PERMANENT EXEMPTIONS
(Final Regulations)

Generally Applicable to both New and Existing MFBI's:

1. <u>Lack of supply</u> - Adequate supply of alternate fuel will not be available during first ten years of MFBI's useful life (Subpart 503.31). (Only applicable to new units.)

   Demonstrate:

   (a) good faith effort made to obtain alternate fuel supply

   (b) alternate fuel not available during first ten years

   (c) solicitation of bids from at least five suppliers

2. <u>Cost</u> - Adequate supply of coal only available at a cost which substantially exceeds cost of imported petroleum during useful life of the installation (Subpart 503.32).

   Demonstrate:

   (a) good faith effort made to obtain alternate fuel supply

   (b) alternate fuel cost will substantially exceed the cost of imported petroleum (presently 1 to 1.3 ratio)

   (c) all capital items for which cash outlays are required as listed at the time of the decision to build

3. MFBI <u>site is limited</u> because alternate fuels are inaccessible or because of inadequate coal transportation, storage, or disposal facilities, or inadequate water supply (Subpart 503.33).

   Demonstrate:

   (a) physical limitation (not financial or legal limitations which can be included in the cost test) that cannot be overcome within five years after operation begins

(b) efforts made to overcome limitation

4. MFBI unable to satisfy FUA prohibitions without violating Federal or State environmental requirements. (Note: Denial of permit by environmental agency is not necessarily sufficient proof.) (Subpart 503.34).

   (a) unable despite good faith effort to comply with environmental requirements within five years after beginning operations

   (b) decision based solely on physical capacity--not cost of compliance

5. Inability to obtain adequate capital to build unit (Subpart 503.35).

   Demonstrate:

   (a) financial institutions contacted

   (b) corporate-wide test (five year financial experience at consolidated corporate level)--this is therefore a small business exemption

6. State or local requirements make construction and operation of alternate fuel burning MFBI infeasible (Subpart 503.36).

   Demonstrate:

   (a) waiver or variance attempted

   (b) in public interest

7. MFBI is a cogeneration facility whose benefits could not be obtained if alternate fuel were used (Subpart 503.37). (No final regulations issued. Notice and request for comments to be published.)

   Demonstrate:

   (a) petroleum or natural gas consumption is less than without cogeneration unit

   (b) in public interest

8. A <u>mixture</u> of coal or other alternate fuels and natural gas or petroleum is to be used (Subpart 503.38).

   (a) only minimum amount of petroleum or natural gas necessary for reliability and efficiency will be authorized

   (b) if percentage of petroleum or natural gas is less than 25% per year, qualifies for "automatic" exemption--based on certification by petitioner. However, 15% exempted from Primary Energy Source (Subpart 500.2) will not be applied in this case

   (c) engineering assessment and annual reporting

9. MFBI only for <u>emergency purposes</u> (Subpart 503.39).

   Demonstrate:

   (a) necessary for plant protection, human health needs, or production requirements because of fuel interruptions, equipment failures, or temporary environmental restrictions

   (b) emergency unit will operate only for emergency purposes

10. Exemption is necessary to meet <u>scheduled equipment outages</u> (Subpart 503.43).

   Demonstrate:

   (a) routine maintenance schedule could not be adjusted

   (b) outages in excess of 28 days annually averaged over a three year period cannot be met by alternate fuel use (less than 28 days annual average outages can receive exemptions based on certification by petitioner

   (c) MFBI must be used only when other units not operating

   (d) may be combined with emergency purposes exemption (both sets of criteria must be met)

TEMPORARY EXEMPTIONS
(Generally Parallel Permanent Exemptions)

Up to five years with possibility of extension of up to five more years.

Applicable to both new and existing MFBI's:

1. Adequate supply of alternate fuel is only available at cost which substantially exceeds cost of imported petroleum (presently 1 to 1.3 ratio) (Subpart 503.21). (Same as permanent except compliance with FUA must occur at end of exemption.)

2. MFBI site is limited because of inadequate alternate fuel transportation or storage except compliance with FUA must occur at end of exemption.)

3. MFBI unable to satisfy FUA prohibitions without violating Federal or State environmental requirements (Subpart 503.23). (Same as permanent except compliance with FUA must occur at end of exemption.)

4. Synthetic fuels derived from coal or from fuel other than natural gas or petroleum will be used by MFBI when exemption expires (Subpart 503.24). (Must show evidence of agreements to obtain synthetic fuels when exemption expires.)

5. Exemption would be in the public interest (Subpart 503.25). (Petitioner unable to comply with FUA during the period of the exemption.)

Applicable only to existing MFBI's:

1. MFBI will adopt "innovative technology" to use alternate fuel when exemption expires (Subpart 506.25). (Innovative technology not specifically defined except that "innovative characteristics" must be demonstrated.)

2. MFBI will be retired at expiration of the exemption (Subpart 506.26). (Need to show reason why alternate fuel cannot be used prior to retirement.)

CONDITIONS ON EXEMPTIONS

1. Mixtures - Applicant must demonstrate that use of a mixture is not feasible in order to receive any exemption other than a mixture exemption (Subpart 503.9).

