	0	9.1	% Reduction in Panoramic View	1.08	0.02	0.50	0.010
2.16	% Increase in Park & Recreation Area	2.00	0.06	0.07	0.004	9.2	Historical & Archeological Sites	A	0	0.50	0
CATEGORY 2 TOTAL			0.08	1.0	0.006	CATEGORY 9 TOTAL			0.02	1.0	0.010
3.13	Percent Bonding Capacity Required	2.6	0	1.0	0	10.7	Percent Change in Tax Rate	0.17	0	1.0	0
CATEGORY 3 TOTAL			0	1.0	0	CATEGORY 10 TOTAL			0	1.0	0
4.2	Percent Increase in Mun. Housing	0	0	0.25	0	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	0.40	0	0.50	0						
4.11	% Underdeveloped Regional Land	0.01	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			0	1.0	0	1	Employment/Population	0.11	0	0	
5.4	% Change in Elec. Import/Export	3.50	0.02	0.35	0.007	2	Community Services	0.09	0.001	0.001	
5.6	% Available Surface Water Required	0.48	0	0.65	0	3	Infrastructure	0.10	0	0	
CATEGORY 5 TOTAL			0.02	1.0	0.007	4	Land Use/Housing	0.10	0	0	
5.8	% Annual Particulate Standard	9.4	0.08	0.17	0.014	5	Utilities	0.07	0.001	0	
5.9	% Annual SO ₂ Standard	99.5	1.00	0.17	0.170	6	Air Quality	0.16	0.064	0.112	
6.10	% NO _x Concentration Margin	54.6	1.00	0.32	0.320	7	Water Quality	0.14	0	0	
6.11	% 24-Hr Particulate Standard	13.3	0.14	0.17	0.024	8	Endangered Wildlife	0.07	0	0	
						9	Aesthetics and Sites	0.06	0.001	0.001	
						10	Community Tax Revenue	0.10	0	0	
						SUM OF ADVERSE IMPACTS			1.00	0.067	0.114

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS CASE #1: Pittsburgh, PA/Low Btu Coal Gasification

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.067 and 0.114, respectively, indicating a small overall impact.
- The largest contributing category is Air Quality with a score of 0.698 (prior to the application of category weights).
- Socioeconomic and beneficial impacts are small because the labor force required is a small fraction of the population.
- The Site & Process Scores are the second lowest obtained for the nine illustrative examples.

MAJOR ADVERSE IMPACTS

- Air Quality: Sulfur dioxide and nitrogen oxides concentrations would rise by a considerable amount.
- All other impact elements have small RIC Values.

BENEFICIAL IMPACTS

- Employment and Population: A 2% decline in unemployment in the SMSA is the only beneficial impact predicted.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score is 70% larger than the uniformly weighted score due to the small number of categories whose scores are affected by the weights.

AMELIORATING ACTIONS

- More efficient control of air effluents would reduce the only significant impact.

IMPACTS REQUIRING MORE ANALYSIS

- Air quality modeling.

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CASE #2: CHARLESTON, WEST VIRGINIA

DEMOGRAPHICS

Charleston, the capitol of West Virginia, is located in Kanawha County (Charleston SMSA). In 1975, Charleston's population was estimated to be 67,348, which represents a 22 percent decline over the previous 15 years [4]. A more moderate population decline of 7 percent was experienced during this 15-year period in Kanawha County [4]. Municipal population density was approximately 2,299 residents/sq mi and fell to 203/sq mi for the overall SMSA [4]. Fifty-eight percent of the city's population was in the working age group of 18-65, and 11 percent of the total population was nonwhite [1].

LAND

Charleston occupies 29.3 sq mi (2.3%) of the Charleston SMSA's 1,264 sq mi. Underdeveloped forest and grazing land takes up 77 percent of the SMSA's land area, with only 2 percent of the land residential. Industrial, commercial, public and semi-public use accounts for 14 percent, 1 percent is devoted to parks and recreation and 6 percent of the land is used for mining and extraction or is derelict [4, 14].

ECONOMICS

Charleston's economy is multifaceted, with coal and chemical industries being the most identifiable [4]. Because the city is the state capitol, government work also contributes significantly to Charleston's economic base. The largest numbers of persons are employed in wholesale/retail, manufacturing, government and services [4]. The SMSA labor force was approximately 111,400, of which 3.1 percent (3,400) were unemployed in 1977 [4].

In 1975, the SMSA per capita income was \$6,267, which represents a 60 percent increase over the 1970-1975 period [1]. This was slightly higher than the national average of \$5,834. Financial services in the Charleston area are provided by ten nationally chartered and thirteen state chartered banks [4].

The total revenue for Charleston in 1976-1977 was \$23,300,857. Property taxes accounted for 14.3 percent (52% assessed) of this revenue. The local mill rate is approximately 37.5 (Res.) and 75 (Commercial and Industrial) [17].

SOCIAL

Charleston has a Mayor/Council form of government [1]. Primary civil services are provided by 173 uniformed policemen (2.6 per 1000 residents) and 168 uniformed firemen (2.5 per 1000 residents) [1]. These figures are greater than the national averages of 2.1 and 1.6 police and firemen per 1000 residents, respectively [1].

Medical services are supported by five area hospitals, 144 doctors (2.1 per 1000 residents), which is greater than the nation's average of 1.7 per 1000 residents, and 104 dentists (1.5 per 1000 residents) [2,6].

Charleston's water supply is drawn from the Kanawha River. A major filtration plant processing a current load of 30 MGD has a 40 MGD capacity and is expandable to 80 MGD. An activated sludge secondary treatment plant serves 100,000 residents, emitting its effluent to the Kanawha River [4].

Power generated within West Virginia in 1974 was $61,505 \times 10^6$ kwh, based on a capacity of 12.4 GW. The total amount sold within the state was only $17,216 \times 10^6$ kwh which means that the area was a net exporter of electricity [13].

In 1977, Charleston's municipal elementary and high school had an enrollment of approximately 10,096 students. These students represented 15 percent of the 1975 municipal population [4,20].

Culturally, the Charleston municipal area supports a civic center, a culture and arts center, symphony orchestra, a light opera guild, and a state museum [5]. Forty playgrounds, six golf courses, and numerous parks provide recreational opportunities [4,5,6]. Fishing, swimming, and boating are also popular pastimes.

Three newspapers, 13 radio stations, and four TV stations operate in Charleston; cable TV is also available [6].

Four airlines serve the city, as well as both passenger and freight rail companies, barge and bus lines. Three interstate highways run through the city [4].

In 1970, there were 27,153 housing units in Charleston. The median number of rooms per unit was 5.0 and the average number of occupants per unit was 2.3. There were approximately 242 units available for sale and 823 for rent [7].

ENVIRONMENT

Charleston is located at the confluence of the Elk and Kanawha Rivers in the scenic western foothills of the Appalachians. The city is surrounded by coal, chemical, steel, glass, and timber towns [5].

Area resources include coal, oil, natural gas, salt, timber, clays, silica, and an abundance of water [6]. The southern bald eagle, an endangered bird on the federal list, has been sighted in Kanawha County [16].

Local climate is marked by sharp seasonal and day-to-day temperature contrasts. Average daily maximum temperature is 66°F and average daily minimum temperature is 44.4°F . Precipitation is measurable approximately 149 days/year and averages 40.75 inches annually. There are approximately 4,590 heating degree days and 1,055 cooling degree days annually. The mean wind velocity is 6.5 mph, primarily from the southwest [4].

Charleston has a major asset in its abundant water supply. Even with substantial industrial discharges, water quality has been improving. Chemical and physical data indicate several pollution problems in the Kanawha River Basin. One is the high total and fecal coliform levels. A second is organic wastes from chemical industries on the river's mainstem. A third problem is brine and oil from the oil and gas industry. A black water problem, due to inadequately maintained facilities relating to coal handling and cleaning, exists in some of the tributaries. Principal waste sources (chemical industries and municipal discharges) are concentrated along a 30-mile section of the Kanawha River encompassing Charleston [25].

Charleston has fair air quality; the highest 24-hr measurement of suspended particulates is $418 \mu\text{g}/\text{m}^3$, SO_2 is $270 \mu\text{g}/\text{m}^3$, NO_x is $225 \mu\text{g}/\text{m}^3$ and an 8-hr measurement of CO is $8.1 \mu\text{g}/\text{m}^3$. These values compare to National Standard Values of $260 \mu\text{g}/\text{m}^3$, $265 \mu\text{g}/\text{m}^3$, $100 \mu\text{g}/\text{m}^3$ and $10 \mu\text{g}/\text{m}^3$, respectively [4,10].

CASE #2 SCENARIO: Charleston, West Virginia/Bituminous Coal Liquefaction

A bituminous coal liquefaction plant would be constructed about 12.5 miles northwest of Charleston, near the southeast corner of Putnam County. U.S. Route 25, the Penn Central Railroad and a high voltage power line which border the Kanawha River pass within 1 mile of the proposed site. A new road, railroad spur and transmission line will provide access and electricity to the site, and water will be piped from the river along a similar route. The combined right-of-way over the 1 mile route leading southwest from the plant will be 550 feet. The plant site is located adjacent to existing underground coal mines, which is ideal for conveyor belt transportation of the coal to the conversion plant.

Charleston had a population of 67,348 in 1975, and the city's economy relies heavily on coal production.

The Solvent Refined Coal process will be utilized to refine the coal into 7,810 tons per day of clean, solid boiler fuel, having a heating value equivalent to 41,700 barrels of oil per day. Feedstock requirements include 12,100 tons of bituminous coal and 10.8 million gallons of water per day. Construction is scheduled to commence in 3 years and will take 5 years to complete. During the 30 year plant life, 495 plant workers and 1,560 miners will be employed.

TABLE OF RESULTS

Case #2: CHARLESON, WV/Bituminous Coal Liquefaction

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	20.8	0.10	1.0	0.100	6.12	Percent 24-Hr SO ₂ Standard	140	1.00	0.17	0.170
1.7	Change in Unemployment	33.3	1.00	1.0	1.000	CATEGORY 6 TOTAL			2.33	1.0	0.414
CATEGORY 1 TOTAL			0.10	1.0	0.100	7.1	% Assimilation Capacity Remaining	99.9	0	1.0	0
2.2	Percent Increase in Policemen	20.1	0.26	0.10	0.026	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	19.7	0.24	0.09	0.022	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	19.9	0.08	0.12	0.001	8.1	% Habitat Area Disturbed	0.40	0.01	1.0	0.010
2.8	Percent Increase in Hospital Beds	19.3	0.17	0.10	0.017			--	--	--	--
2.10	Percent Increase in Dentists	19.8	0.19	0.12	0.023			--	--	--	--
2.12	Percent Increase in Teachers	25.6	0.29	0.08	0.023			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	112	1.00	0.10	0.100			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	∞	1.00	0.10	0.100	CATEGORY 8 TOTAL			0.01	1.0	0.010
2.15	% Marginal Solid Waste Area Used	3.2	0.01	0.12	0.001	9.1	% Reduction in Panoramic View	0.52	0.01	0.50	0.005
2.16	% Increase in Park & Recreation Area	44.9	0.57	0.07	0.040	9.2	Historical & Archeological Sites	A	0	0.50	0
CATEGORY 2 TOTAL			3.81	1.0	0.353	CATEGORY 9 TOTAL			0.01	1.0	0.005
3.13	Percent Bonding Capacity Required	229	1.00	1.0	1.000	10.7	Percent Change in Tax Rate	16.2	0.05	1.0	0.05
CATEGORY 3 TOTAL			1.00	1.0	1.000	CATEGORY 10 TOTAL			0.05	1.0	0.05
4.2	Percent Increase in Mun. Housing	17.2	0.16	0.25	0.040	SITE AND PROCESS IMPACT SUMMARY					
4.10	% Underdeveloped Municipal Land	5.1	0.02	0.5000	0.010	() = Beneficial Impact					
4.11	% Underdeveloped Regional Land	0.2	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			0.18	1.0	0.050	1	Employment/Population	0.11	0.010	0.011	
5.4	% Change in Elec. Import/Export	0.9	0.01	0.35	0.004	2	Community Services	0.09	0.038	0.032	
5.6	% Available Surface Water Required	1.45	0.01	0.65	0.007	3	Infrastructure	0.10	0.100	0.100	
CATEGORY 5 TOTAL			0.02	1.0	0.011	4	Land Use/Housing	0.10	0.006	0.005	
6.8	% Annual Particulate Standard	3.6	0.04	0.17	0.007	5	Utilities	0.07	0.001	0.001	
6.9	% Annual SO ₂ Standard	73.2	1.00	0.17	0.170	6	Air Quality	0.16	0.047	0.066	
6.10	% NO _x Concentration Margin	11.5	0.12	0.32	0.038	7	Water Quality	0.14	0	0	
6.11	% 24-Hr Particulate Standard	16.2	0.17	0.17	0.029	8	Endangered Wildlife	0.07	0.001	0.001	
						9	Aesthetics and Sites	0.06	0.001	0	
						10	Community Tax Revenue	0.10	0.005	0.005	
						SUM OF ADVERSE IMPACTS			1.00	0.209	0.221

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS

CASE #2: Charleston, WV/Bituminous Coal Liquefaction

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.221 and 0.209, respectively, indicating a moderate overall impact.
- The largest contributing category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- The maximum R/C value is obtained for the only beneficial impact element: unemployment.
- The Site & Process Scores are about 20% lower than the averages for the nine case studies.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity requirement is more than twice the available portion of the legal limit.
- Air Quality: Sulfur dioxide pollution may violate applicable standards.
- Community Services: The existing water supply and wastewater treatment facilities cannot accomodate the projected increase in demand, while park & recreational facilities would require substantial expansion.

BENEFICIAL IMPACTS

- Employment and Population: Unemployment in the Charleston SMSA would be reduced by one-third.
- No other beneficial impacts are predicted.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score is within 6% of the uniformly weighted score.

AMELIORATING ACTIONS

- Industrial and/or governmental funding to expand the municipal infrastructure is needed.
- More efficient control of sulfur dioxide in the stack gases would abate the air quality problem.
- Expansion or construction of new water facilities prior to the completion of the synthetic fuels plant would alleviate shortage.

IMPACTS REQUIRING MORE ANALYSIS

- Air quality modeling.
- Community service requirements.
- Tax revenues generated.

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19. *Charleston*, Topographic Map from the United States Department of the Interior Geological Survey, 1975. (NJ 17-5) (Used to obtain CEM estimate.)
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21. Year-round vacant units only. (See Reference 7.)
22. Persons per occupied unit, not necessarily year-round. (See Reference 7.)
23. CEM estimate using rental and homeowner vacancy rates for year-round units. (See Reference 7.)
24. CEM estimate, obtained by using public school student:teacher ratio. (See Reference 20.)
25. Letter Communication with Sara Casto, Kanawha River Basin, West Virginia Department of Natural Resources, Water Resources Division, West Virginia, March 30, 1978.
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28. Telephone communication with Joe Gero, Assistant Manning Director, City Planning Office, Charleston, West Virginia, June 6, 1978.

CASE #3: JACKSON, OHIO

DEMOGRAPHICS

Jackson, located in Jackson County in southeast Ohio, has a population of 7,284 (1977) and a population density of 2,117/sq mi. Jackson County had an estimated population of 28,474 (1977) and a density of 69.9 people/sq mi [3]. Jackson County population consists of 0.8 percent nonwhite residents, with 35 percent under 18 years old and 13 percent over 65 years old [1].

LAND

About one-half of the 417 sq mi of land area of Jackson County is forest and forest pasture, and 40 percent is open crop and pasture. The rest is urban, residential and used for other commercial purposes [2].

ECONOMICS

The 1977 civilian labor force in Jackson County was 11,000. Unemployment was 9.5 percent, or 1,050 [6]. Manufacturing and wholesale/retail sectors employed the largest percentage of workers. Agriculture and government employment are of minor importance to the regional economy [2]. The 1972 per capita income was \$2,543, which was below the national average of \$4,537 for the same year [14].

The total revenue for Jackson in 1976-1977 was \$2,486,548. Property tax accounted for 2.6 percent (35% assessed) of this revenue. The local mill rate is approximately 34.8 [18].