2. Fluidized Bed - Any of the following exemptions may be denied if ERA determines that use of a method of fluidized bed combustion is feasible: lack of alternate fuel supply, site limitations, environmental requirements, inability to obtain adequate capital, state or local requirements, cogeneration, emergency purposes, or equipment outages (Subpart 503.10).

Terms and Conditions - ERA may require the recipient of an exemption to comply with certain terms and conditions, including compliance plans for temporary exemptions and effective fuel conservation measures for all exemptions. The terms and conditions authority has been used by ERA to restrict the use of other units at the site of the exempted unit (Subpart 503.12).

Specific terms and conditions are cited for each of the following permanent exemptions: lack of alternate fuel, mixtures, emergency purposes, and scheduled equipment outages. They include the requirement that all steam pipes must be insulated and all steam traps properly maintained.

PENALTIES

1. Criminal penalties: Willful violators of FUA are subject to a maximum fine of $50,000 or one year imprisonment or both for each violation.

2. Civil Penalties:
   (a) other violators of FUA are subject to civil penalties (to be assessed by ERA) of not more than $25,000 for each day of each violation

   (b) persons using natural gas or petroleum in excess of amount authorized in any exemption are subject to a civil penalty of up to $10/bbl or $3/Mcf per day of excess use (Example - MFBI penalized for use of natural gas or petroleum under a mixtures exemption that exceeds the exemption's terms and conditions.)

EXEMPTION REQUIREMENTS AND PROCEDURES

1. <u>Fuels Search</u> - (Subpart 503.16)
   (a) the Fuels Decision Report of the Interim Regulations has been replaced by a Fuels Search. It remains the most significant and burdensome part of the evidence required to demonstrate applicability of an exemption

   (b) the following information is required for any general use exemption, or a scheduled equipment outage for over 28 days:

      (1) demonstrate that the petitioner would qualify for an exemption in each case of alternate fuel use. The minimum number of fuels to be examined will be determined at the pre-petition conference

      (2) demonstration that a mixture using an alternate fuel is not economically or technically feasible (Subpart 503.9)

      (3) if ERA determines that a method of fluidized bed combustion of an alternate fuel could be used, demonstration that it is not feasible (Subpart 503.10)

(4) description of present and proposed natural gas/oil consumption (Subpart 503.14).

   (a) present and proposed consumption of unit

   (b) retirement plans of unit

(5) description of conservation measures taken or studied (Subpart 503.13):

   (a) conservation measures as to unit and facility

   (b) consumption figures, equipment, use expected benefits and problems

(6) analysis of environmental impact if exemptions are not granted (Subpart 503.15) (Guidelines published in 44 Federal Register 63740, November 5, 1979:

   (a) all permanent exemptions require:

      (i) description of facility and equipment needed to meet environmental requirements

      (ii) description of existing environment

      (iii) description of direct and indirect environmental impacts

      (iv) Federal, state and local requirements including air emission, water discharge and waste disposal limitations for each fuel

   (b) limited use exemptions may use "environmental check list" in the regulations

2. <u>Filing procedures for exemption petition</u>:

(a) prepetition conferences with ERA - define scope of petition including extent of Fuels Search, alternate fuels and sites to be researched, and exemptions to be considered (Subpart 501.2).

(1) request meeting by letter at least one week ahead:

(a) describe facility involved/need for new boiler

(b) describe proposed boiler and how it will meet need

(c) list exemptions desired

(2) recorded informal meeting(s) - ERA states that there may be no transcripts of meetings unless ERA determines otherwise. Submitted material not claimed to be confidential will be made available to the public

(3) waiver by ERA of any filing requirements, if any, in writing 30 days after conference (file copy with subsequent exemption petition)

(b) Petition - must include transmittal letter and request for confidential treatment of all proprietary information. (ERA has thirty days after filing of petition to advise that petition has been accepted or rejected for consideration. If not accepted, written notice will be provided regarding the reasons for rejection.) (Subpart 501.3).

3. <u>Review And Grant/Denial of Petition:</u>

(a) formal administrative process begins when petition accepted by ERA (indicated by publication in <u>Federal Register</u>) (Subpart 501.3)

(b) <u>at least</u> 45 days comment period after notice in <u>Federal Register</u> (Subparts 501.31 and 501.63) (Can be extended at ERA discretion)

(c) public non-adjudicatory hearings may be held during comment period (Subparts 501.33 and 501.34)

(d) ERA will publish an Environmental Impact Statement, when required, at least 30 days prior to final orders

(e) ERA will issue an order granting or denying the exemption within six months after the end of the public comment period. ERA may extend period by a notice in the <u>Federal Register</u> of a future date certain

  (1) temporary exemption <u>may</u> be granted within three months of publication in <u>Federal Register</u>

  (2) other exemptions <u>may</u> be granted within six months

  (3) environmental exemptions <u>may</u> be granted within twelve months

(f) terms and conditions may be placed upon any order granting an exemption to assure that exemption is not exceeded (any temporary exemption will have terms and a compliance plan to assure compliance with FUA when exemption expires) (Subpart 501.68)

4. <u>Administrative Appeal</u>:

No administrative appeal from final ERA exemption decisions (Subpart 501.13).

5. <u>Judicial Review</u>:

Sixty days after the publication in the <u>Federal Register</u> of a final order regarding an exemption petition, an aggrieved party may file a petition in the U.S. Court of Appeals for the Circuit in which the aggrieved party resides or has its principal place of business (Subpart 501.69).

PROHIBITION RULES AND ORDERS

<u>Existing MFBI's</u>

(1) Prohibition by order (Subparts 501.52 and 506.2).

(a) ERA may prohibit use of natural gas or petroleum in an MFBI if:

(1) MFBI has or previously had the technical capability to use an alternate fuel as a primary energy source

(2) MFBI has such technical capability or could have without substantial physical modification or substantial reduction in rated capacity

(3) financially feasible to use alternate fuel as a primary energy source

(b) ERA may hold conference prior to issuance of proposed order

(c) prior to issuance - proposed order published in Federal Register with three month comment period. (Proposed recipient of order must provide all available relevant information at that time)

(d) after three months ERA will state intention to proceed or not to proceed with proposed order. Recipients may show applicability of exemptions in next three months. Precluded from raising new information to rebut order if it was available during first three month comment period

(e) hearing is discretionary on part of ERA

(f) proposed order published in Federal Register with minimum of 45 days comment period

(2) Regulations on prohibition by rule for existing MFBI's are not yet published.

COAL GASIFIER COGENERATION POWER PLANT PROJECT

Harvey S. Bloomfield

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Coal Gasifier Cogeneration Power Plant Project

A unique power plant comprised primarily of commercially available equipment and using high sulfur coal in an environmentally acceptable manner is currently under study by NASA for installation at its Lewis Research Center (LeRC), Cleveland, Ohio, facility to supply total steam requirements together with a major portion of its electrical load. The plant size will be appropriate to industrial, or small utility, integrated gasifier combined cycle applications. The facility is of modular design that will provide both process heat and electricity at high efficiency.

Introduction

Until about a generation ago, stationary sources of power and heat - whether utility, industrial, residential or otherwise - generally relied on coal as their fuel. This practice continued until the 1950's, when plentiful supplies of low-cost oil and natural gas almost entirely displaced coal. New power and heat plants were constructed, and many existing plants converted, to use these cleaner, more easily-handled fuels.

Conversions were commonplace by the 1960's, with the trend accelerated by the nation's increasing environmental concerns. The process continued without letup into the first years of the past decade.

The OPEC oil embargo of 1973 created a startling awareness of a growing vulnerability: an increasing dependence on a dwindling supply of insecure and expensive foreign petroleum. For this reason, the United States has been challenged to find a suitable way to return to coal as a significant factor in our fuel mix for power and heat. This is particularly so because America's domestic coal reserves are greater than those of any other nation in the world and exceed on an energy content basis the world's known reserves of oil.

The revival of coal must be carried out in a manner consistent with both the spirit and the letter of justifiable environmental concerns. This is especially difficult for the eastern half of the country, including Ohio, where high sulfur coal is the predominant variety.

The NASA Lewis Research Center presents a typical example of present fuel usage in power and heat generation. Natural gas is used to fire boilers at the Center to provide steam for heating. Electric power is purchased from the Cleveland Electric Illuminating Company (CEI).

As a step toward dealing with America's future energy needs, national energy policy dictates that Government buildings and installations conserve natural gas and oil and wherever practical convert to coal in an environmentally acceptable manner.

NASA LeRC is now about to meet these requirements and, at the same time, undertake demonstration of technology, that could substantially benefit both industry and utility users, and also the eastern high sulfur coal producers of the country.

National Energy Policy

National Energy Policy (Figure 1) is directed toward conservation of oil and natural gas. Specifically, Public Law 95-620, The Power Plant and Industrial Fuel Use Act of 1978, restricts new oil or gas firing for major fuel burning installations. A major installation is defined as one that burns or uses more than 100 million Btu per hour - which covers an important segment of industry and the majority of electrical generating utilities. In addition, those installations that have used coal in the past are required to return to coal where practicable. At the same time, the national policy is aimed at the expanded use of coal in an environmentally acceptable manner. This is particularly difficult for potential users of high sulfur coal because of the emission of sulfates and nitrates and the potential formation of so-called "acid rain".

The NASA Lewis Research Center, along with all other government installations that are major fuel burning installations or that have previously used coal, comes under the requirements of Public Law 95-620.

In attempting to meet these regulations we have established our own set of requirements with respect to the use of coal in a cogeneration mode of operation (Figure 2).

Since we will likely have to buy coal on the spot market - as is the case with most other small coal users - we have established the requirement to burn not only high sulfur coal, but a wide variety of coal types and qualities. In addition, these coals must be utilized in an environmentally acceptable manner that minimizes not only stack emissions of particulates and sulfur and nitrogen oxides, but other controlled trace elements and all other waste streams.

We must also meet our seasonal steam heating demand which varies from a summer low of 20,000 lb/hr to a winter peak of 100,000 lb/hr.

NASA LeRC, along with other government agencies and industry, has an ongoing need to conserve energy. This added requirement would not be met by simply substituting coal for oil or gas.

The requirement of satisfactory payback is also of vital importance while for industry it is essential.

The power plant must utilize state-of-the-art technology for two reasons. First, the latest technology will be more efficient and reliable, and secondly, it will be more adaptable to future improvements with growth potential. This is particularly true for turbomachinery and combustion components.