SOCIAL

Jackson is governed by a Mayor/Council form of government and the county by a County Council Board [7]. Primary civil services are provided by 11 policemen (1.5 per 1000 residents) and seven regular firemen (1.0 per 1000 residents). These figures are low compared with national averages of 2.1 policemen and 1.6 firemen per 1000 residents [1,2,7].

Medical services are provided by six physicians (0.8 per 1000 residents) which is lower than the 1.7 physicians per 1000 residents of the national average. Major medical facilities are not available in Jackson. The Oak Hill Clinic is 12 miles from Jackson and the facility serves Jackson residents [2,12].

The municipal water supply is a city-owned lake two miles from Jackson. Treatment capacity is 4 MGD and the daily average use is 1.2 MGD, serving 50 percent of Jackson County residents [3,5].

Electric power is supplied to Jackson from a system with 890,000 kw capacity. The Ohio State generating capacity was 23.4 GW in 1974, but only $98,191 \times 10^6$ kwh was generated and $105,703 \times 10^6$ kwh sold. Therefore, Ohio is a net importer of electric power [10,11].

In 1977, Jackson had a municipal elementary and high school enrollment of approximately 1,782 students. These students represented 24 percent of the 1977 municipal population [19,25].

Jackson is not of sufficient size to support organized cultural endeavors. Recreation is provided by a movie theater, municipal tennis courts, a swimming pool, a 9-hole golf course, and a country club [2,3].

Media service is provided by one local radio station licensed for day operation only. There are no television stations, but transmissions are received from Columbus, Ohio, and Huntington, West Virginia [2,3,5].

Jackson is served by six highways, two bus routes, and one taxi route. A County Airport is located three miles to the south and the only rail service is a passenger line located 15 miles to the north [2,3].

There are 2,517 housing units in Jackson. The median number of rooms per unit is 5.2 and the average number of occupants per unit is 2.4 [8,21].

ENVIRONMENT

Jackson County has gently sloping hills with an oak-hickory forest region and two lakes. The Jackson metropolis is located in the Appalachian foothills. Local climate is subject to seasonal variation with average daily maximum temperatures of 66.1°F and average daily minimum of 42.3°F. Normal annual precipitation is 41.17 inches. The average wind speed is 10 mph [3,5].

The Jackson area has an abundant supply of natural resources, including metal ores, coal, oil, clay, sand and gravel, silicon, shale, and limestone [3,5]. The bald eagle and the Indiana bat, both found in Ohio, are on the federal list of endangered species [15].

Stream water in Jackson tends to be highly acidic and has a high sulfur content. Drinking water is obtained mainly from Hammertown Lake, about six miles outside Jackson [23].

The air quality for Jackson is good. The maximum value of suspended particles in a 24-hour period is 102 $\mu\text{g}/\text{m}^3$, which is below the Primary National Standard of 260 $\mu\text{g}/\text{m}^3$ and below the Secondary Standard of 150 $\mu\text{g}/\text{m}^3$. SO_2 , CO, NO_2 and oxidants appear only in moderate to low concentrations [9,13].

CASE #3 SCENARIO: Jackson, Ohio/In Situ Coal Gasification

Jackson would have an *in situ* coal gasification facility above a large coal seam, six miles east of the town, just off Route 327. The gas would be upgraded in an above-ground plant to pipeline quality substitute natural gas (about 950 Btu/scf). Electric power lines cross the proposed site, but water requirements would probably be met by pumping from the Ohio River, through a 22 mile pipeline.

The population of Jackson was 7,284 in 1977 and has been rising at less than 1 percent per year. Coal and natural gas production is evident throughout the county and is a major contributor to the regional economy. Presumably, one or more of the existing natural gas pipeline right-of-ways could be used to transport the product to a distribution network.

Since the coal is gasified *in situ*, there would be no need for mining or ash disposal. Gasification of about 70 percent of the 16,900 tons/day of coal required can be expected. About 18 million gallons of water/day would also be consumed. The facility would have a design capacity of 250 million standard cu ft/day, and only minor amounts of sulfur and other byproducts would be produced. Construction would begin three years after a final decision to build. Because of the minimal surface equipment and preparation involved, it would be completed in another three years. About 500 people would be employed during the 20 year operating life.

TABLE OF RESULTS
Case #3: JACKSON, OH/In Situ Coal Gasification

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	20.4	0.10	1.0	0.100	6.12	Percent 24-Hr SO ₂ Standard	0.5	0.01	0.17	0.002
1.7	Change in Unemployment	-33.3	-1.00	0.50	-0.50	CATEGORY 6 TOTAL			1.06	1.0	0.330
CATEGORY 1 TOTAL			0.10	1.0	0.100	7.1	% Assimilation Capacity Remaining	99.9	0	1.0	0
2.2	Percent Increase in Policemen	21.5	0.29	0.10	0.029	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	22.3	0.30	0.09	0.027	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	22.4	0.24	0.12	0.029	8.1	% Habitat Area Disturbed	0	--	--	--
2.8	Percent Increase in Hospital Beds	21.0	0.11	0.10	0.011	8.1	% Habitat Area Distributed	0	--	--	--
2.10	Percent Increase in Dentists	20.0	0.18	0.12	0.022			--	--	--	--
2.12	Percent Increase in Teachers	23.8	0.24	0.08	0.019			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	7.8	0.03	0.10	0.003			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	8.3	0.04	0.10	0.004	CATEGORY 8 TOTAL			0	1.0	0
2.15	% Marginal Solid Waste Area Used	7.1	0.03	0.12	0.004	9.1	% Reduction in Panoramic View	8.2	0.18	0.50	0.090
2.16	% Increase in Park & Recreation Area	15.9	0.02	0.07	0.001	9.2	Historical & Archeological Sites	A	0	0.50	0
CATEGORY 2 TOTAL			1.48	1.0	0.149	CATEGORY 9 TOTAL			0.18	1.0	0.090
3.13	Percent Bonding Capacity Required	133	1.00	1.0	1.000	10.7	Percent Change in Tax Rate	-52.5	-1.00	0.50	-0.500
CATEGORY 3 TOTAL			1.00	1.0	1.000	CATEGORY 10 TOTAL			-1.00	0.50	-0.500
4.2	Percent Increase in Mun. Housing	18.1	0.07	0.25	0.018	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	281	1.00	0.50	0.500						
4.11	% Underdeveloped Regional Land	1.7	0.01	0.25	0.003	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			1.08	1.0	0.518	1	Employment/Population	0.12	0.011	0.012	
5.4	% Change in Elec. Import/Export	2.4	0.02	0.35	0.007	2	Community Services	0.10	0.016	0.015	
5.6	% Available Surface Water Required	5.4	0.02	0.65	0.013	3	Infrastructure	0.11	0.111	0.110	
CATEGORY 5 TOTAL			0.04	1.0	0.020	4	Land Use/Housing	0.11	0.040	0.057	
6.8	% Annual Particulate Standard	1.7	0.02	0.17	0.003	5	Utilities	0.08	0.002	0.002	
6.9	% Annual SO ₂ Standard	1.6	0.02	0.17	0.003	6	Air Quality	0.18	0.024	0.059	
6.10	% NO _x Concentration Margin	56.9	1.00	0.32	0.320	7	Water Quality	0.15	0	0	
6.11	% 24-Hr Particulate Standard	1.2	0.01	0.17	0.002	8	Endangered Wildlife	0.08	0	0	
						9	Aesthetics and Sites	0.07	0.010	0.006	
						10	Community Tax Revenue	(0.50)	(-0.500)	(0.500)	
						SUM OF ADVERSE IMPACTS			1.00	0.214	0.261

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS

CASE #3: Jackson, OH/In Situ Coal Gasification

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.261 and 0.214 respectively, and indicate a moderate overall impact.
- The largest contributing category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- Maximum RIC Values are obtained for the two beneficial impact areas: unemployment and tax rate reductions.
- The Site & Process Scores are near the average of the nine case studies.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity required exceeds the available portion of the legal limit.
- Land Use & Housing: The amount of municipal land needed is almost triple the underdeveloped land available.
- Air Quality: Nitrogen oxides emissions would consume about half the allowable increase in concentration.

BENEFICIAL IMPACTS

- Employment and Population: The county unemployment rate would be cut by one-third.
- Community Tax Revenue: The overall tax rate would be halved.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score exceeds the uniformly weighted score by 22%.

AMELIORATING ACTIONS

- A larger fraction of the process-related industries might be located outside the municipal boundaries.
- Industrial and/or governmental funding to expand the municipal infrastructure is needed.
- More efficient control of NO_x emissions would diminish the air quality impact.

IMPACTS REQUIRING MORE ANALYSIS

- Air quality modeling.
- Cost of the expanded infrastructure.
- Tax revenue generated.

References for Case #3 (continued)

18. Telephone Communication with Marta Drake, Jackson, Ohio, Jackson Town Auditor, Jackson Town Hall, May 11, 1978.
19. Apparently many of the schools within the town are regional. It was estimated that half of the students enrolled are actually from the town.
(See Reference 2.)
20. Year-round vacant units only. (See Reference 8.)
21. Persons per occupied unit not necessarily year-round. (See Reference 8.)
22. CEM estimate, using rental and homeowner vacancy rates for year-round units.
(See Reference 8.)
23. Telephone Communications with Mr. Pennington and Mr. Colson, South East District of the Ohio Environmental Protection Agency, Logan, Ohio, March 29, 1978.
24. Lerner, William. *Statistical Abstract of the United States 1976*, Washington, D.C., U.S. Department of Commerce, Bureau of the Census, 97th Edition, July 1976.
25. CEM estimate.
26. Telephone communication with Roger Jenkins, Service Director, Town Clerk's Office, Jackson, Ohio, June 6, 1978.

References for Case #3, Jackson, Ohio

1. *Jackson County Population Figures*, Battelle Institute, Jackson, Ohio, 1977.
2. *Jackson, Jackson, Ohio General Information and Data from Jackson Chamber of Commerce*.
3. *Comprehensive Development Plan for Jackson, Ohio*, Ohio University, 1978.
4. *Ohio Labor Market Information*, Jackson County, Ohio, Bureau of Employment Services, October 1977.
5. Gerlach, Arch C. *The National Atlas of the United States of America*, Washington, D. C., United States Department of the Interior Geological Survey, 1970.
6. *1970 Census of Population, Characteristics of the Population*, Washington, D.C., U. S. Department of Commerce, Social and Economic Statistics Administration, Bureau of Census, v. 1: Part 37.
7. *County Business Patterns 1970, Ohio*, Washington, D. C., U. S. Department of Commerce, Bureau of Census.
8. *Housing Characteristics for States, Cities and Counties*, Washington, D.C., U.S. Department of Commerce, 1973: Part 50.
9. *Monitoring and Air Quality Trends Report*, 1974, Research Triangle Park, North Carolina, U. S. Environmental Protection Agency, February 1976. (EPA-450/1-76-001)
10. "Census Estimate Predicts 13 States May Gain or Lose House Strength," *Arkansas Gazette*, Little Rock, Arkansas, January 23, 1978.
11. Bailey, David J. *Statistical Year Book of the Electrical Utility Industry*, New York, Edison Electric Institute, No. 42, 1975.
12. American Hospital Association. *American Hospital Association Guide to the Health Care Field*, Chicago, Illinois, 1977.
13. Telephone Communication with Jim Ligett, Southwest District, Ohio Environmental Protection Agency, Air and Water Department, March 28, 1978.
14. Grouby, Barbara H. (Ed.). *The County Year Book 1977*, Washington, D.C., National Association of Counties and International City Management Association, 1977.
15. *Endangered Wild Animals in Ohio*, Columbus, Ohio, Ohio Department of Natural Resources, Division of Wildlife, Publication 316, May 1, 1976 (R1276)
(The information obtained pertained to the State of Ohio.)
16. *Encyclopaedia Britannica, Micropaedia*, Chicago, Illinois, v. 1, 1974.
17. *Columbus, Topographic Map* from the United States Department of the Interior Geological Survey, 1967. (NJ 17-1) (Used to obtain CEM estimate.)

CASE #4: KANSAS CITY, MISSOURI

DEMOGRAPHICS

The growing municipal area of Kansas City, Missouri had a 1973 population of 488,000 [2,3]. The SMSA, which includes Cass, Clay, Jackson, Platte and Roy, Missouri and Johnson and Wyandotte, Kansas had a population of 1,273,900 (1970) and has experienced steady growth [1]. Population density within the SMSA ranged from about 1,600 people/sq mi in the Kansas City municipal region to less than 380 people/sq mi in the most rural areas [1,5]. In 1970, 23 percent of the population was nonwhite, 33 percent was under 18, and 12 percent was over 65 years old [3].

LAND

The SMSA occupies 381.3 sq mi including Kansas City, Kansas; Kansas City, Missouri and the seven surrounding counties [1]. About 70 percent of the land is vacant or used for agricultural purposes. Residential areas take up 13 percent; industry and commercial 2 percent; rivers and lakes 1 percent; parks, recreational and public/semi-public lands comprise 7 percent of the land area [5].

ECONOMICS

In August, 1976, the SMSA labor force was 607,253 (48% of the population). There were 36,950, or 6.1 percent unemployed [1]. Primary employment sectors are manufacturing, wholesale/retail and services. Mining activities are a minor employment area. The per capita income for the area, in 1975, was about \$5,400, which was slightly below the 1975 national average of \$5,834 [1,15]. Financial institutions include 18 banks and 6 savings and loan agencies in Kansas City, Kansas [2].

The total revenue for Kansas City, Missouri in 1976-1977 was \$230,907,314. Property tax accounted for 10.8 percent (33.3% assessed) of this revenue. The local mill rate is approximately 75.0 [20,21].

SOCIAL

The local government for Kansas City consists of a Mayor, Aldermen/Councilmen, and an Administrator/Manager [3]. Municipal services for Kansas City are provided by 1,573 uniformed police (2.3 per 1000 residents) and by 1,210 firemen (1.8 per 1000 residents). These figures are approximately equal to the national averages. Medical services are supported by hospitals with 8,110 beds, 38 clinics and 92 nursing homes. There are 21,145 doctors (1.6 per 1000 residents), which is approximately equal to the national averages, and 646 dentists (0.5 per 1000 residents)[1].

The Missouri River is the principal water source in the area. The average flow is 35,715 MGD [9].

Kansas City is supplied with electric power from Missouri and Kansas. Kansas, in 1974, produced $18,200 \times 10^6$ kwh with a capacity to generate 5.8 GW. Only $16,974 \times 10^6$ kwh were sold within the state. Missouri produced $38,025 \times 10^6$ kwh with an 11 GW capacity, but sold only $30,837 \times 10^6$ kwh within the state. Both states were exporters of electric power in 1974 [10,11].

In 1977, Kansas City had a municipal elementary and high school enrollment of approximately 45,600 students. These students represent 9 percent of the 1973 municipal population [1,22].

For cultural entertainment and recreation there are three dinner theaters, 13 museums, a starlight theater, a lyric theater, a philharmonic orchestra, 49 golf courses, 27 swimming pools, 123 tennis courts, 302 public parks, and a variety of professional sports. The local media include five daily newspapers, six TV stations and 30 radio stations [1].

Kansas City International Airport serves the area, along with 49 air services, 3 bus lines, and 12 rail trunk lines [1].

There were 192,352 housing units available with 2.3 occupants per unit in Kansas City during 1970. Of this total, 1,742 units were for sale and 11,972 units were for rent [13].

ENVIRONMENT

Kansas City is located at the junction of the Kansas and Missouri Rivers [6]. The area is interspersed with more than 100 parks and numerous lakes. The municipal area is superbly designed, with gracious residential areas, and majestic elms and fountains [2,4,6].

The region experiences moderate seasonal climate variations with an average annual high temperature of 63.7°F and an average low temperature of 45.3°F. Mean wind velocity is 10.1 mph, predominantly from the southwest. Annual precipitation averages 38.98 inches [1,6,15]. The peregrine falcon is a federal endangered bird found in the Counties of Jackson and Clay [18].

The water supply is more than ample for Kansas City. Municipal and industrial use is about 106 MGD of a 210 MGD supply from the Missouri River, and there are no significant contaminants [1,6,9].

Kansas City has fair to good air quality. The city occasionally is over the 75 $\mu\text{g}/\text{m}^3$ federal requirements for suspended particulate matter. The highest value of suspended particulates in a 24-hour period is 1,151 $\mu\text{g}/\text{m}^3$, which is much greater than the National Primary Standard of 260 $\mu\text{g}/\text{m}^3$. Other pollutants, such as CO and SO₂ are within state regulation limits [14,16].

CASE #4 SCENARIO: Kansas City, Missouri/Coal Oil Slurry

In this example, a 1,200 MWe oil-fired power plant in the north section of Kansas City, Missouri, would be retrofitted to burn a coal oil slurry. The plant already has rail service and gets its cooling water from the Missouri River. Thus, no new roads, railroads, pipelines or transmission lines are required. Some modification to the pollution control equipment will probably be necessary, since coal combustion generates larger amounts of particulates and sulfur oxides.

Kansas City had a population of 675,213 in 1970. Its economy is oriented toward agriculture and manufacturing.

Bituminous coal would be mined outside the Kansas City area and delivered to the power plant by the Kansas City Southern Railroad. The slurry will be prepared on-site so that storage, agitation and additives are unnecessary. The conversion would result in an oil consumption reduction of 15,500 barrels per day, which would be compensated by 4,120 tons/day of 3.9% sulfur bituminous coal. Modifications to the boiler will cost about \$2 million, but the pollution control equipment modifications could increase this to about \$60 million. Except for increased air pollution emissions, the conversion is expected to have a minimal impact.

TABLE OF RESULTS
Case #4: KANSAS CITY, MO/Coal Oil Slurry Electric Power Generation

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	0	0	1.0	0	6.12	Percent 24-Hr SO ₂ Standard	75.8	1.00	0.17	0.170
1.7	Change in Unemployment	0	0	0.50	0	CATEGORY 6 TOTAL			2.04	1.0	0.348
CATEGORY 1 TOTAL			0	1.0	0	7.1	% Assimilation Capacity Remaining	100	0	1.0	0
2.2	Percent Increase in Policemen	0	0	0.10	0	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	0	0	0.09	0	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	0	0	0.12	0	8.1	% Habitat Area Disturbed	0	0	0	0
2.8	Percent Increase in Hospital Beds	0	0	0.10	0			--	--	--	--
2.10	Percent Increase in Dentists	0	0	0.12	0			--	--	--	--
2.12	Percent Increase in Teachers	0	0	0.08	0			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	0	0	0.10	0			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	0	0	0.10	0	CATEGORY 8 TOTAL			0	1.0	0
2.15	% Marginal Solid Waste Area Used	0	0	0.12	0	9.1	% Reduction in Panoramic View	0	0	0.50	0
2.16	% Increase in Park & Recreation Area	0	0	0.07	0	9.2	Historical & Archeological Sites	A	0	0.50	0
CATEGORY 2 TOTAL			0	1.0	0	CATEGORY 9 TOTAL			0	1.0	0
3.13	Percent Bonding Capacity Required	0	0	1.0	0	10.7	Percent Change in Tax Rate	-0.6	0	0.50	0
CATEGORY 3 TOTAL			0	1.0	0	CATEGORY 10 TOTAL			0	0.50	0
4.2	Percent Increase in Mun. Housing	0	0	0.25	0	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	0.35	0	0.50	0						
4.11	% Underdeveloped Regional Land	0	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			0	1.0	0	1	Employment/Population	0.12	0	0	
5.4	% Change in Elec. Import/Export	0	0	0.35	0	2	Community Services	0.10	0	0	
5.6	% Available Surface Water Required	0	0	0.65	0	3	Infrastructure	0.11	0	0	
CATEGORY 5 TOTAL			0	1.0	0	4	Land Use/Housing	0.11	0	0	
6.8	% Annual Particulate Standard	6.20	0.06	0.17	0.010	5	Utilities	0.08	0	0	
6.9	% Annual SO ₂ Standard	38.2	0.60	0.17	0.102	6	Air Quality	0.18	0.045	0.063	
6.10	% NO _x Concentration Margin	1.4	0.01	0.32	0.003	7	Water Quality	0.15	0	0	
6.11	% 24-Hr Particulate Standard	28.8	0.37	0.17	0.063	8	Endangered Wildlife	0.08	0	0	
						9	Aesthetics and Sites	0.07	0	0	
						10	Community Tax Revenue	(0.50)	0	0	
						SUM OF ADVERSE IMPACTS			1.00	0.045	0.063

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS CASE #4: Kansas City, MO/Coal Oil Slurry

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.063 and 0.045, respectively, indicating a negligible overall impact.
- The only category with a non-zero score is Air Quality with a score of 0.348 (prior to the application of category weights).
- No beneficial impacts are foreseen.
- The Site & Process Scores are of the order of 1/5 of the averages for the nine illustrative examples, and are the lowest Scores in the group.

MAJOR ADVERSE IMPACTS

- Air Quality: A substantial increase in the sulfur dioxide concentration and a moderate increase in the concentration of particulates are predicted.
- All other adverse impact elements have RIC Values equal to zero.

BENEFICIAL IMPACTS

- None are predicted.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score is 40% larger than the equally weighted score.

AMELIORATING ACTIONS

- Develop more efficient control of air effluents, particularly sulfur dioxide.

IMPACTS REQUIRING MORE ANALYSIS

- Air quality modeling.

References for Case #4, Kansas City, Missouri

1. *Profile of Greater Kansas City*, Missouri, Kansas City Chamber of Commerce.
2. *Community Profile: Kansas City, Kansas*, Kansas, Kansas Department of Economic Development.
3. Wofson, Stanley M. (Ed.). *The Municipal Year Book*, Washington, D. C., International City Management Association, v. 43, 1976: Sections A,D,F.
4. Delury, George E. (Ed.). *The World Almanac and Book of Facts*, New York and Cleveland, Ohio, Newspaper Enterprise Association, Inc., 1976.
5. *Framework for Development*, Kansas City, Missouri, M.A.R.C. (Mid-American Regional Council), September 1977.
6. Gerlach, Arch C. *The National Atlas of the United States of America*, Washington, D.C., United States Department of the Interior, Geological Survey, 1970.
7. Map of Population Density by Counties of the United States: 1970, Washington, D.C., U. S. Department of Commerce.
8. *Estimates and Projections Kansas City Metropolitan Region*, Kansas City, Missouri, November 1976.
9. Todd, David K. *The Water Encyclopedia*, Port Washington, N.Y., Water Information Center Inc., October 1970.
10. "Census Estimate Predicts 13 States May Gain or Lose House Strength," *Arkansas Gazette*, Little Rock, Arkansas, January 23, 1978.
11. Bailey, David J. *Statistical Year Book of the Electrical Utility Industry*, New York, Edison Electric Institute, No. 42, 1975.
12. *1970 Census of Population, Characteristics of the Population*, Washington, D.C., U.S. Department of Commerce, Social and Economic Statistics Administration, Bureau of Census, v. 1.
13. *Housing Characteristics for States, Cities and Counties*, Washington, D. C., U. S. Department of Commerce, 1973: Part 27.
14. *Monitoring and Air Quality Trends Report*, 1974, Research Triangle Park, North Carolina, U. S. Environmental Protection Agency, February 1976. (EPA-450/1-76-001)
15. Lerner, William. *Statistical Abstract of the United States*, Washington, D.C. U.S. Department of Commerce, Bureau of Census, 97th edition, July 1976.
16. Telephone Communication with George Delapp, Kansas City Air Quality Division, March 24, 1978.
17. American Hospital Association. *American Hospital Association Guide to the Health Care Field*, Chicago, Illinois, 1977.

References for Case #4 (Continued)

18. Brohn, Keefe, Sullivan, Wylie (Ed.). *Rare and Endangered Species of Missouri*, Missouri Department of Conservation and United States Department of Agriculture Soil Conservation Service, 1977. (The information obtained pertained to the counties of Jackson, Clay and Platte.
19. *Kansas City*, Topographic Map from the United States Department of the Interior Geological Survey, 1974. (NJ 15-1) (Used to obtain CEM estimates.)
20. Telephone Communication with Edward Bird, Kansas City, Missouri, Kansas City Hall, May 3, 1978.
21. Telephone Communication with Edward Jones, Kansas City, Missouri, Kansas City Assessor, May 10, 1978.
22. Telephone Communication with Eleanor Bradley, Kansas City, Missouri, Board of Education Communications Department, May 19, 1978. Numbers of teachers are approximations.
23. Year-round vacant units only. (See Reference 13.)
24. CEM estimate, using rental and homeowner vacancy rates for year-round units. (See Reference 13.)
25. Persons per occupied unit, not necessarily year-round. (See Reference 13.)
26. Telephone Communication with Mr. McMurty, Kansas City Laboratory Service, Kansas City, Missouri, March 29, 1978.
27. CEM estimate.
28. *Annual Financial Report, 1977, The City of Kansas City, Missouri*, Kansas City, Missouri, Department of Finance, No. 103, 1977.
- 29.. Telephone communication with Darrel Clark, Chief of General Planning, City Planning Office, Kansas City, Missouri, June 6, 1978.

CASE #5: BLOOMINGTON, ILLINOIS

DEMOGRAPHICS

Bloomington, located in McLean County, had a population of 41,409 in 1975 and a population density of 3,016 people/sq mi [4]. In the 15-year period 1960-1975, population increased 14 percent. In 1975, four percent of the residents were non-white, 30 percent were under 18 years of age, and 44 percent (18,065) of the residents were in the potential working age group [3].

LAND

McLean County's 1,182 total sq mi are 16 percent residential, 11 percent industrial, commercial, public or semi-public, and a very large percent (73%) of the land is vacant or agricultural [4,16,17].

ECONOMICS

In 1976, there were fifty industries in McLean County and the total labor force was 57,887 [3]. Unemployment was approximately 3.1 percent or 1,794 in 1975 [11]. Manufacturing and wholesale/retail are among the largest employment sectors, with government, mining and agriculture being much less significant. This area does, however, lead the nation in corn and soybean production. Bloomington's per capita income was \$5,171 in 1974, which was a 50.3 percent increase from 1969 and was close to the national average of \$5,486 for 1974. Financial services are provided by six banks and two savings and loan associations [4].

The total revenue for Bloomington in 1976-1977 was \$12,456,374. Property tax accounted for 37.6 percent of this revenue. The local mill rate is approximately 50 [26,27,28].

SOCIAL

Bloomington is governed by an elected Mayor, a City Council and a City Manager selected by the Council [4]. Primary civil services are provided by 66 policemen (1.6 per 1000 residents) and 65 firemen (1.6 per 1000 residents). The police figure is slightly less than the national average of 2.1 per 1000 residents, and the firemen equal the national average [1]. Medical services are supported by three area hospitals [2,3].

The municipal water supply is drawn from two area lakes with a capacity to supply 18 MGD. Current treatment load is 11 MGD with a capacity to treat 25 MGD. An additional 8 MGD capacity is available from 14 area wells, currently being utilized at a 4 MGD rate [4].

In 1974, the State of Illinois had an electric generating capacity of 24.8 GW, but generated only $91,453 \times 10^6$ kwh. Of the amount generated, $83,485 \times 10^6$ kwh was sold intrastate, making Illinois a net exporter of power [13].

Cultural aspects of the area include an amateur musical club, art association, symphony guild and community players. For recreation and entertainment, the area supports five movie theaters, three bowling alleys, 19 tennis courts, two public pools and one public golf course [4].

In 1977, Bloomington had a municipal elementary and high school enrollment of approximately 22,163 students. These students represented 19 percent of the municipal population, based on CEM's 1977 population estimate [24].

Aside from six Federal and State highways servicing Bloomington, access to the region is available through four railroads, and Amtrak, three bus lines, and one airline [3].

In 1970, there were 14,459 housing units in Bloomington. The median number of rooms per unit was 4.8 and the average number of occupants was 2.3. Additional housing capacity of approximately 18,868 units exists in the remainder of McLean County. There was an average of 72 units for sale and 364 for rent in 1970 [8].

ENVIRONMENT

McLean County has a land surface form which is mostly gently sloping, smooth plains with a 171-day growing season. The mean annual precipitation is 36.7 inches and the mean average wind speed is 11 mph [22]. There are no endangered animals from the federal list known to be present in McLean County [21].

Drinking water is supplied by Lake Bloomington, Lake Evergreen (18 MGD capacity), and 14 wells (8 MGD capacity). The Bloomington sewage treatment plant has a capacity for 32 MGD and peak usage of 18 MGD [3,25].

The air quality is good in Bloomington. For a 24-hour period, the highest value of suspended particulates is $148 \mu\text{g}/\text{m}^3$, which is less than the National Primary Standard of $260 \mu\text{g}/\text{m}^3$. Other pollutant levels are very low [7,29].

CASE #5 SCENARIO: Bloomington, Illinois/MHD Electric Power Generation

The site chosen for a hypothetical magnetohydrodynamic (MHD) power plant is about 10 miles north of Bloomington. Illinois bituminous coal would be delivered on the Illinois Central Gulf Railroad and a new 2-mile spur leading to the plant. New transmission lines would extend four miles West to the existing main power line. Water would be supplied through a 2-mile pipeline from the Mackinaw River. A new 5-mile road will connect the site to U.S. Route 51.

Bloomington had a population of 41,407 in 1975. A considerable amount of industry is located within the city limits.

Commercial MHD power plants would be the most efficient means of electric power generation yet devised. It is anticipated that a 1200 MWe plant, such as the one proposed in this example, would consume 20 percent less coal than the most efficient conventional coal fired power plants -- 9040 tons/day in this example. The plant would also require 11.5 million gallons of water daily for cooling. Construction would begin four years after the final decision to build is made and would take six years to complete. The plant is expected to provide jobs for 100 people on site and 480 people at mines in nearby areas.

TABLE OF RESULTS
Case #5: BLOOMINGTON, IL/MHD Electric Power Generation

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	9.5	0.04	1.0	0.040	6.12	Percent 24-Hr SO ₂ Standard	1.3	0.01	0.17	0.002
1.7	Change in Unemployment	-33.3	-1.00	0.40	-0.400	CATEGORY 6 TOTAL			0.45	1.0	0.085
CATEGORY 1 TOTAL			0.04	1.0	0.040	7.1	% Assimilation Capacity Remaining	87.4	0.02	1.0	0.02
2.2	Percent Increase in Policemen	9.7	0.10	0.10	0.010	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	9.5	0.09	0.09	0.008	CATEGORY 7 TOTAL			0.02	1.0	0.02
2.6	Percent Increase in Doctors	9.7	0.03	0.12	0.004	8.1	% Habitat Area Disturbed	--	--	--	--
2.8	Percent Increase in Hospital Beds	9.6	0.07	0.10	0.007			--	--	--	--
2.10	Percent Increase in Dentists	9.6	0.07	0.12	0.008			--	--	--	--
2.12	Percent Increase in Teachers	9.4	0.03	0.08	0.002			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	10.5	0.04	0.10	0.004			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	4.5	0.02	0.10	0.002	CATEGORY 8 TOTAL			0	1.0	0
2.15	% Marginal Solid Waste Area Used	3.3	0.01	0.12	0.001	9.1	% Reduction in Panoramic View	0.3	0.01	0.50	0.005
2.16	% Increase in Park & Recreation Area	15.5	0.11	0.07	0.009	9.2	Historical & Archeological Sites	A	0.01	0.50	0.005
CATEGORY 2 TOTAL			0.57	1.0	0.055	CATEGORY 9 TOTAL			0.02	1.0	0.010
3.13	Percent Bonding Capacity Required	186	1.00	1.0	1.000	10.7	Percent Change in Tax Rate	-27.2	-0.34	0.40	-0.136
CATEGORY 3 TOTAL			1.00	1.0	1.000	CATEGORY 10 TOTAL			-0.34	0.40	-0.136
4.2	Percent Increase in Mun. Housing	10.3	0.09	0.25	0.023	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	118	1.00	0.50	0.500						
4.11	% Underdeveloped Regional Land	0.3	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			1.09	1.0	0.523	1	Employment/Population	0.12	0.004	0.005	
5.4	% Change in Elec. Import/Export	-85.4	-0.90	0.20	-0.180	2	Community Services	0.10	0.006	0.006	
5.6	% Available Surface Water Required	36.9	0.25	1.0	0.25	3	Infrastructure	0.11	0.111	0.110	
CATEGORY 5 TOTAL			0.25	1.0	0.25	4	Land Use/Housing	0.11	0.040	0.058	
6.8	% Annual Particulate Standard	18.0	0.19	0.17	0.032	5	Utilities	0.08	0.028	0.020	
6.9	% Annual SO ₂ Standard	3.4	0.03	0.17	0.005	6	Air Quality	0.18	0.010	0.015	
6.10	% NO _x Concentration Margin	6.1	0.06	0.32	0.019	7	Water Quality	0.15	0.002	0.003	
6.11	% 24-Hr Particulate Standard	15.6	0.16	0.17	0.027	8	Endangered Wildlife	0.08	0	0	
						9	Aesthetics and Sites	0.07	0.002	0.001	
						10	Community Tax Revenue	(0.50)	(0.113)	(-0.136)	
						SUM OF ADVERSE IMPACTS			1.00	0.201	0.216

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS

CASE #5: Bloomington, IL/MHD Electric Power Generation

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.216 and 0.201, respectively, indicating a moderate overall impact.
- The largest contributing category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- Significant benefits are predicted in three categories.
- The Site & Process Scores are about 20% lower than the averages for the nine examples.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity required is almost double the available portion of the legal limit.
- Land Use & Housing: The municipal land requirement exceeds the under-developed land available.