And, finally, there is the critical requirement (particularly important to small users) of having waste products that are suitable for sanitary landfill without further treatment. Waste products must be disposable without treatment at reasonable cost, and with minimum handling and logistics.

Approaches for Utilization of High Sulfur Coal

There are a number of approaches that can be considered for the utilization of high sulfur coal (Figure 3). Atmospheric fluidized bed combustion is currently being used in some applications - pressurized fluidized beds have not yet been commercialized. In either concept the coal is intimately mixed with a sorbent - usually limestone in the case of the atmospheric fluidized bed. Desulfurization of the coal is accomplished directly in the fluidized bed with the resultant formation of calcium sulfate. This approach requires materials handling of limestone, as well as coal, as feedstock, and handling of ash and spent sorbent as waste products. This combination of waste products must be removed from the site and permanently disposed of.

The flue gas desulfurization approach is one that has been adopted by many utilities with varying degrees of success. With high sulfur coal, the stack or flue gases - products of combustion containing sulfur oxides - are scrubbed with water and a sorbent to form a sludge waste product. This approach typically exhibits problems of: reduced reliability and availability, increased water use, increased energy use, and difficulty in handling and disposing of sludge wastes. In addition, the scrubbers are a significant parasitic electric load and cause degradation in overall power plant efficiency.

Other approaches for high sulfur coal utilization are being studied, but are not yet commercialized. A promising approach is coal benefication - a technique that precleans and/or pretreats the coal to insure environmental acceptance of the combustion products.

Gasification is the approach that we have selected for early application at the NASA LeRC site. The rationale for this selection is shown in Figure 4.

It is the only process that can use high sulfur coal with proven commercially available acid gas removal cleanup techniques. In addition, since gasification requires only partical combustion, the consequent removal of acid gas (hydrogen sulfide) involves treatment of only a small fraction of the volume that would be treated by flue gas desulfurization methods - under some conditions this fraction is as low as one percent.

Some gasification techniques have the potential for accepting a wide variety of coal types and qualities. This is particularly important for small coal users who may have to buy "on the spot market".

Waste handling problems are minimized by virtue of low product volumes (ash and elemental sulfur) that are suitable for direct landfill use.

Also, there is good potential for achieving gaseous fuel emission standards, rather than solid (coal) fuel standards. This is due to the need for particulate and sulfur cleanup prior to gas turbine combustion to minimize corrosion in the turbine hot section. Also, when burning low Btu gas, the products of combustion - specifically oxides of nitrogen - are well within the new source stationary emission standards without additional treatment techniques.

The potential for high electrical conversion efficiency exists when gasification is integrated with a combined cycle power plant. In addition, the cogeneration option can provide significant gains in coal utilization efficiency by using waste heat from the gas turbine to raise steam for process heating.

Coal to Gas Cogeneration Power Plant Concept

A simplified schematic diagram of the concept is shown in Figure 5. Coal and oxidant are reacted in a pressurized gasifier to generate a hot dirty fuel gas whose temperature depends on the gasifier type - from 700°F to about 2600°F. The sensible heat of the fuel gas is recovered in a cooler by raising high pressure steam. The cooled fuel gas is then routed to a commercial sulfur cleanup process. Cold fuel gas of "pipeline quality" cleanliness is then combusted in a gas turbine producing electricity and a high temperature combustion product exhaust. The exhaust is used to generate high pressure steam in a boiler or heat recovery steam generator. After combination with the high pressure steam from the cooler, the total steam flow is passed through a steam turbine to generate additional electricity. By using a commercial extraction steam turbine, low or intermediate pressure steam for heating can be removed for on-site use. In addition, it is important that steam used for heating has performed shaft work in the steam turbine before extraction. This not only increases electrical output, but allows the extraction steam turbine to follow steam load demand variations while the gasifier and gas turbine components operate at steady state or full load.

Project Rationale

Figure 6 lists the major reasons for our interest in this system concept. The national requirement to convert to coal firing is based on conserving oil and natural gas. The national need for an efficient, economically attractive option for burning high sulfur eastern coal exists both for industrial and federal installations like NASA Lewis. It is believed that the coal gasification combined cycle power plant is that option and that there is an urgent need for a timely demonstration of this technology.

In converting over to high sulfur coal firing, the Lewis Research Center must modify or replace its existing steam plant. It is this confluence of needs that creates the opportunity for the federal government to meet national requirements and at the same time characterize and demonstrate this important technology for industry and the utilities.

Coal Gasifier Cogeneration Power Plant Project

Project Elements

Figure 7 illustrates the key groups that comprise the interactive elements of the project. Within NASA LeRC we have utilized our Systems Analysis group which has considerable experience analyzing industrial cogeneration and utility systems. Our Master Planning group has the responsibility for all future facilities and their impact on the Center.

The local utilities involved in the project are the Cleveland Electric Illuminating Company and the East Ohio Gas Company . The Electric Power Research Institute, because of their background in coal gasification and their interest in commercialization of large coal gasification combined cycle power plants is informed of progress and results of this project.

Following initial studies by our System Analysis group, a competitive procurement was completed and the Davy McKee Corporation was selected as the Architect-Engineer to conduct a conceptual design study to further evaluate the technical and economic feasibility of a Gasifier Cogeneration Power Plant to be sited at NASA LeRC.

In order to insure objectivity in the study results a Design Review Team of technical specialists was appointed to provide an ongoing independent review and prepare recommendations for NASA management.

The NASA Headquarters role in this project has been to provide initial financial support and to integrate this program with energy savings and coal conversion programs within NASA.

The Department of Energy is involved because of their expertise and federal responsibility in coal gasification technology development and applications to industry and the utilities.

Feasibility Study

The feasibility study contract details are shown in Figure 8. The contract elements and schedule are shown in Figure 9. Initial effort was aimed at selecting a suitable site at Lewis and perform a detailed screening and selection of feasible gasifiers. From an initial list of about 35 candidate gasifiers, five were selected that best fit the evaluation criteria. The most attractive baseline configuration, considering performance and component costs, was then subject to an initial system capital cost estimate. Component and system selections, siting, performance and costs were reviewed by the Design Review Team.

An important consideration of the study was power plant size or output. The factors that affect plant size are shown in Figure 10. These include: available gas turbomachinery package size, acceptable coal and waste handling facilities and logistics, available sizes of gas particulate and sulfur removal cleanup systems, maximum steam demand for cogeneration, manpower and operating cost constraints, regulations for siting and emissions that are size-related, and capital cost constraints.

An additional size-related factor that is peculiar to the NASA Lewis Research Center is related to electricity demand as shown in Figure 11. A typical week shows a weekend load of about 5 megawatts with workday evening peaks of up to 200 megawatts. These high loads are due to operation of the supersonic wind tunnel facilities. Evaluating these widely varying demands with other sizing factors led us to a baseline configuration nominal output of about 20 megawatts electric.

The impact of this size is shown in the electric load duration curve of Figure 12. This curve is based on an annual integration of hourly data and shows that the load will typically exceed 20 megawatts about 25 percent of the time. The upper levels of the curve are not shown but would indicate that the maximum load of about 220 megawatts is only attained for a few hours every year. During the summer, when steam demand is low (20,000 lb/hr), the extraction steam turbine generates somewhat more electricity than the winter case when steam demand may exceed 100,000 lb/hr.

At those times when electrical demand exceeds the power plant rating, electricity is imported from the utility. When electrical demand is less than plant rating electricity is available for export to the utility grid. For a nominal 20 MWe plant rating the total energy imported is about equal to that exported, although the curve indicates that power is purchased only 25 percent of the time and sold 75 percent of the time. Also, both import and export can occur on any typical day.

The initial tasks of the feasibility study were the establishment of gasifier selection criteria and subsequent screening and selection of a baseline gasifier. Figure 13 shows two of the key discriminators out of the total of twenty used, and the five gasifier candidates that survived screening. Of these, the Westinghouse Fluidized Bed Gasifier was selected for the baseline conceptual design. The other major components of the power plant, as shown in Figure 14, are all commercially available hardware.

The heat exchanger category includes a raw fuel gas cooler that will cool 1850°F gas to 400°F by generating 750°F steam for use in the steam turbine. At these temperatures materials problems in the gas cooler should be minimized and permit current commercial design practice to be used.

After all system components were identified, a preliminary cost comparison with two alternative concepts was conducted. The results of this comparison as a function of first year operating savings are shown in Figure 15. The two alternate systems are: (1) a high sulfur coal-fired steam plant with flue gas desulfurization (scrubber); and, (2) a low sulfur coal-fired steam plant with electrostatic precipitator (baghouse). Both of these alternate concepts produce steam for heating only and do not generate electricity. The cost of the high sulfur coal cogeneration power plant concept (Co-Co-Gen) is shown for two different electricity rate scenarios. The declining block rate point is indicative of our current electrical utility rate structure, while the other point represents an averaged flat electricity rate structure.

The scrubber and baghouse concepts are characterized by relatively low capital costs, but both exhibit negative first year operating savings. For the coal gasifier cogeneration power plant first year annual savings of four to seven million dollars are indicated - depending on electrical rate structure. These savings are comparable to the total current annual utility costs for the Center.

In terms of economic assessment of the coal-fired options for NASA LeRC, a 20 megawatt gasifier combined cycle cogeneration power plant appears to be economically attractive. A payback of about four and half years could be achieved using the flat electrical rate scenario. The other options, although less capital intensive, showed payback periods of up to twenty years in this evaluation.

A technical assessment of the key components of the gasifier cogeneration power plant is shown in Figure 16. For the gasifier selected, a modest size increase from the current process development unit would be required. Coal feed for the NASA Lewis power plant will be about 250 tons per day for two gasifiers operating in parallel. Integration of two simultaneously operating gasifiers firing a single gas turbine has not been demonstrated, but is required to verify multiple module operation. The turbine combustor must be modified for low Btu gas firing and compressor and turbine flow rates must be matched. These turbine modifications do not appear to be major technical problem areas. The design of an integrated controls system has not been demonstrated for this system, but is not expected to reoresent a major technical barrier given that the dynamic and transient performance of each major component has been adequately characterized. This characterization is an important part of system demonstration. In summary, no fundamental technical feasibility issues are seen for the power plant concept.