BENEFICIAL IMPACTS

- Employment and Population: Unemployment in the county would be cut by one-third.
- Utilities: The amount of electricity exported by the state would nearly double.
- Community Tax Revenue: The overall municipal tax rate would be reduced by about one-fourth.

EFFECT OF VARIABLE WEIGHTING

- The variable weighted Site & Process Score exceeds the uniformly weighted score by about 8%.

AMELIORATING ACTIONS

- Industrial and/or governmental funding to expand the municipal infrastructure is needed.
- A larger fraction of the process related industries might be located outside the municipal boundaries.

IMPACTS REQUIRING MORE ANALYSIS

- Land use requirements.
- Availability of adequate water.
- Tax revenues generated.
- Air quality modeling.

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18. *Climate Atlas of the United States*, U. S. Department of Commerce, Environmental Services Administration, reprinted by National Oceanic and Atmospheric Administration, 1974.
19. Telephone Communication with Richard Darnall, Bloomington, Illinois, Superintendent of Schools' Office, May 22, 1978.
20. Year-round vacant units only. (See Reference 8.)
21. Letter from John Cole, District Biologist with Illinois Department of Conservation, May 21, 1978. (The information given pertained to McLean County.)
22. Persons per occupied unit not necessarily year-round. (See Reference 8.)
23. CEM estimate, using rental and homeowner vacancy rates for year-round units. (See Reference 8.)
24. CEM estimate, obtained by using overall student:teacher ratio. (See Reference 8.)
25. CEM estimate.
26. Telephone Communication with Vera Hanley, Bloomington, Illinois, McLean Deputy County Clerk, McLean County, Tax Extension Office, May 11, 1978.
27. Telephone Communication with Shirley Neal, Bloomington, Illinois, Bloomington Finance Department at the City Hall.
28. *Annual Financial Report of the City of Bloomington, Illinois, for the Fiscal Year May 1, 1976 to April 30, 1977*, issued by the Bloomington Finance Department.
29. Telephone Communication with Robert Stortzun, Illinois Air Pollution Control, Champaign, Illinois, April 7, 1978.
30. Telephone Communication with Dave Gerard, Illinois Environmental Protection Agency, Water Control Division, Springfield, Illinois, April 3, 1978.
31. Telephone Communication with Herman Driks, City Building and Planning Office, Rawlins, Wyoming, June 6, 1978.

CASE #6: VERNAL, UTAH

DEMOGRAPHICS

In 1977, the estimated population for Vernal was 6,700 [3]. The town is located in Uintah County, which had an estimated 1975 population of 17,300 [1]. The municipal population increased 6.9 percent in the decade of the 1960's, and the County had a 9.5 percent increase during the same period [3]. The 1976 population density of Uintah County was about 3.9 people/sq mi. In 1974, 7.4 percent of Uintah's population was under 18 years of age, 6.9 percent was over 65 years old, and 11 percent was nonwhite [1].

LAND

The total land area of Uintah County is 4,472 sq mi [1]. Of this land, 92.5 percent is for grazing; 2.5 percent is given over to cultivated crops and 4.3 percent is mining and extraction or derelict [1,13].

ECONOMICS

The economy of Vernal is based on farming, livestock, lumber, honey, vast mineral resources and tourism [2]. Construction, manufacturing, wholesale/retail and services are the chief areas of employment for Vernal. In 1975, Uintah County had a labor force of 7,190 (42% of the population). Unemployment was 4.9 percent (425). The County's per capita income was \$2,867 in 1976, which is substantially lower than the \$5,834 (1975) national average. Regional financial services are provided by three banks and two savings and loan associations [3].

The total revenue for Vernal in 1976-1977 was \$2,120,000. Property taxes accounted for 17.9 percent (20% assessed) of this revenue. The local mill rate is approximately 50 [23].

SOCIAL

Vernal and Uintah County are governed by a Manager-Council system, which has three County Commissioners, and Legislative and Chief Administrators [2]. Primary civil services are provided by 19 city policemen, six county law officers (2.8 law officers per 1000 people), which is slightly higher than the national average of 2.1 policemen per 1000 residents, and a volunteer fire department [1,3]. Medical services are supported by a modern County Hospital with 31 beds and seven physicians (1.0 per 1000 residents), which is slightly less than the national average of 1.7 per 1000 population [3].

The primary sources of drinking water in Vernal are wells. Water usage in Vernal peaks at 2.5 MGD and the area has a 3.0 MGD capacity. The wastewater peak usage is 2.7 MGD with a 2.7 MGD treatment capacity [13].

Electric power is supplied by Utah Power and Light. The State of Utah, in 1977, generated $3,999 \times 10^6$ kwh and sold 7.122×10^6 kwh with a total generating capacity of 1.2 GW, making Utah a net importer of electric power [11].

In 1977, Vernal had a municipal elementary and high school enrollment of approximately 3,787 students. These students represented 56 percent of the 1977 municipal population [16].

Cultural and recreational facilities include a gallery of arts, potters' guild, community concert and three movie theaters [2]. Recreational activities revolve around golf, swimming, bowling, skiing, and many other outdoor sports [2]. A weekly newspaper, cable TV, and two radio stations serve the region [3]. Vernal has two buslines, a municipal airport and seven interstate freight services. Rail service is not available [3].

In 1970, there were 1,283 housing units in Vernal. The median number of rooms per housing unit was 5.0 and the average number of occupants per unit was 3.1. There were approximately nine housing units for sale and 41 for rent [6].

ENVIRONMENT

In the northern part of Uintah County, there are high mountains with less than 20 percent of the land surface sloping gently. The central region has timberlands, and southern Uintah has low mountains. The vegetation includes a lodgepole pine forest region and pinyon-juniper forests. The most abundant vegetation type in the region is saltbush-greasewood [7].

Area climate exhibits wide seasonal variation with average temperatures ranging from below 30°F in the winter to around 70°F in the summer. Annual rainfall in Vernal is 6.88 inches, and in Uintah, 8.52 inches [2,3].

Natural resources include tar sands (richest deposit in the U.S.), oil shale, natural gas, phosphate, gilsonite, pure asphalt deposits, lumber, and grazing lands [1]. Deer, elk, pheasant, ducks, geese, chukar, bear and mountain lion are some of the area's wildlife [8]. Nationally endangered animals known to be living within 50 miles of Vernal are the humpback chub and Colorado squawfish, which live in the Green River, and the mammalian black-footed ferret [21].

There are many areas of historical significance in the Vernal region. Prehistoric Indian cliff murals are located 10 miles from the center of town. A museum was established to serve as a focal point for the preservation of pioneer relics and a monument to the history of the area's settlement [8].

In Vernal, the only stream pollution problems are in localized areas near waste treatment discharge. Ashley Creek violates the standards for coliform, dissolved oxygen and biochemical oxygen demand. The sewage treatment plant on Ashley Creek is 20 years old, overloaded sometimes and not well maintained. The EPA secondary requirements, however, are usually met. A new sewage treatment plant, using a lagoon system, is planned for construction in two to three years [13].

Air quality in Vernal is good. In 1977, particulate levels had a geometric mean of 32 $\mu\text{g}/\text{m}^3$ and a highest reading of 190 $\mu\text{g}/\text{m}^3$, which is much lower than the Primary Standard of 260 $\mu\text{g}/\text{m}^3$ and a little higher than the Secondary Standard of 150 $\mu\text{g}/\text{m}^3$. All other forms of air pollution are very low [15,24].

CASE #6 SCENARIO: Vernal, Utah/Tar Sands Conversion

A tar sands conversion plant would be constructed near Asphalt Ridge, five miles south of Vernal. The tar sands would be removed from the ridge and transported to the plant by a one mile long conveyor belt. Water would be drawn by pipeline from the Green River four miles to the south. A two mile extension of the main road leading to Vernal would be necessary.

Vernal, with a 1975 population of 7,300, has an economy based largely on agriculture and natural resource extraction and processing.

Synchrude production of 50,000 barrels per day would be accomplished by a process similar to the Hot Water Extraction Process used by existing plants in Alberta, Canada. By-product low Btu gas would be sufficient for all the internal energy needs of the facility. Large quantities of materials are involved in tar sands conversion: 140,000 tons/day would be removed from Asphalt Ridge and 123,000 tons/day of spent sand would be generated as a waste. In addition, seven million gallons of water would be consumed daily. The tailings pond in which the spent sand is separated from water would eventually cover about three square miles. Construction would begin in three years and be completed five years later. The plant will operate for 30 years with about 1160 employees.

TABLE OF RESULTS
Case #6: VERNAL, UT/Tar Sands Conversion

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	209	1.00	1.0	1.00	6.12	Percent 24-Hr SO ₂ Standard	17.2	0.19	0.17	0.032
1.7	Change in Unemployment	-33.3	1.00	1.00	1.000	CATEGORY 6 TOTAL			1.73	1.0	0.350
CATEGORY 1 TOTAL			1.00	1.0	1.00	7.1	% Assimilation Capacity Remaining	99.7	0	1.0	0
2.2	Percent Increase in Policemen	166	1.00	0.10	0.100	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	∞	1.00	0.09	0.090	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	243	1.00	0.12	0.120	8.1	% Habitat Area Disturbed	2.7	0.06	0.34	0.020
2.8	Percent Increase in Hospital Beds	199	1.00	0.10	0.100	8.2	Endangered Aquatic Species	2.0	0.08	0.33	0.026
2.10	Percent Increase in Dentists	207	1.00	0.12	0.120	8.2	Endangered Aquatic Species	2.0	0.08	0.33	0.026
2.12	Percent Increase in Teachers	41.1	0.96	0.08	0.077			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	335	1.00	0.10	0.100			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	∞	1.00	0.10	0.100	CATEGORY 8 TOTAL			0.22	1.0	0.072
2.15	% Marginal Solid Waste Area Used	70.6	0.72	0.12	0.86	9.1	% Reduction in Panoramic View	2.5	0.03	0.50	0.015
2.16	% Increase in Park & Recreation Area	199	1.00	0.07	0.070	9.2	Historical & Archeological Sites	D	0.70	0.50	0.350
CATEGORY 2 TOTAL			9.68	1.0	0.962	CATEGORY 9 TOTAL			0.73	1.0	0.365
3.13	Percent Bonding Capacity Required	3123	1.00	1.0	1.00	10.7	Percent Change in Tax Rate	11.5	0.02	1.0	0.02
CATEGORY 3 TOTAL			1.00	1.0	1.00	CATEGORY 10 TOTAL					
4.2	Percent Increase in Mun. Housing	349	1.00	0.25	0.250	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	217	1.00	0.50	0.506						
4.11	% Underdeveloped Regional Land	0.5	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			2.00	1.0	0.750	1	Employment/Population	0.11	0.100	0.110	
5.4	% Change in Elec. Import/Export	2.5	0	0.35	0	2	Community Services	0.09	0.097	0.087	
5.6	% Available Surface Water Required	34.2	1.00	0.65	0.650	3	Infrastructure	0.10	0.100	0.100	
CATEGORY 5 TOTAL			1.00	1.0	0.650	4	Land Use/Housing	0.10	0.067	0.075	
6.8	% Annual Particulate Standard	21.6	0.23	0.17	0.039	5	Utilities	0.07	0.050	0.046	
6.9	% Annual SO ₂ Standard	36.4	0.55	0.17	0.094	6	Air Quality	0.16	0.035	0.056	
6.10	% NO _x Concentration Margin	33.2	0.46	0.32	0.147	7	Water Quality	0.14	0	0	
6.11	% 24-Hr Particulate Standard	23.8	0.30	0.17	0.051	8	Endangered Wildlife	0.07	0.007	0.005	
						9	Aesthetics and Sites	0.06	0.037	0.022	
						10	Community Tax Revenue	0.10	0.002	0.002	
						SUM OF ADVERSE IMPACTS			1.00	0.495	0.503

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS CASE #6: Vernal, UT/Tar Sands Conversion

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.503 and 0.495 respectively, indicating a major overall impact.
- The largest contributing categories are Employment and Population and Infrastructure with category scores of 1.0 and Community Services with a score of 0.962 (prior to the application of category weights).
- The only beneficial impact predicted is a decrease in unemployment.
- The Site & Process Scores are the largest obtained and are about twice the averages of the nine illustrative examples.
- The alternative proposed in this scenario might be rejected on the basis of a preliminary analysis.

MAJOR ADVERSE IMPACTS

- Employment and Population: The population of Vernal would more than triple.
- Infrastructure: The bonding capacity required is more than 30 times the available portion of the legal limit.
- Community Services: Major impacts are predicted for all ten elements.
- Land Use & Housing: A large number of new housing units would have to be built and municipal land requirements are more than twice the available underdeveloped land.
- Utilities: About one-third of the surface water available to Vernal would be needed.
- Aesthetics and Sites: The plant is located about 10 miles from Dinosaur National Monument, and may adversely affect tourist appeal.

BENEFICIAL IMPACTS

- Employment and Population: A one-third reduction in county unemployment is predicted, but this amounts to only 141 jobs.

EFFECT OF WEIGHTING

- The Site & Process Scores do not differ significantly.

AMELIORATING ACTIONS

- New communities could be started in the area.
- Industrial and/or governmental funding to support the expansion of the municipal infrastructure and to finance housing construction is needed.
- The acquisition of additional water rights may be necessary.

IMPACTS REQUIRING MORE ANALYSIS

- The largest uncertainties in this example are in the Air Quality, Endangered Wildlife and Community Tax Revenue categories.

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16. Telephone Communication with Frank Andreason, Vernal, Utah, Vernal Superintendent of Schools Office, May 19, 1978. (Estimate)

References for Case #6 (continued)

17. CEM estimate, using rental and homeowner vacancy rates for year-round units.
(See Reference 6.)
18. Year-round vacant units only. (See Reference 6.)
19. Rooms per year-round unit. (See Reference 6.)
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22. *Status of Selected Animal Species in Utah*, prepared by Utah Division of Wildlife Resources, October 1977.
23. Telephone Communication with Michelle Aycock, Vernal, Utah, Vernal City Treasurer at the Vernal City Office, May 4, 1978.
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26. Lerner, William. *Statistical Abstract of the United States 1976*, Washington, D.C., U.S. Department of Commerce, Bureau of the Census, 97th Edition, July 1976.
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CASE #7: BISMARCK, NORTH DAKOTA

DEMOGRAPHICS

Bismarck, the capitol of North Dakota, is located in Burleigh County (Bismarck SMSA). The city has been in a period of rapid growth, with a 1977 population of 41,500 [1]. Population density within the city was 2,842/sq mi and ranged from 10 to 49 people/sq mi in the more rural areas of the SMSA. Only one percent of this population is nonwhite and 54 percent is between the ages of 18 and 65 [2,5].

LAND

The total land area of Bismarck is 14.6 sq mi. Numerous parks take up 2.22 sq mi (15%) of this land [1,3,4].

Croplands cover 323.44 sq mi (20%) of Burleigh County and much of the land is used for grazing the county's 89,000 head of livestock. Lakes and reservoirs also cover a significant area of land in the county [1].