An environmental assessment of the concept has concluded that no barriers to environmental acceptance are foreseen (Figure 17). This concept results in minimum waste handling requirements. Coal pile water runoff is treated conventionally through a limestone bed and collected in a retention basin. The flue gas effluents will be well within environmental standards and the selection of a low Btu gasification process will allow combustion without water injection for NO_x suppression. Also, as part of this project, we envision carrying out a major environmental impact assessment to establish a precedent for potential industrial applications.

A representation of the power plant environmental impact is shown in Figure 18. For a 250 ton per day high sulfur coal input we would expect ten to fifteen percent ash (25 tons/day), and three to five percent sulfur (10 tons/day). These products should be suitable for sanitary landfill. In addition, the acid gas removal process would generate a relatively small quantity of contaminated waste that must be disposed of on an annual basis.

Project Schedule

In terms of overall project schedule, Figure 19 indicates a total of five years from start of conceptual design to completion of system characterization. Included in this schedule are significant time periods for acquisition, or procurement, and characterization of the power plant. The almost two year system characterization time period would be used to check out all components and completely define all system operating parameters. This effort is aimed at reducing risk for subsequent commercial application and is a key part of our project philosophy.

Conclusion

To be considered as a significant coal alternative in a broad sense, the Gasifier Combined Cycle must satisfy a variety of requirements. Some important current utility and industrial cogeneration requirements are shown in Figures 20 and 21, respectively.

The technical and economic feasibility study for a Gasifier Cogeneration Power Plant to be located at the NASA Lewis Research Center, because of design modularity, has shown that both utility and industrial requirements can be met. In addition, the study results have provided the basis for proceeding with the project whose completion will provide a system technology demonstration that will verify the potential benefits shown in Figure 22.

The Coal Gasifier Cogeneration Power Plant Project is planned to meet the needs not only of the NASA Lewis Research Center, but, at the same time, reduce the commercial risk for industry and utilities by fully verifying and demonstrating this important technology. The project also represents a cooperative venture of industry and government to accelerate commercialization so as to achieve massive implementation thereby making a significant contribution to energy independent while minimizing environmental intrusion.

FIGURE 1
NATIONAL ENERGY POLICY

NATIONAL ENERGY POLICY IS DIRECTED TOWARD:

- CONSERVATION OF OIL AND NATURAL GAS
- PUBLIC LAW 95-620, POWERPLANT AND INDUSTRIAL FUEL ACT OF 1978

  PROHIBITS NEW OIL/GAS FIRING FOR MAJOR FUEL-BURNING INSTALLATIONS

  REQUIRES RETURN TO COAL BY 1990

- EXPANDED USE OF COAL IN AN ENVIRONMENTALLY-ACCEPTABLE MANNER

CS-80-2402

FIGURE 2

NASA LEWIS COGENERATION

POWER PLANT REQUIREMENTS

- SHOULD UTILIZE HIGH SULFUR (OHIO) COAL IN AN ENVIRONMENTALLY ACCEPTABLE MANNER
- PRODUCE 20 000-100 000 lb/hr STEAM
- CONSERVE ENERGY
- PAYBACK SHOULD BE SATISFACTORY
- MUST BE "STATE OF ART" TECHNOLOGY
- WASTE PRODUCTS SUITABLE FOR SANITARY LANDFILL

CS-80-2397

FIGURE 3

APPROACHES FOR UTILIZATION OF HI SULFUR COAL

- FLUIDIZED BED COMBUSTION
- FLUE GAS DESULFURIZATION
- GASIFICATION
- OTHERS

CS-80-2403

FIGURE 4

WHY GASIFICATION

- ONLY PROCESS THAT UTILIZES HI SULFUR COAL WITH COMMERCIALLY AVAILABLE CLEANUP
- ACCEPTS A WIDE VARIETY OF COAL TYPES
- MINIMIZES WASTE HANDLING PROBLEMS
- POTENTIAL FOR ACHIEVING GAS STANDARD EMISSIONS
- POTENTIAL FOR HIGH ELECTRICAL CONVERSION EFFICIENCY COUPLED WITH HIGH QUALITY WASTE HEAT