ECONOMICS

Surrounded by farmlands, a major sector of Bismarck's economy rests on agriculture, farm equipment manufacturing, and farm products processing. Printing and concrete products manufacturing are also major industries in the city. State government activity also contributes to economic growth [3].

The non-agricultural employment in Bismarck is 20,330. Most of these people are involved with government work, services, and wholesale/retail trade [3,6]. The per capita income was \$3,524 (1972) which was lower than the national norm of \$4,537 (1972) [2].

Financial services within Bismarck are provided by five banks, five building and loan associations, and four savings and loan associations [1,3].

The total revenue for Bismarck in 1977 was \$29,930,785. Property tax accounted for 10 percent of this revenue. The local mill rate is approximately 269.85 [21].

SOCIAL

Bismarck has a City-Commission form of government, with a Mayor. Five Commissioners, elected directly by the people, collectively serve as a legislative body, each heading one or more administrative departments [2,3]. Primary civil services are provided by 70 full-time policemen (1.7 per 1000 residents) and 45 full-time firemen (1.1 per 1000 residents) [1]. These figures are slightly lower than national averages of 2.1 and 1.6 (policemen and firemen/1000 residents), respectively [1].

Medical services are supported by two hospitals with a 453 bed capacity, 75 doctors, (1.8 per 1000 residents) which is almost equal to the national average of 1.7 per 1000 residents, and 23 dentists (0.6 per 1000 residents) [1].

The municipal water supply is drawn from the Missouri River, which runs adjacent to the city. The river flow rate is about 13.6 MGD [13]. Present treatment plant capacity is 22.5 MGD, while present consumption is 6.4 MGD [13,15]. An aerated treatment

pond presently handling 4.5 MGD of community wastewater had a capacity of 7.5 MGD. Assuming that an average person consumes 134 gal daily, 7.5 MGD would be sufficient to serve 55,000. Solid wastes are disposed by sanitary landfill [1,13,15].

An abundant supply of electric power is generated by the Garrison Dam, which is adjacent to the city. Power generated within North Dakota in 1974 was $8,475 \times 10^6$ kwh with a capacity of 1.3 GW. The total amount sold within the state was only $3,365 \times 10^6$ kwh, which means that the area was a net exporter of electricity [8].

In 1977, Bismarck had a municipal elementary and high school enrollment of approximately 8,821 students. These students represented 21 percent of the 1977 municipal population [1,10].

Culturally, the Bismarck municipal area supports a Civic Center, six theaters, concert groups and a symphony orchestra. Three regional libraries contain 178,200 volumes [1,3]. Recreation is provided by 30 parks, including a zoo and campground within the city limits, three golf courses, an archery range, a race track and a YMCA building [1,3]. Snowmobiling is popular and lakes around the city are stocked regularly for fishing [1,3].

A daily newspaper, five radio stations and two TV stations operate in Bismarck and cable TV is available [1]. Three airlines serve the city, as well as both passenger and freight rail companies, truck lines and bus lines. [1].

In 1970, there were 11,156 housing units in Bismarck. The median number of rooms per unit was 4.6 and the average number of occupants per unit was 2.8. There was an average of 104 units available for sale and 320 for rent (CEM estimate)[9].

ENVIRONMENT

Bismarck derives visual appeal from its spacious riverside parks and from additional parklands interspersed throughout the city. It is surrounded by numerous lakes, reservoirs, and many acres of tranquil grazing and croplands. One of the main routes for the northern flight of ducks and geese lies east of the city [1,3].

The climate is cool and rather dry, with a mean annual temperature of 41.4°F and an average annual rainfall of 16.15 inches. The mean wind velocity is 11 mph from the northwest [1].

The primary natural resources in Bismarck are coal (lignite located in the northwest section of the state), sand and gravel. Rainbow trout are abundant in the Garrison Dam Reservoir [1]. Within the 50 mile radius of Bismarck live the nationally endangered black-footed ferret, bald eagle, and northern swift fox [8].

Bismarck shares most of its water supply with the City of Mandan. The Missouri River and minor tributaries are the principal sources in the area. In 1977, water treatment plants were upgraded in Bismarck. Mandan is building a new facility in 1978. Water quality is presently meeting secondary standards. An oil refinery and a coal fired electric generating plant both operate upriver, causing no serious pollution problems [15].

Bismarck's air quality is fair to good. Maximum 24-hr levels of suspended particulates and SO_2 reach $246 \mu\text{g}/\text{m}^3$ and $2 \mu\text{g}/\text{m}^3$, corresponding to National Standard Values of $260 \mu\text{g}/\text{m}^3$ and $365 \mu\text{g}/\text{m}^3$, respectively [11].

CASE #7 SCENARIO: Bismarck, North Dakota/Lignite Liquefaction

This example examines a hypothetical lignite liquefaction plant six miles southeast of Bismarck. A one mile railroad spur to the southeast would be built to connect the facility with the Soo Line Railroad, over which the lignite feed would be delivered. Water would be piped from the Missouri River at a point 2.5 miles south of the plant, and an electrical power line connection would extend three miles to the northeast. A four mile road would be constructed to connect the site to an existing road leading to Bismarck.

Bismarck had a population of 41,500 in 1977. It is a rapidly growing city with an economy based on agriculture. Being the state capital, it has many government workers.

The Donor Solvent Process, which applies many conventional petroleum refining techniques to coal liquefaction, has been chosen for this example. To produce 50,000 barrels per day of synthetic petroleum products, a plant using this process would consume about 30,400 tons of lignite and eight million gallons of water daily. Construction would commence 2 years after a final decision to build, and start-up would occur five years later. The plant is expected to have a 25 year operating life and would provide 500 jobs on-site and 300 jobs at surface lignite mines in the Bismarck region.

TABLE OF RESULTS

Case #7: BISMARCK, ND/Lignite Liquefaction

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	23.6	0.13	1.0	0.130	6.12	Percent 24-Hr SO ₂ Standard	32.1	0.43	0.17	0.073
1.7	Change in Unemployment	-33.3	-1.00	0.50	-0.500	CATEGORY 6 TOTAL			1.49	1.0	0.275
CATEGORY 1 TOTAL			0.13	1.0	0.130	7.1	% Assimilation Capacity Remaining	99.9	0	1.0	0
2.2	Percent Increase in Policemen	26.8	0.43	0.10	0.043	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	26.6	0.42	0.09	0.038	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	23.4	1.00	0.12	0.120	8.1	% Habitat Area Disturbed	6.0	--	--	--
2.8	Percent Increase in Hospital Beds	24.1	1.00	0.10	0.100	8.1	% Habitat Area Disturbed	0	--	--	--
2.10	Percent Increase in Dentists	23.6	1.00	0.12	0.120	8.1	% Habitat Area Disturbed	6.0	--	---	--
2.12	Percent Increase in Teachers	19.9	0.21	0.08	0.017			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	11.0	0.05	0.10	0.005			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	88.3	0.97	0.10	0.097	CATEGORY 8 TOTAL			0.15	1.0	0.15
2.15	% Marginal Solid Waste Area Used	9.1	0.03	0.12	0.004	9.1	% Reduction in Panoramic View	2.7	0.03	0.50	0.015
2.16	% Increase in Park & Recreation Area	17.1	0.80	0.07	0.056	9.2	Historical & Archeological Sites	D	0.70	0.50	0.350
CATEGORY 2 TOTAL			5.91	1.0	0.600	CATEGORY 9 TOTAL			0.73	1.0	0.365
3.13	Percent Bonding Capacity Required	216	1.00	1.0	1.000	10.7	Percent Change in Tax Rate	-49.0	-1.00	0.50	-0.500
CATEGORY 3 TOTAL			1.00	1.0	1.000	CATEGORY 10 TOTAL			-1.00	0.5	-0.500
4.2	Percent Increase in Mun. Housing	29.5	1.00	0.25	0.25	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	225	1.00	0.50	0.50						
4.11	% Underdeveloped Regional Land	0.3	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			2.00	1.0	0.75	1	Employment/Population	0.12	0.014	0.016	
5.4	% Change in Elec. Import/Export	1.3	0	0.35	0	2	Community Services	0.10	0.066	0.060	
5.6	% Available Surface Water Required	1.5	0.04	0.65	0.026	3	Infrastructure	0.11	0.111	0.110	
CATEGORY 5 TOTAL			0.04	1.0	0.026	4	Land Use/Housing	0.11	0.074	0.083	
6.8	% Annual Particulate Standard	12.0	0.12	0.17	0.020	5	Utilities	0.08	0.002	0.002	
6.9	% Annual SO ₂ Standard	27.2	0.35	0.17	0.060	6	Air Quality	0.18	0.055	0.050	
6.10	% NO _x Concentration Margin	13.3	0.14	0.32	0.045	7	Water Quality	0.15	0	0	
6.11	% 24-Hr Particulate Standard	33.2	0.45	0.17	0.077	8	Endangered Wildlife	0.08	0.017	0.012	
						9	Aesthetics and Sites	0.07	0.041	0.026	
						10	Community Tax Revenue	(0.50)	(-0.500)	(0.500)	
						SUM OF BENEFICIAL IMPACTS		1.00	-1.000	-1.000	
						SUM OF ADVERSE IMPACTS		1.0	0.380	0.359	

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS CASE #7: Bismarck, ND/Lignite Liquefaction

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.359 and 0.380 respectively, indicating a significant overall impact.
- The largest contributing category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- Substantial declines in county unemployment and the municipal tax rate are predicted.
- The Site & Process Scores are the third largest of and about 40% more than the average of the nine case studies.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity required is more than twice the available portion of the legal limit.
- Land Use & Housing: The municipal land requirement is more than double the amount available and a substantial number of new housing units would be needed.
- Community Services: Large impacts are projected for doctors, hospital beds, dentists, wastewater treatment and park and recreational areas.
- Aesthetics and Sites: Locating the plant within viewing distance of two historic sites may adversely affect tourism.

BENEFICIAL IMPACTS

- Employment and Population: Unemployment in the county would be reduced by one-third.
- Community Tax Revenue: The municipal tax rate could be reduced to half its current level.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score is about 5% less than uniformly weighted score.

AMELIORATING ACTIONS

- Industrial and/or governmental funding to expand the municipal infrastructure is needed.
- Heavy advance recruiting of doctors and dentists may prevent shortages from developing.
- Advance construction or expansion of a hospital and the wastewater treatment plant is desirable.
- A larger fraction of the incoming population might be located outside the municipal boundaries, thereby reducing the demand for municipal residential land.

IMPACTS REQUIRING MORE ANALYSIS

- Air quality modeling.
- Effect of the development on endangered wildlife.
- Alternative methods for estimating the population increase might be tried, and the socioeconomic impacts reevaluated if a significantly different value is obtained.

References for Case #7, Bismark, North Dakota

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2. Wofson, Stanley M. (Ed.). *The Municipal Year Book*, Washington, D.C., International City Management Association, v. 43, 1976, Sections A, D, F.
3. *Bismark, North Dakota Statistical Review*, Bismark Area Chamber of Commerce.
4. *1970 Census of Population, Characteristics of the Population*, Washington D.C., U.S. Department of Commerce, Social and Economical Statistics Administration Bureau of Census, v.1.
5. *Comparative Economic Indicators*, Bismark, North Dakota, Bismark Area Chamber of Commerce, January 1977.
6. *North Dakota Industrial Location Facts*, North Dakota Chamber of Commerce.
7. *Census Estimate Predicts 13 States May Gain or Lose House Strength*, *Arkansas Gazette*, Little Rock, Arkansas, January 23, 1978.
8. Bailey, David J. *Statistical Year Book of the Electrical Utility Industry*, New York, Edison Electric Institute, No. 42, 1975.
9. *Housing Characteristics for States, Cities and Counties*, Washington D.C., U.S. Department of Commerce, 1973: Part 36.
10. *General Information for Prospective New Residents*, Bismark area Chamber of Commerce.
11. *Monitoring and Air Quality Trends Report*, 1974, Research Triangle Park, North Carolina, U.S. Environmental Protection Agency, February 1976. (EPA-450/1-76-001)
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15. Phone conversation with the North Dakota Department of Health.
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17. Grouby, Barbara H. (Ed.). *The County Year Book, 1977*, Washington, D.C., National Association of Counties and International City Management Association, 1977.

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21. Telephone Communication with Mel Goetz, Bismarck City Assessor, Bismarck City Hall, May 11, 1978.
22. Year-round vacant units only. (See Reference 9.)
23. Persons per occupied unit, not necessarily year-round. (See Reference 9.)
24. CEM estimate, using rental and homeowner vacancy rates for year-round units. (See Reference 9.)
25. CEM estimate.
26. Telephone Communication with Bill Wocken, Planning Director, City Planning Office, Bismarck, North Dakota, June 6, 1978.

CASE #8: FARMINGTON, NEW MEXICO

DEMOGRAPHICS

In 1970, Farmington's population was 21,979 [3]. This represented a 7.6 percent decline over the decade of the Sixties. The 1977 estimates show a 68 percent increase in municipal population over the last seven years to 37,000 [20]. This was primarily the result of energy-related activities. In 1970, 8 percent of the population was nonwhite, 9 percent under 18, and 5 percent over 65 years old. The 1977 population density in Farmington was 1947 people/sq mi [1,2].

LAND

The land area of Farmington is 19 sq mi, which is 0.4 percent of the 5,500 sq mi area of San Juan County [2,3].

Within San Juan County, roughly half the area is part of the Navajo Reservation lands. Six percent of the Navajo land in the county is being developed by the Bureau of Reclamation for a massive irrigation project [5]. Approximately 20 percent of the Farmington municipal area is residential, 20 to 25 percent is industrial, 8 percent is parks and 50 percent of the land is vacant [2,18]. Should the town need additional land, it could easily expand.

ECONOMICS

Farmington's economy depends largely on small farming, oil and natural gas recovery, petroleum processing, and electric power generation [2]. The total labor force for 1976 in San Juan County was 25,515 and the unemployment rate in the county was 10.3 percent or 2,628 [4,7]. Per capita income in Farmington was \$6,060 in 1977, and in San Juan County, \$4,205 in 1975. These figures were slightly lower (for San Juan County) than the national norm of \$5,834 in 1975 [7].

The total revenue for Farmington in 1976-1977 was \$23,570,000. Property tax accounted for 0.5 percent (33.3% assessed) of this revenue. The local mill rate is approximately 37 [21].

SOCIAL

Farmington has a Mayor-Council form of government. Both the Mayor and four Councilmen are elected at large, directly by the people [2]. Primary civil services are provided by 108 full-time policemen (2.9 per 1000 residents), which is higher than the national norm of 2.1 per 1000 residents; and 51 full-time firemen (1.4 per 1000 residents) which is lower than the 1.6 national norm for 1000 residents. Medical services are supported by one hospital (118 beds), 35 doctors (0.9 per 1000 residents) and 19 dentists [7]. The doctor to resident ratio is lower than the U.S. average of 1.7 per 1000 residents. A new medical center with 145 beds and a professional staff will soon be in service [1,7].

The municipal water supply is drawn from the Animas and San Juan Rivers by way of Farmington Lake. Maximum capacity is 24 MGD, while the current peak load is 9.1 MGD. The storage capacity of all groundwater is 13.25 MGD [1]. Sanitary sewers handle 85 percent of the wastewater. A secondary treatment plant has a capacity to serve 50,000 people. Its present load is 3.5 MGD. Solid waste is disposed in a sanitary landfill [1,2,7].

Electricity is supplied to the Farmington region by the Navajo Dam, operated by the New Mexico Public Services Company. This facility is currently supplying 50 x 10⁶ kwh with an additional 1.75 GW capacity under construction. New Mexico uses only 40 percent of the electricity generated within its borders and is a net exporter of electrical energy [9].

In 1977, Farmington had a municipal elementary and high school enrollment of 7,155 students. These students represent 19 percent of the 1977 municipal population [7].

Cultural opportunities in the city include a civic auditorium and exhibition hall, an amateur theater, and six movie theaters. Farmington has one library containing 40,234 volumes [1].

For recreation, there are 13 parks, seven baseball fields, two golf courses, 7 tennis courts, two swimming pools, two skating rinks, two bowling alleys and an auto racing track available to Farmington residents.