CS-80-2396

FIGURE 5

COAL TO GAS COGENERATION POWERPLANT CONCEPT

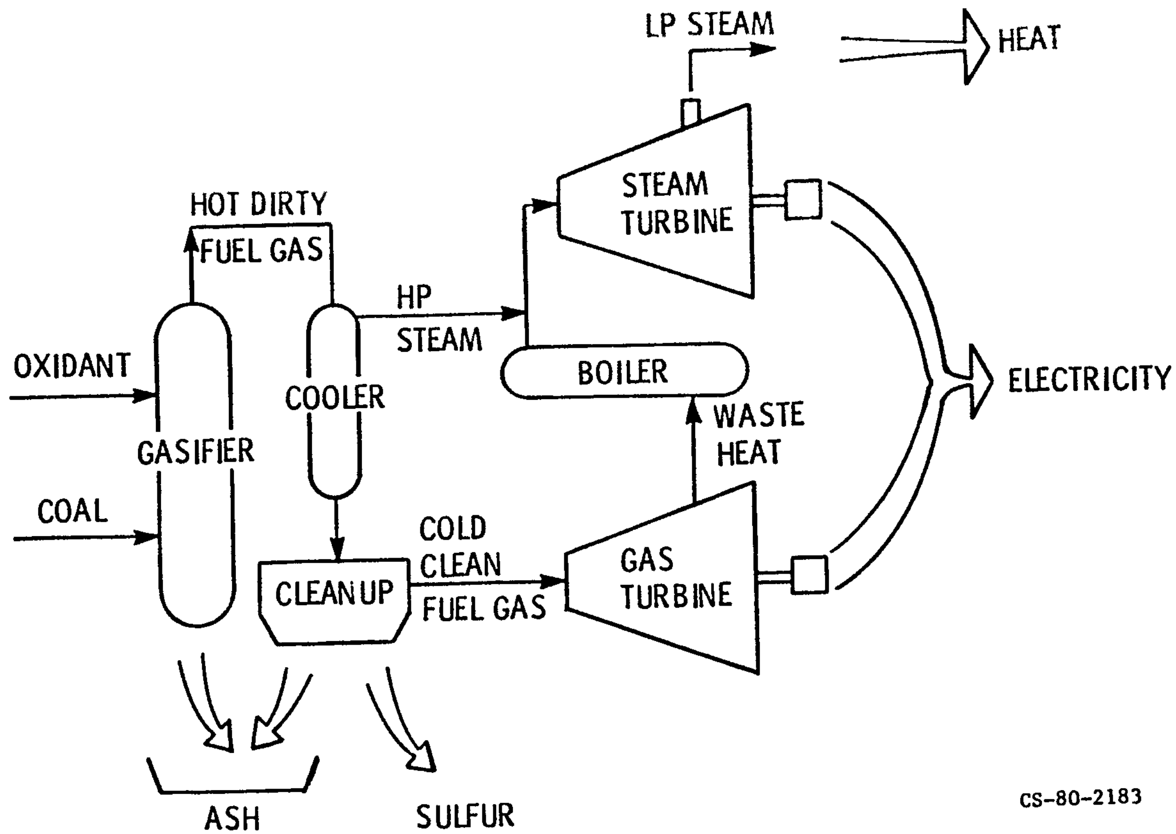


FIGURE 6
WHY ARE WE DOING IT?

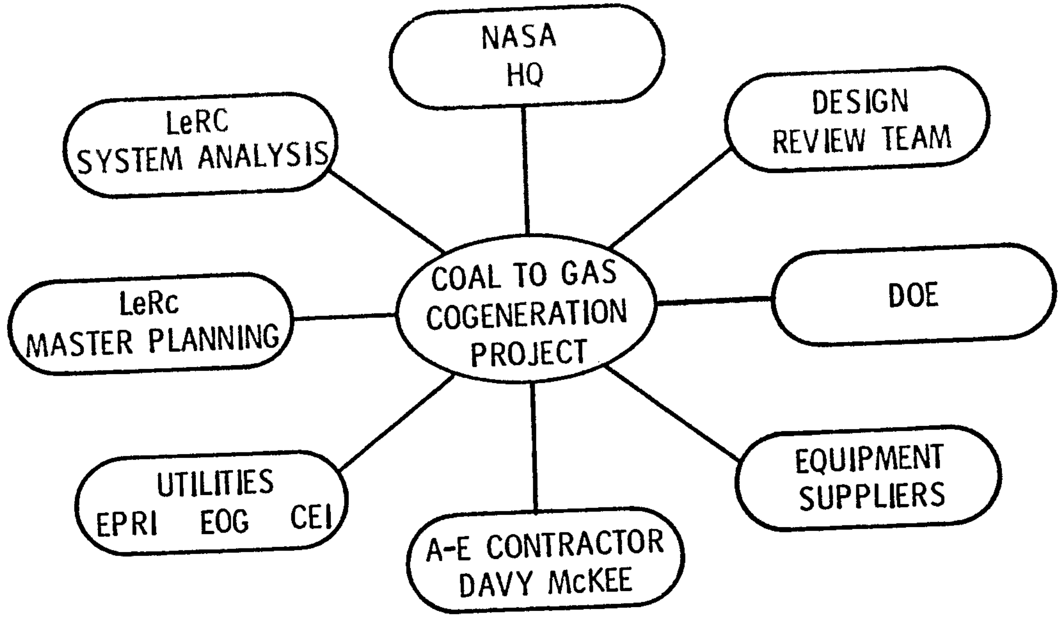
- NATIONAL NEED TO CONVERT TO COAL FIRING
- NATIONAL NEED TO CONSERVE OIL AND NATURAL GAS
- NATIONAL NEED FOR EFFICIENT, ECONOMICALLY ATTRACTIVE OPTION FOR BURNING HIGH SULFUR COAL
- NATIONAL NEED TO PROVIDE A REAL DEMONSTRATION AS QUICKLY AS POSSIBLE
- LeRC NEED TO MODIFY, REFURBISH OR REPLACE EXISITING POWER PLANT