A daily newspaper, six radio stations and one TV station operate in Farmington. There are also four cable TV companies [1,7]. The city is served by one airline, a rail system truck lines and one bus line. Traffic congestion is a substantial problem in Farmington [1].

In 1970, housing in Farmington was in short supply. The municipal area had 6,874 housing units. The median number of rooms per unit was 5.0 and the average number of occupants was 3.2. There were 59 units for sale and 311 available for rent [10].

ENVIRONMENT

Situated on a rolling plateau and mesas, Farmington derives visual appeal from its vast stretches of warm dry soils covered with sprawling steppe vegetation. The area is contrasted by luxurious, green irrigated farmland and by the deep blue waters of the San Juan, Animas, and La Plata Rivers [7,14].

The climate is moderate and dry, with an annual precipitation of 8.13 in and an average 35 percent relative humidity. The mean annual temperature is 51.7°F [1,7,11].

Natural resources in the area are low sulfur coal, uranium, and oil and gas [1,4,7]. Deer, bear and elk roam the lands. The nearby Navajo Reservoir is regularly stocked with trout, salmon, and bass [7]. The Colorado squawfish, inhabiting the San Juan River, and the peregrine falcon are nationally endangered animals known to be living within the 30 mile radius of Farmington [22].

Farmington's average daily water use is about 9.1 MGD and primary sources are the Animas and San Juan Rivers. The most common water pollutants are sediments and occasionally mercury. The water is treated with sand filtration and chlorination [1,7,26].

Farmington has poor air quality because of two power plants in the area which emit particulates and SO₂. In areas of the city, Federal Standards for CO (which has a primary value for 8 hours of 10 µg/m³) are violated and the air quality problem is not expected to be solved until 1982 [12,26].

CASE #8 SCENARIO: Farmington, New Mexico/High Btu Coal Gasification

The Farmington example assumes a high Btu coal gasification plant will occupy a 400 acre site 8 miles to the WSW, near the Navajo Indian Reservation. The site is adjacent to an existing sub-bituminous coal strip mine which allows the feedstock to be supplied by conveyor belt. Electricity not generated on site will be supplied by a 3 mile extension of the main power line and water will be pumped from the San Juan River through a new 2.5 mile pipeline. A new 5 mile road will lead North to U.S. Route 550, which leads to Farmington.

The population of Farmington was 38,000 in 1977, an increase of 42% from 1970. Fossil energy production is a prominent feature of the region's economy, with coal mines and oil and gas wells located throughout San Juan County.

The gasification plant would use the Synthane process and produce 250 million standard cubic feet per day of substitute natural gas, having a heating value near 950 Btu/scf. Construction would begin in 2 years and start-up will occur 4 years later. A total of 890 people will be employed at the plant, and the jobs of 330 miners at the adjacent strip mine will be continued during the 25 years of operation. Solid wastes from the plant could be disposed in the mines prior to reclamation. One of the several natural gas pipelines in San Juan County might be used to transport the main product to consumers.

TABLE OF RESULTS
Case #8: FARMINGTON, NM/High Btu Gasification

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	26.4	0.17	1.0	0.170	6.12	Percent 24-Hr SO ₂ Standard	17.4	0.19	0.17	0.032
1.7	Change in Unemployment	-33.3	-1.00	0.50	-0.500	CATEGORY 6 TOTAL			1.40	1.0	0.281
CATEGORY 1 TOTAL			0.17	1.0	0.170	7.1	% Assimilation Capacity Remaining	98.7	0	1.0	0
2.2	Percent Increase in Policemen	24.7	0.38	0.10	0.038	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Firemen	27.6	0.45	0.09	0.041	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	30.2	0.20	0.12	0.024	8.1	% Habitat Area Disturbed	0.25	0.01	0.50	0.005
2.8	Percent Increase in Hospital Beds	39.8	0.99	0.10	0.099	8.2	Endangered Aquatic Species	3.3	0.20	0.50	0.100
2.10	Percent Increase in Dentists	32.6	0.51	0.12	0.061			--	--	--	--
2.12	Percent Increase in Teachers	28.2	0.40	0.08	0.032			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	22.3	0.12	0.10	0.012			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	97.5	1.00	0.10	0.100	CATEGORY 8 TOTAL			0.21	1.0	0.105
2.15	% Marginal Solid Waste Area Used	18.6	0.09	0.12	0.011	9.1	% Reduction in Panoramic View	2.1	0.02	0.50	0.010
2.16	% Increase in Park & Recreation Area	19.2	0.16	0.07	0.011	9.2	Historical & Archeological Sites	B	0.20	0.50	0.100
CATEGORY 2 TOTAL			4.30	1.0	0.429	CATEGORY 9 TOTAL			0.22	1.0	0.110
3.13	Percent Bonding Capacity Required	278	1.00	1.0	1.00	10.7	Percent Change in Tax Rate	-15.1	-0.40	0.50	-0.200
CATEGORY 3 TOTAL			1.00	1.0	1.00	CATEGORY 10 TOTAL			-0.40	0.50	-0.200
4.2	Percent Increase in Mun. Housing	41.6	0.71	0.25	0.178	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	19.1	0.10	0.50	0.050						
4.11	% Underdeveloped Regional Land	0.3	0	0.25	0	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
CATEGORY 4 TOTAL			0.81	1.0	0.228	1	Employment/Population	0.12	0.019	0.020	
5.4	% Change in Elec. Import/Export	1.6	0.01	0.35	0.004	2	Community Services	0.10	0.048	0.043	
5.6	% Available Surface Water Required	6.4	0.13	0.65	0.085	3	Infrastructure	0.11	0.111	0.110	
CATEGORY 5 TOTAL			0.14	1.0	0.089	4	Land Use/Housing	0.11	0.030	0.025	
6.8	% Annual Particulate Standard	18.9	0.20	0.17	0.034	5	Utilities	0.08	0.008	0.007	
6.9	% Annual SO ₂ Standard	23.4	0.28	0.17	0.048	6	Air Quality	0.18	0.031	0.051	
6.10	% NO _x Concentration Margin	23.0	0.28	0.32	0.090	7	Water Quality	0.15	0	0	
6.11	% 24-Hr Particulate Standard	32.9	0.45	0.17	0.077	8	Endangered Wildlife	0.08	0.012	0.008	
						9	Aesthetics and Sites	0.07	0.012	0.008	
						10	Community Tax Revenue	(0.50)	(-0.200)	(-0.200)	
						SUM OF ADVERSE IMPACTS			1.00	0.271	0.272

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS

CASE #8: Farmington, NM/High Btu Coal Gasification

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.272 and 0.27T, respectively, indicating a moderate overall impact.
- The largest impacted category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- A substantial reduction in unemployment and significant reduction in the overall tax rate are expected.
- The Site & Process Scores are very close to the averages for the nine illustrative cases.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity required is almost triple the available portion of the legal limit.
- Community Services: The marginal capacity of the existing wastewater treatment facilities would be used and the number of hospital beds would have to be increased by about 40%.
- Land Use & Housing: A 42% increase in municipal housing units is predicted.
- Air Quality: Moderate impacts are predicted by all five ratio equations.

BENEFICIAL IMPACTS

- Employment and Population: Unemployment would be cut by about one-third.
- Community Tax Revenue: The overall tax rate would decline about 15%.

EFFECT OF VARIABLE WEIGHTING

- No significant difference is produced by the two weighting systems.

AMELIORATING ACTIONS

- Industrial and/or governmental funding to expand the municipal infrastructure would be desirable.
- Undertake expansion construction of new wastewater treatment plant and hospital.
- Develop more efficient control of air effluents.

IMPACTS REQUIRING MORE ANALYSIS

- All socioeconomic impacts.
- Air Quality modeling.
- Effect of development on the Colorado Squawfish (a rare aquatic species).

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23. Year-round vacant units. (See Reference 10.)
24. Persons per occupied unit, not necessarily year-round. (See Reference 10.)
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14. Gerlach, Arch C. *The National Atlas of the United States of America*, Washington D.C., United States Department of the Interior Geological Survey, 1970.
15. Topological Maps of Farmington from the United States Geological Survey, Washington D.C.
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CASE #9: RAWLINS, WYOMING

DEMOGRAPHICS

Rawlins is located in south central Wyoming, in Carbon County. Municipal population in 1975 was 9,592, an increase of 22 percent since 1970. The most recent estimates indicate a 33 percent growth from 1975 to 1977 to a current population of 12,800 [1,3,4]. Carbon County, with a 1975 population of 16,745, has experienced a similar growth pattern, which is largely attributed to the increase of energy-related activities. Population density ranges from 2.1 residents/sq mi in the most rural areas of Carbon County to 2,844 residents/sq mi within Rawlins. In 1970, only two percent of the population was nonwhite, 35 percent was under 18 and 10 percent over 65 years old [1,3,4].

LAND

Rawlins occupies a land area of 4.5 sq mi or 0.06 percent of the 7,905 sq mi of Carbon County. Carbon County's land is 57 percent undeveloped and 10.5 percent forest. A large portion of industrial land is devoted to energy extraction and refinement activities [1,3].

ECONOMICS

In 1977, the labor force was 7,278, of which 7,033 were employed and 245 unemployed (3.4% unemployment). Mining and the wholesale/retail business employ 44 percent of the labor force, with government and services being the least important employment sectors. Per capita income averaged \$5,000 per person in 1977, which was slightly less than the national average, which was \$4,834 in 1975 [1,3].

Financial services for Rawlins and Carbon County are provided by two banks and one savings and loan association [1].

The total revenue for Rawlins in 1977-1978 was \$3,201,280. Property tax accounted for 6.7 percent (100% assessed) of this revenue. The local mill rate is approximately 76 [15].

SOCIAL

The government of Rawlins consists of a Mayor and City Council. Primary civil services are provided by 15 full-time policemen (1.6 per 1000 residents) and five firemen (0.5 per 1000 residents). These figures are less than the national averages of 2.1 and 1.6 police and firemen per 1000 residents, respectively [1,2].

Medical services are provided by twelve doctors (1.3 per 1000 residents) which is less than the national average of 1.7 per 1000 residents, and five dentists (0.5 per 1000 residents). Carbon County supports a 100-bed hospital, three private clinics and a nursing home [1,2,9].

The municipal water supply comes primarily from the North Platte River. Treatment facilities have a capacity of 3.6 MGD, with 120 million gallons of storage capacity available to handle peak demands of 4.4 MGD [1,3].

In 1974, the electric generating capacity of Wyoming was 2.3 GW. About 50 percent or $10,803 \times 10^6$ kwh was generated. Only 40 percent of the amount generated was sold intrastate, which means the state is a net exporter of electrical energy [5,6].

In 1977, Rawlins had a municipal elementary and high school enrollment of approximately 2,273 students. These students represent 18 percent of the 1977 municipal population [19].

Culturally, the Rawlins area supports an art gallery Community Concert Association and Community Players. For recreation, there are theaters, golf and outdoor sports such as hunting and fishing [1,2,3].

Rawlins has one radio station and one newspaper. There is no local TV station, but eight-channel reception is available [1].

The Union Pacific Radioroad goes through Rawlins and three bus companies, including Trailways and Greyhound are in service. Trans Mountain Air, Dwight France Air Charter and Welton Flying Service provide aviation services [1,3].

In 1970, there were 2,772 housing units in the Rawlins metropolis, which results in 2.5 people per housing unit. There were 23 units for sale and 173 for rent [8].

ENVIRONMENT

Rawlins is surrounded on three sides by mountains, with desert on the fourth side. Rawlins, at an elevation of 6,755 ft above sea level, is distinguished by fertile valleys and semi-arid plateaus where oil, coal and uranium resources are abundant. Area wildlife includes antelope, bear, deer, elk, and various game birds [2]. Two endangered species on the federal list, the black-footed ferret, and the peregrine falcon, live within the 50 mi radius of Rawlins [11].

Climate exhibits seasonal variation around a mean annual temperature of 42.2°F. Precipitation averages 10-15 in/year and the average wind speed is 15 mph [1].

There are no major industries upstream of Rawlins and the drinking water, up to the present, has required only chlorination. Turbidity, due to farmland runoff, however, is creating the necessity for a more extensive water treatment facility to be built in the near future. Plans for the community's first sewage treatment plant are also underway [1,3,21].

Air quality in Rawlins is good. The suspended particulate geometric mean levels for 1976 reached a maximum of 84 g/m^3 and a second highest value of $50 \text{ } \mu\text{g/m}^3$, both of which are well below the National Primary Standard of $260 \text{ } \mu\text{g/m}^3$ and below the National Secondary of $150 \text{ } \mu\text{g/m}^3$ [10,20].

CASE #9 SCENARIO: Rawlins, Wyoming/Oil Shale Conversion

An oil shale conversion plant would be built in the Great Divide Basin, near the northwest corner of Carbon County. The site is located 34 mi west of Rawlins, Wyoming, the nearest town. The existing Union Pacific line which passes through Rawlins will be adapted for commuter rail service. A 1.5 mi spur will link the site with the railroad; the site will be connected to U.S. Route 30 by a new 3-mile road.

Rawlins, with a population of 12,800, is already an energy-based town. Coal and uranium mines and oil wells are scattered throughout Carbon County.

The oil shale plant would use the Paraho process and produce 50,000 barrels per day of raw shale oil. Construction is scheduled to begin in three years and will take four years to complete. The plant will employ 1100 people and consume 2.3 million gallons of water/day during its 25-year operating life. Shale will be mined underground in an adjacent ridge and residual spent shale will be disposed in a nearby valley. The plant will be located five miles WSW of the Utah Oil Refining Station which presents the potential for an agreement whereby the refinery might process the raw oil produced. Capacity of the refinery and its connecting pipeline might need to be increased.

TABLE OF RESULTS
Case #9: RAWLINS, WY/Oil Shale Liquefaction and Gasification

Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value	Equation Number	Equation Title	Ratio	RIC Impact Value	Impact Weight	Weighted RIC Impact Value
1.6	Community Population Increase	49.4	0.66	1.0	0.660	6.12	Percent 24-Hr SO ₂ Standard	5.1	0.05	0.17	0.009
1.7	Change in Unemployment	-33.3	-1.00	0.40	-0.400	CATEGORY 6 TOTAL			0.35	1.0	0.068
CATEGORY 1 TOTAL			0.66	1.0	0.660	7.1	% Assimilation Capacity Remaining	97.4	0	1.0	0
2.2	Percent Increase in Policemen	60.7	1.00	0.10	0.100	7.2	% Allowable Pollutant Load	0	0	0	0
2.4	Percent Increase in Fireman	466	1.00	0.09	0.090	CATEGORY 7 TOTAL			0	1.0	0
2.6	Percent Increase in Doctors	55.8	0.87	0.12	0.104	8.1	% Habitat Area Disturbed	0	0	0	0
2.8	Percent Increase in Hospital Beds	43.6	0.29	0.10	0.029	8.1	% Habitat Area Disturbed	1.0	0.03	1.0	0.03
2.10	Percent Increase in Dentists	57.9	0.88	0.12	0.106			--	--	--	--
2.12	Percent Increase in Teachers	42.6	0.96	0.08	0.077			--	--	--	--
2.13	% Water Supply Mar. Capacity Used	21.1	0.10	0.10	0.010			--	--	--	--
2.14	% Wastewater Mar. Capacity Used	∞	1.00	0.10	0.100	CATEGORY 8 TOTAL			0.03	1.0	0.03
2.15	% Marginal Solid Waste Area Used	8.1	0.03	0.12	0.004	9.1	% Reduction in Panoramic View	2.07	0.02	0.50	0.010
2.16	% Increase in Park & Recreation Area	162	0.71	0.07	0.050	9.2	Historical & Archeological Sites	C	0.40	0.50	0.200
CATEGORY 2 TOTAL			6.84	1.0	0.670	CATEGORY 9 TOTAL			0.42	1.0	0.210
3.13	Percent Bonding Capacity Required	933	1.00	1.0	1.000	10.7	Percent Change in Tax Rate	-69.3	-1.00	0.40	-0.400
CATEGORY 3 TOTAL			1.00	1.0	1.000	CATEGORY 10 TOTAL			-1.00	0.40	-0.400
4.2	Percent Increase in Mun. Housing	87	0.60	0.25	0.150	SITE AND PROCESS IMPACT SUMMARY () = Beneficial Impact					
4.10	% Underdeveloped Municipal Land	246	1.00	0.50	0.500	Cat. No.	Category Title	Weight	Equal Weight	Weighted	
4.11	% Underdeveloped Regional Land	0.07	0	0.25	0	1	Employment/Population	0.12	0.073	0.079	
CATEGORY 4 TOTAL			1.60	1.0	0.650	2	Community Services	0.10	0.076	0.067	
5.4	% Change in Elec. Import/Export	-12.5	-0.07	0.20	-0.014	3	Infrastructure	0.11	0.111	0.110	
5.6	% Available Surface Water Required	25.6	0.78	1.0	0.780	4	Land Use/Housing	0.11	0.059	0.072	
CATEGORY 5 TOTAL			0.78	1.0	0.780	5	Utilities	0.08	0.087	0.062	
6.8	% Annual Particulate Standard	5.2	0.05	0.17	0.009	6	Air Quality	0.18	0.008	0.012	
6.9	% Annual SO ₂ Standard	4.0	0.04	0.17	0.007	7	Water Quality	0.15	0	0	
6.10	% NO _x Concentration Margin	4.4	0.05	0.32	0.016	8	Endangered Wildlife	0.08	0.003	0.002	
6.11	% 24-Hr Particulate Standard	15.1	0.16	0.17	0.027	9	Aesthetics and Sites	0.07	0.023	0.015	
						10	Community Tax Revenue	(0.50)	(0.333)	(0.400)	
						SUM OF ADVERSE IMPACTS			1.00	0.440	0.419

ANALYSIS SUMMARY

SOCIOECONOMIC AND ENVIRONMENTAL IMPACTS CASE #9: Rawlins, WY/Oil Shale Conversion

SUMMARY

- The variably and uniformly weighted Site & Process Scores are 0.431 and 0.451 respectively, indicating a major overall impact.
- The largest contributing category is Infrastructure with a score of 1.0 (prior to the application of category weights).
- Substantial declines in county unemployment and the municipal tax rate can be anticipated.
- The Site & Process Scores are the second highest obtained in the nine illustrative cases.

MAJOR ADVERSE IMPACTS

- Infrastructure: The bonding capacity required is an order of magnitude above the available portion of the legal limit.
- Community Services: Large impacts can be expected for every element except hospital beds, water supply and solid waste.
- Utilities: About one quarter of the available surface water would be consumed.
- Employment and Population: The town would be subjected to a 50% population increase.
- Land Use & Housing: Municipal land requirements are projected to be 2.5 times the amount of underdeveloped land.

BENEFICIAL IMPACTS

- Employment and Population: Unemployment in the county would be cut by one-third, but this represents only 82 jobs.
- Community Tax Revenue: The municipal tax rate could be reduced by almost 70%.
- State exports of electrical energy would be increased by 1/8 due to the excess generating capacity of the conversion plant.

EFFECT OF VARIABLE WEIGHTING

- The variably weighted Site & Process Score is about 5% less than the uniformly weighted score.

AMELIORATING ACTIONS

- Recovering oil from the shale by an in situ or modified in situ process would create smaller socioeconomic impacts since the labor force required would be smaller.
- New communities could be started in the area.
- Industrial and/or governmental funding to expand the municipal infrastructure and finance housing construction is needed.
- The acquisition of additional water rights or the development of groundwater resources would alleviate potential water shortages.

IMPACTS REQUIRING MORE ANALYSIS

- The alternative proposed in this scenario may be rejected based on this preliminary analysis.
- The largest uncertainties in this example are in the Employment and Population, Community Services, Land Use & Housing and Utilities categories.

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15. Telephone Communication with Harriet Carlson, Rawlins, Wyoming, Rawlins City Treasurer, Chief Clerk's Office, May 4, 1978.
16. CEM estimate, using rental and homeowner vacancy rates for year-round units. (See Reference 8.)

References for Case #9 (continued)

17. Year-round vacant units only. (See Reference 8.)
18. Persons per occupied unit, not necessarily year-round. (See Reference 8.)
19. CEM estimate, obtained by using overall student:teacher ratio. (See Reference 1.)
20. Telephone Communication with Mr. Collins, Air Quality Division, Department of Environmental Quality, Cheyenne, Wyoming, March 30, 1978.
21. Telephone Communication with Bob Pinther, Wyoming Department of Environmental Quality, Water Quality Division, March 31, 1978.
22. Lerner, William. *Statistical Abstract of the United States 1976*, Washington, D.C., U.S. Department of Commerce, Bureau of the Census, 97th Edition, July 1976.
23. CEM estimates.
24. Telephone Communication with Lamar Jacobsen, City Building Inspector, Rawlins, Wyoming, June 6, 1978.

GLOSSARY

A

absolute zero: The lowest possible temperature, characterized by the complete absence of heat and equivalent to approximately -273.16°C or -459.69°F .

absorbent: The liquid used to separate gases in absorption.

absorption: A process in which two or more gases are separated by dissolution of one gas into a liquid which cannot dissolve the other gases.

acid gas: A gas with a high concentration of H_2S , produced by reversal of the absorption process.

acid mine water: Water with a pH of less than 6.0 discharged from active or abandoned mines and from areas affected by mining operations.

adsorption: The physical and chemical adherence of a gas to the surface of a solid.

alcohols: Hydrocarbon compounds containing the hydroxyl (OH) group.

aldehydes: Any of various organic compounds containing a carbonyl group (CO) at the end of a hydrocarbon chain.

alluvium: The detrital materials eroded, transported, and deposited by streams; an important constituent of shelf deposits. Also known as alluvial deposit.

ambient: A term referring to conditions in the vicinity of a reference point, usually related to the physical environment external to the reference point.

ancillary energy: A measure of the external energy required for an energy process. It includes such things as energy for process heat and electricity for pumps, compressors and lighting.

anhydrous ammonia: Liquid ammonia, a colorless liquid boiling at -33.3°C .

anthracite: Hard coal containing 86 to 98 percent fixed carbon and small percentages of volatile material and ash (see rank).

API gravity (*API): A measure of the mass of a fluid relative to water; it is inversely proportional to viscosity.

aqueous: Made from, with, or by water; for example, an aqueous solution is one in which water is the solvent.

aquifer: A water-bearing bed or stratum of rock, sand or gravel.

aromatic hydrocarbons: A group of stable hydrocarbon compounds containing one or more six carbon rings.

ash: The residue left when combustible material is thoroughly burned or otherwise oxidized.

Athabasca: A region in Northeastern Alberta, Canada, containing large quantities of tar sands deposits.

auxiliary energy: See ancillary energy.

B

baghouse: A device containing a fabric filter used to separate particulates from an air stream.

barrel: A unit of weight or volume whose magnitude varies according to the particular commodity for which it is employed. (Petroleum barrel = 42 gallons)

base load: The portion of a power plant load that is practically constant for long periods of time.

bench scale: See conversion plants.

benzene: An aromatic liquid hydrocarbon, C_6H_6 , used as a solvent and as a motor fuel. It is colorless volatile, flammable and toxic.

bitumen: A general name for various solid and semi-solid hydrocarbons particularly those found in tar sands.

Bituminous coal: An intermediate rank coal with low to high fixed carbon, intermediate to high heat content, a high percentage of volatile matter, and a low percentage of moisture (see rank).

blow-down: The removal of water from a cooling system; it is done to control the concentration of solids, which accumulate when the water evaporates.

boiler: A vessel in which water is vaporized by the application of heat.

borehole: A hole made by drilling into the earth's surface.

bottoming turbine: A conventional steam turbine used in MHD to extract energy from the combustion products after they have passed through the MHD channel.

BTU (British Thermal Unit): The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit, from 39.2 to 40.2 degrees Fahrenheit.

burner: A device for controlled combustion of fuel and air.

by-product: A material obtained in addition to the principal or primary material in a manufacturing process.

C

caking: The softening and agglomeration of coal as a result of the application of heat.

carbonates: Compounds or ions containing the CO_3^{2-} group.

carbon monoxide: A colorless, odorless, very toxic gas, CO, that is formed as a product of the incomplete combustion of carbon.

carcinogen: A substance or agent producing or inciting cancer.

carbonization: Destructive heating of carbonaceous substances with the production of a solid, porous residue, or coke, and the evolution of a number of volatile products. For coal, there are two principal classes of carbonization, high-temperature coking (about 900°C) and low-temperature carbonization (about 700°C).

catalyst: A substance that accelerates the rate of a chemical reaction without itself undergoing a permanent chemical change.

centrifuge: An apparatus rotating at high speed to separate solids from liquids or to separate substances of different densities.

ceramic: Made from nonmetallic minerals by firing at high temperatures.

char: A mixture of ash and carbon which remains after partial combustion or heating of coal.

Claus process: A process that takes gas streams containing 10 percent or more hydrogen sulfide (H_2S) and produces elemental sulfur of high purity.

climax community: A persistent terminal ecosystem; as opposed to a transient ecosystem.

closed cycle: A thermodynamic power cycle in which the working fluid is recycled.

coal: A natural solid material consisting of amorphous elemental carbon with various amounts of organic and inorganic compounds.

coal rank: See rank.

coke: Strong porous residue consisting of carbon and mineral ash formed when bituminous coal is heated in a limited air supply or in the absence of air. Coke may also be formed by thermal decomposition of petroleum residues.

combined cycle gasification: Gasification processes which use a gas turbine to extract energy from the hot gaseous products.

combined cycle MHD: A system in which a conventional power plant is integrated with MHD power generation.

combustion air: Air supplied for the burning of a fuel.

combustion gas: Gas formed by the burning of a fuel.

combustion products: The gases, vapors, and solids resulting from the combustion of fuels.

compressor: A machine which pressurizes air or other gases.

condensate: Water produced by removing heat from (condensing) steam.

condenser: An apparatus for cooling vapors to liquids.

consumption: The utilization of economic goods in the satisfaction of wants or in the process of production resulting chiefly in their destruction, deterioration, or transformation.

conversion: A change in one form of energy to other forms (e.g. heat to electricity). The overall amount of energy is never changed.

conversion plants:

- Bench scale: A small laboratory model of a process used to perform preliminary tests. It usually handles less than 0.5 ton of feedstocks per day.
- Process development unit: A small scale facility, usually producing 0.5 to 10 tons/day; basic chemical, physical and engineering data needed to evaluate the process and design a larger unit are obtained by the operation of a pdu.
- Pilot plant: A small scale, often 10 to 1000 tons/day facility operated to verify or refute the expectations of the developers prior to the investment of large amounts of capital and to obtain data needed in the design of larger scale plants.
- Demonstration plant: A facility often handling 1000 to 10,000 tons/day which is operated to prove the viability of the technology, establish economic and environmental factors and encourage the creation of a viable industry using the technology.
- Commercial scale plant: A facility of sufficient size, usually 10,000 tons/day or more for fossil energy conversion technologies, such that a favorable economic development (i.e. profit) will result from its operation.

cooling tower: A structure in which the temperature of circulated water used as a coolant is reduced by partial evaporation.

corrosion: A chemical process causing gradual disintegration or decomposition.

cracking: The process of breaking large molecules in a refinery feedstock into smaller molecules with a higher energy content.

crude gas: Impure gas produced in a gasifier.

cyclone separator: A cleaning device which uses a circular flow to separate heavier particulates from stack gases.

D

debt service: The amount of interest due annually on a long term debt.

deciduous: Falling off or being shed at the end of the growing period or season.

degasification: A process for removing naturally occurring methane from coal seams.

degree day: A unit used to express the variation of the mean daily temperature from a reference point, usually 65°F during the heating season and 75°F during the cooling season.

demand: The quantity of a commodity or service wanted at a specified price and time; willingness and ability to purchase a commodity or service.

demographics: The characteristics of human populations, especially with reference to size, density, growth, distribution and migration.

demonstration plant: See conversion plants.

depletion: A yearly allocation of the estimated value of a limited resource, as extracted from a non-replaceable supply, allocated over the estimated total of useful resources.

depolymerization: The change of a large molecule into simpler molecules usually accompanied by the substitution of hydrogen for oxygen in the molecular structure.

desulfurization: The removal of sulfur from combustion products or other gases by chemical reactions or absorption.

devolatilization: The removal of a portion of the volatile matter from medium-and high-volatile coals.

diluent: A substance added to a mixture or solution to make one or more of the components less concentrated.

discounted cash flow: Current value of cash flow(s) as obtained by discounting (using compound interest to determine sums earlier in time which are equivalent to a later, larger sum).

distillation: A technology separating two or more fluids based on differences between their boiling temperatures.

dolomite: A mineral, $\text{CaMg}(\text{CO}_3)_2$, found as a crystal and in extensive beds as a compact limestone.

E

ebullated-bed: See fluidized bed.

economic life: The period of commercial use of a product or facility. It may be limited by obsolescence, physical life of equipment, or changing economic conditions.

economizer: A heat exchanger for recovering heat from flue gases and using it to heat feedwater or combustion air.

efficiency: A ratio of the useful energy delivered by a dynamic system to the energy supplied to it.

effluent: Waste material discharged into the environment especially as a pollutant.

electrode: A conductor used to establish electrical contact with a non-metallic part of a circuit.

electromagnet: A core of magnetic material surrounded by a coil of wire through which an electric current is passed to magnetize the core.

electrostatic precipitator: A device for removing suspended particles from a gas by charging the particles and attracting them to an oppositely charged electrode.

emissions: Substances discharged into the air or water.

endothermic: A process in which heat is absorbed.

energy: The capacity for doing work.

energy consumption: The act of using up useful forms of energy.

energy content: The amount of heat released by combustion.

entrained bed: A coal combustion (or gasification process) in which pulverized coal is suspended in a gas stream.

equilibrium: A condition in which contending forces are balanced or equalized independent of time.

equimolar: Of or relating to an equal number of moles (see mole).

equity: The net worth of a firm or corporation (total assets less total debts).

evaporation pond: A man-made body of water in which water is separated from dissolved materials by vaporization. The ponds are often lined to prevent contamination of groundwater.

exothermic: A chemical reaction that gives off heat.

exponential: Expressible or approximately expressible as an exponential equation (involving an exponential function of a variable).

extraction: A process for separating certain constituents of a mixture by contacting the mixture with a liquid which dissolves selected components only.

F

fauna: Animals or animal life.

feedstock: A raw material supplied to a processing plant.

filtration: The separation of solids from liquids by passing the mixture through a suitable medium, which is called a filter.

finer: Small particles of material which pass through a standard screen on which coarser fragments are retained.

fixed bed: A type of vessel in which the feedstocks are supported by or pass through a stationary structure.

fixed carbon: The solid, non-volatile, combustible portion of coal.

flame front: The leading edge of an advancing zone of combustion.

flaring: The practice of burning, in open air, by-product gases which cannot be economically used.

flora: Plant life.

flowsheet: A diagrammatic representation of a process, showing the sequence and interdependence of the stages.

flue gas: Gases which result from combustion processes, primarily water vapor, and carbon dioxide, though carbon monoxide and trace gases are usually present as well.

fluid: A general term which encompasses both liquids and gases.

fluidized bed: A body of finely crushed particles suspended by a gas blown through them. The gas separates the particles so that the mixture behaves like a turbulent liquid.

fossil fuel: Carbonaceous materials with a high energy content formed from the remains of vegetation several million years ago.

fractionation: A distillation process for the separation of various components of liquid mixtures; an effective separation can only be achieved by the use of fractionating columns attached to the still.

froth-floatation: A separation process that uses the surface wetting behavior of chemicals to precipitate some materials and float others in an aerated pond or vessel.

G

gasification: Conversion of a solid fuel into a gaseous form by any of a variety of chemical processes.

gasifier: A vessel in which gasification occurs.

generic: Relating to a characteristic of a whole group or class.

gradient: A change in the value of a quantity corresponding change in a given variable.

Gross National Product (GNP): The total value of the goods and services produced in a nation during a specified period.

gypsum: A widely distributed mineral consisting of hydrous calcium sulfate, $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$, used in some building materials.

H

heating value: See energy content.

high Btu gas: A gas having a heating value of 700 to 1,040 Btu per standard cubic foot, which approaches the value for natural gas.

Higher Heating Value (HHV): The heat liberated during a combustion process in which the product water vapor is condensed to a liquid.

Holism: The theory that determining factors must be viewed as wholes rather than the sum of individual parts.

hydrated: Containing water in a combined form.

hydrocarbons: Organic compounds containing only carbon and hydrogen, characteristically occurring in petroleum, natural gas, coal, and bitumens.

hydrocoking: Coking of tars, SRC, etc., under hydrogenating conditions to form liquid products.

hydrocracking: The combination of cracking and hydrogenation of organic compounds.

hydrogasification: Gasification that involves the direct reaction of fuels with hydrogen to optimize formation of methane.

hydrogenation: A chemical reaction involving the addition of gaseous hydrogen to a substance in the presence of a catalyst under high temperatures and pressures.

Hydrogen Donor Solvent: A solvent, such as anthracene oil, tetralin, decalin, etc., which transfers hydrogen to coal constituents, producing liquid products. The donor solvent is rehydrogenated and returned to the reactor.

hydrotreating: Using a catalyst, high temperature, and high pressure to change the structure of a molecule through the addition of hydrogen. An additional benefit may be the removal of sulfur as hydrogen sulfide in the process.

I

impact: A change produced on a given variable such as the site descriptors in Table 6-3.

infrastructure: The underlying foundation or basic framework (as of a system or organization).

injection well: A term referring to a well through which air and/or other substances are supplied during in situ conversions.

In situ: In the natural or original position; applied to energy resources when they are processed in the location where they were originally deposited.

Intermediate BTU GAS (IBG): Synthesis gas product with an HHV between 300 and 700 BTU per standard cubic foot, consisting mainly of carbon monoxide and hydrogen.

inverter: A device for converting direct current into alternating current.

ion: An atom or group of atoms, which has a net electric charge.

ionization: The breaking up of a molecule into 2 or more charged components (ions).

K

kerogen: A solid, largely insoluble organic material occurring in oil shale which yields oil when it is heated in the absence of oxygen.

kiln: An oven, furnace, or heated enclosure used for processing a substance by burning, firing or drying.

kinetic energy: The energy that an object possesses because it is moving; it is determined by the mass and the speed of the object.

L

lacustrine: Of, relating to, or formed in lakes.

leaching: The continued removal, by water, of soluble matter from rock or soil.

lignite: The lowest-rank coal, with low heat content and fixed carbon, and high percentages of volatile matter and moisture; an early stage in the formation of coal (see rank).

lime: Hydrated calcium oxide, Ca(OH)_2 , a material used in building, agriculture, metallurgy and chemical industries, and in the treatment of water, sewage and wastes.

limestone: A sedimentary rock composed mostly of calcium carbonate (CaCO_3) and possibly some magnesium carbonate (Mg CO_3).

liquefaction: Conversion of a solid to a liquid; with coal this invariably involves hydrogenation to break down the large coal molecules to simpler molecules.

Liquified Natural Gas: A clean, flammable liquid existing under very cold conditions, that is almost pure methane.

lock hopper: A mechanical device that permits the introduction of a solid into an environment of different pressure.

loess: An essentially unconsolidated, unstratified calcareous silt; commonly it is homogeneous, permeable, and buff to gray in color, and contains calcareous concretions and fossils.

low Btu gas: A gas having a heating value of 100 to 300 Btu per standard cubic foot.

M

Mach number: The ratio of the speed of an object to the speed of sound in the undisturbed medium in which the object is traveling.

mahogany zone: An approximately 100 foot thick deposit of high yield oil shale in the Green River Formation (Wyoming, Colorado and Utah), resulting from bottom deposits of algae approximately 50 million years ago.

Megawatt electrical (MW_e): One million watts of electrical energy; MW_e is used to express the output capacity of a power plant.

Megawatt thermal (MW_t): One million watts of thermal (heat) energy; MW_t is used to express the amount of energy which is fed to a power plant.

methanation: A reaction in which carbon monoxide and hydrogen are converted to methane.

methane: A colorless, odorless, flammable gaseous hydrocarbon, CH_4 , that is a product of decomposition of organic matter in marshes or mines or of the carbonization of coal. It is used as a fuel and as a raw material in chemical synthesis.

micron: A unit of length equal to one millionth of a meter.

mill: A money of account equal to 1/10 cent ($\frac{1}{1000}$ dollar).

mine mouth: The vicinity or area of a mine, usually within a few miles.

methanation: The catalyzed reaction of CO and H₂ to form CH₄ and H₂O.

modified in situ: An oil shale retorting process in which a fraction (15 to 20%) of the shale is mined, the remainder is fractionated by explosives, and a retort is initiated in the rubbleized shale.

mole: A quantity of particles equal to the number of atoms in 12 grams of the pure carbon isotope carbon-12 (6.023×10^{23} atoms).

molecular weight: The weight of one mole of a substance; that is, the weight in grams of 6.023×10^{23} molecules of the substance.

moving-bed: Particled solids in a process that are circulated either mechanically or by gravity flow.

N

naphtha: Any of various volatile, often flammable liquid hydrocarbon mixtures used chiefly as solvents and diluents.

Nitrogen oxides (NO_x): Compounds formed by the reaction of nitrogen and oxygen in air, which occurs only at high temperatures. NO_x is used to refer to both common oxides, NO and NO₂.

nuclear: Of, relating to, or using atomic energy.

O

octane members: Compounds which are resistant to premature detonation in an internal combustion engine.

off-gas: A gas produced during the hydrotreating of liquids in a refinery or during the upgrading of oil produced from shale or tar sands.

oil shale: Sedimentary rocks containing insoluble organic matter (kerogen) which can be converted into oil by heating.

OPEC: Organization of Petroleum Exporting Countries.

Open Cycle: A thermodynamic power cycle in which the working fluid passes through the system only once and is then exhausted to the atmosphere.

overburden: The rock, soil, etc., covering a mineral to be mined.

oxidant: A substance, most commonly oxygen, which reacts with another substance by removing one or more of its electrons.

oxidation: The process of chemical reaction with oxygen.

ozone: A molecule made of three oxygen atoms that is a bluish, irritating gas of pungent odor, is formed naturally in the upper atmosphere by a photochemical reaction with solar ultraviolet radiation; a major agent in the formation of smog.

P

paleontology: A science dealing with the life of past geological periods as known from fossil remains.

paraffins: A class of waxy solid compounds found in petroleum and shale oil.

particulates: Minute solid particles which tend to remain individually dispersed in stack emissions and the atmosphere.

peak construction: The point at which the labor force involved in the construction of a facility, highway, etc. reaches its maximum number.

peak load: The maximum demand for electrical energy which occurs over a short period of time.

permeability: The ability of a porous medium to conduct fluid through it.

petrochemical: Chemicals derived from crude oil or natural gas, or their coal-derived substitutes; they include light hydrocarbons such as butylene, ethylene, and propylene—the raw materials for the production of plastics.

pH: A measure of the acidity or alkalinity of a fluid; a low pH (less than 7) indicates acidity, and a high pH (greater than 7) indicates alkalinity.

phenols: Any of various organic compounds containing one or more hydroxyl (OH) groups attached to an aromatic group.

physical life: The estimated period over which a plant or piece of equipment could be operated, until shut down is forced by physical deterioration.

pilot plant: See conversion plants.

plant: A facility designed to convert raw materials into a saleable product; for example, coal to gas or oil to electricity.

plume: A mobile column or band of exhaust gases or water vapor emitted from a smokestack, chimney or cooling tower.

pour point: The lowest temperature at which an oil will flow under standard conditions.

primary employment: Jobs created directly by a specific development, such as the construction and operation of a synthetic fuels plant.

process: A specified method for carrying out a given technology.

Process Development Unit (PDU): See conversion plant.

pretreatment: Partial oxidation of the outer surface of coal particles; done to keep the particles from agglomerating (sticking together).

primary energy source: A form of energy such as coal, gas, etc. which can be used to supply other forms of energy, (e.g. heat, electricity).

process heat (energy): See ancillary energy.

pulverization: The reduction of a substance to a powder.

pyrolysis: Thermal decomposition of organic compounds in the absence of oxygen.

Q

Quad: 10¹⁵ (1 quadrillion) Btu's

quenching: Cooling by immersion in an oil or water bath or spray.

R

radiant: Transferring heat by radiation.

rank: A classification of coal according to percentage of fixed carbon and heat content. High rank coal is presumed to have undergone more geological and chemical change than lower rank coal.

reaction: Any chemical change, or the transformation of one or more molecules (reactants) into other kinds of molecules (products).

reactor: A vessel in which one or more reactions take place under controlled conditions.

reciprocating engine: An engine in which to-and-fro motion of a piston is transformed into circular motion of the crankshaft.

reclamation: To restore land used for mining, etc. to a desired state, usually one approximating its previous condition.

refinery: A building or apparatus used for refining purposes. To refine means to free from impurities.

reforming: The alteration of the molecular structure of organic molecules, usually occurring at a elevated temperature and pressure.

regenerative: Capable of being restored to its original form; said of processes in which a feedstock is recovered, regenerated and recycled.

reserve: Resources which are known in location, quantity, and quality and which are economically recoverable using currently available technologies.

residual: That which remains or is left.

resource: Deposits which are known or speculated to exist, including those which are not economically recoverable at present.

retort: (n.) A closed heating facility used to process oil shale.
(v.) To decompose by heat.

retort gases: Gases released by the decomposition of large organic molecules during retorting.

retrofit: To furnish with new parts or equipment, often replacing existing ones. Coal oil slurry is a retrofit technology since existing oil-fired burners are replaced by burners which can handle the slurry. Slurry preparation and handling equipment must also be furnished.

revegetation: The establishment of a new vegetative cover on land where the previous vegetation was stripped.

rubblize: To fragment into small pieces by the use of explosives.

run-off: The portion of precipitation on the land that ultimately reaches streams.

S

saline water: Water containing salt.

salinity: A comparative indication of the concentration of salts in natural waters.

salt: A group of substances that result from the reaction between acids and bases; a compound of a metal (positive ion) and a non metallic negative ion.

sandstone: A sedimentary rock, which consists of coherent grains of sand.

scrubber: Equipment used to remove pollutants, such as sulfur oxides or particulate matter, from stack gases.

seam: A bed of coal or other valuable mineral of any thickness.

seam dip: The angle between the orientation of a coal seam and a horizontal plane.

secondary employment: Jobs created in supplying services to an industry or business and its employees.

sedimentary rock: Rock formed of mechanical chemical or organic sediment.

seed regeneration: In MHD, the separation of reacted seed material from slag and subsequent chemical reactions which restore the material to its original chemical composition.

separator: A device or machine for separating materials.

settling pond: A body of water used as a separator in which suspended material sinks to the bottom and water is recovered from the surface.

shift reaction: A step in the process of converting coal to methane (CH_4); during this step the ratio of H_2 to CO is altered from 2:1 to 3:1 by a catalytic reaction with steam.

SIC: Standard Industrial Classification; a classification of establishments by type of activity in which engaged. Prepared and used by the U.S. Department of Commerce.

slag: Molten or solidified ash.

sludge: The material recovered when sulfur oxides are removed from flue gas.

slurry: A suspension of a pulverized solid in a liquid. Slurries of oil and coal or water and coal are used in coal processing and transportation.

SMSA (Standard Metropolitan Statistical Area): Area designations by the U.S. Office of Management and Budget. The general concept of an SMSA is to define an integrated economic and social unit with a large population nucleus for statistical reporting.

solute: A substance that mixes with or dissolves in a solvent to produce a solution.

solution: The mixing of a solid, liquid, or gaseous substance with a liquid, forming a homogeneous mixture from which the dissolved substance can be recovered by crystallization or other physical processes. It is generally not accompanied by chemical change, and is thus strictly a physical phenomenon that may or may not involve ionization.

Solvent Refined Coal (SRC): A coal extract derived by solvent extraction of ash and some sulfur compounds.

sour water: Effluent water containing large amounts of sulfur or sulfur compounds.

T

spent sand: The residual left after bitumen is extracted from tar sands.

stack gas: Gases resulting from combustion which are released to the atmosphere.

Stage: A step in a sequence of reactions in the conversion of a fossil fuel. Each stage occurs in a different location, often at different temperatures and pressures and in the presence or absence of a catalyst and/or air.

standard cubic foot (scf): A volume of a gas at a standard conditions of temperature and pressure, usually 60°F and 1 atmosphere.

start-up: The initial period of operating a facility, during which interruptions in service are most common.

stoichiometry: The definite proportions in which molecules react chemically to form new molecules.

stream: An unbroken flow of a gas or liquid.

strip mine: A mine that is worked by stripping (removal of overburden); a coal mine situated along the outcrop of a flat dipping bed.

stripping: The removal of the more volatile components from a liquid mixture of compounds.

sub-bituminous: A low rank coal with low fixed carbon and high percentages of volatile matter and moisture. (see rank).

subsidence: The sinking, descending or lowering of the land surface.

Substitute or Synthetic Natural Gas (SNG): A synthetic gas conforming to natural gas standards (see High Btu gas).

sulfates: Compounds or ions containing the group SO_4^{4-} .

sulfur dioxide (SO_2): One of several forms of sulfur in the air; an air pollutant generated principally from combustion of fuels that contain sulfur. A natural source of sulfur dioxide is volcanic gases.

superconducting magnet: An electromagnet operating at a temperature near absolute zero; at extremely low temperatures very little power is needed to create a magnetic field.

superheat: To heat steam above its boiling temperature; such steam is said to be superheated.

syncrude: A liquid obtained by processing oil shale coal or tar sands.

synthetic fuels: A fuel similar to a naturally occurring fossil fuel but derived from another fossil fuel; for example, oil derived from coal.

synthesis gas: Intermediate BTU gas; often used as a fuel, but it can be used as a starting point for the manufacture of high-BTU gas, methanol or other products.

system: A complete, internally-consistent sequential grouping of components necessary to exploit a resource.

tailings: Refuse material separated as a residue in the preparation of various products.

tailings pond: See settling pond.

tar: A dark brown or black bituminous liquid obtained by destructive distillation of organic material or more commonly a viscous oil.

tar sands: Hydrocarbon-bearing deposits distinguished from more conventional oil and gas deposits by the high viscosity of the hydrocarbons. They are not recoverable in their natural state by ordinary oil production methods.

technology: A general method for carrying out a given step in exploiting a fossil fuel resource.

thermal conductivity: The amount of heat that passes in unit time, through a unit volume (one cubic centimeter) of a substance when the opposite faces of the cube differ by one degree Celsius.

thermal efficiency: The ratio of the amount of energy in the products of a process to the amount of energy in the feedstocks.

throwaway: A process characterized by conversion of a feedstock to a waste product which is disposed, as opposed to processes in which this waste is used to regenerate the original feedstock.

topography: The configuration of a surface, including its relief, the position of its streams, lakes, roads, cities, etc.

trace element: An element present in a very small quantity.

trace pollutant: A pollutant present in a very small quantity.

trommel screen: A usually cylindrical or conical revolving screen used for separating substances such as rock, ore or coal into different sized fragments.

trona: A gray-white or yellowish-white mineral.

turbine: A device for generating electricity powered by the reaction and/or impulse of a stream of pressurized fluid (water, steam, liquid metal, etc.) and usually made with a series of curved vanes on a central rotating spindle.

U-V

upgrading: A processing step in oil shale and tar sands conversions whereby the raw oil is treated to remove sulfur and nitrogen and to make it more suitable for pipeline transport.

vaporized: Changed from the liquid state to the gaseous state without any change in chemical composition.

viscosity: The property of a fluid which indicates its ability to resist flow.

volatile: Readily vaporized at a relatively low temperature.

volatile matter: Those constituents of coal, exclusive of moisture, that are liberated from a sample when heated to 1750°F (for 7 minutes) in the absence of oxygen.

W

waste heat: Heat which is not utilized.

wastewater treatment: The treatment of collected sewage and runoff to remove nutrients, solids, etc. before the water is discharged into receiving water.

watershed: The whole region or area contributing to the supply of a river or lake; drainage area; catchment area or basin.

water supply: The treatment of water to make it fit for public consumption.

water tube boiler: A boiler in which heat is applied to the outside of tubes containing water and steam.

working capital: The amount by which current assets exceed current liabilities.

working fluid: Fluid in a power cycle that is heated by an energy source and then expanded through a turbine.

Z

zero discharge: The characteristic of a facility releasing no effluents to water, air or both.