NATIONAL NEEDS AND LEWIS NEEDS = OPPORTUNITY

CS-80-2391

FIGURE 7

PROJECT ELEMENTS



CS-80-2407

FIGURE 8

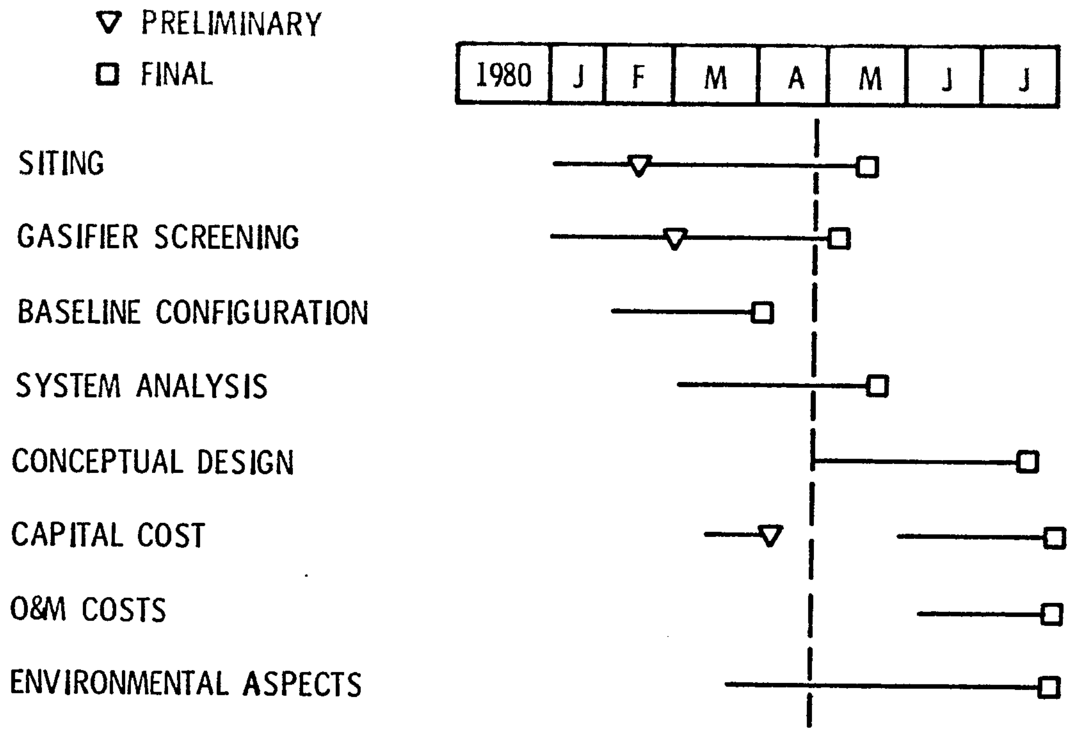
COAL-TO-GAS COGENERATION POWER PLANT STUDY

CONTRACT

- OBJECTIVE: CONCEPTUAL DESIGN TO ASSESS TECHNICAL AND ECONOMIC FEASIBILITY
- DAVY McKEE CORPORATION
  CLEVELAND, OHIO
- $205 000
- CONTRACT START: DECEMBER 21, 1979
- CONTRACT END: JULY 1980

CS-80-2405

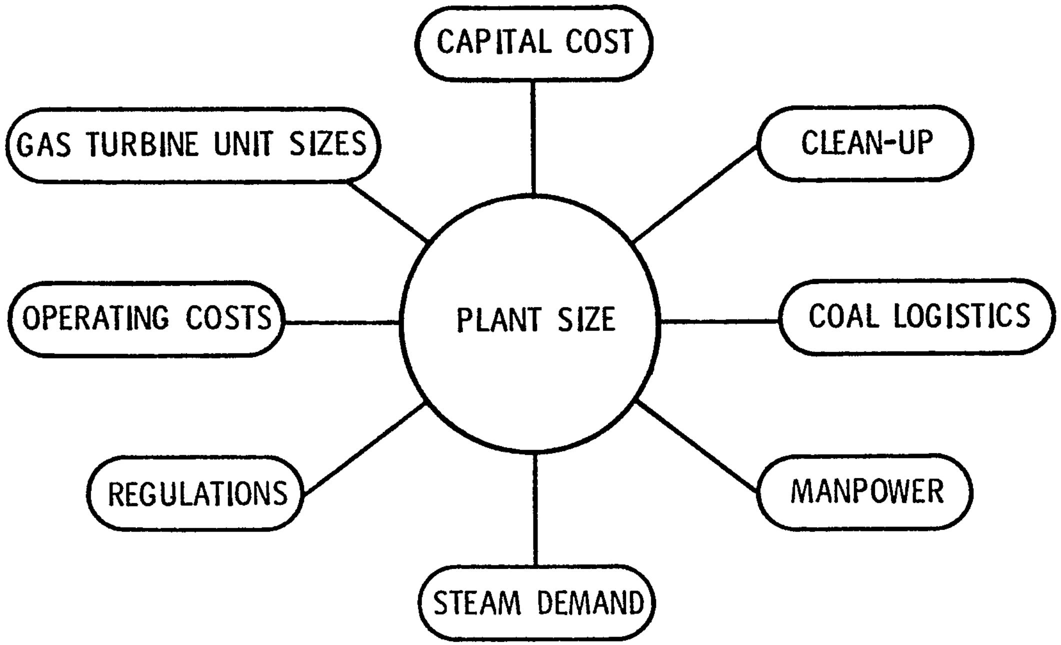
FIGURE 9
STUDY PLAN



CS-80-2395

FIGURE 10

SIZING FACTORS

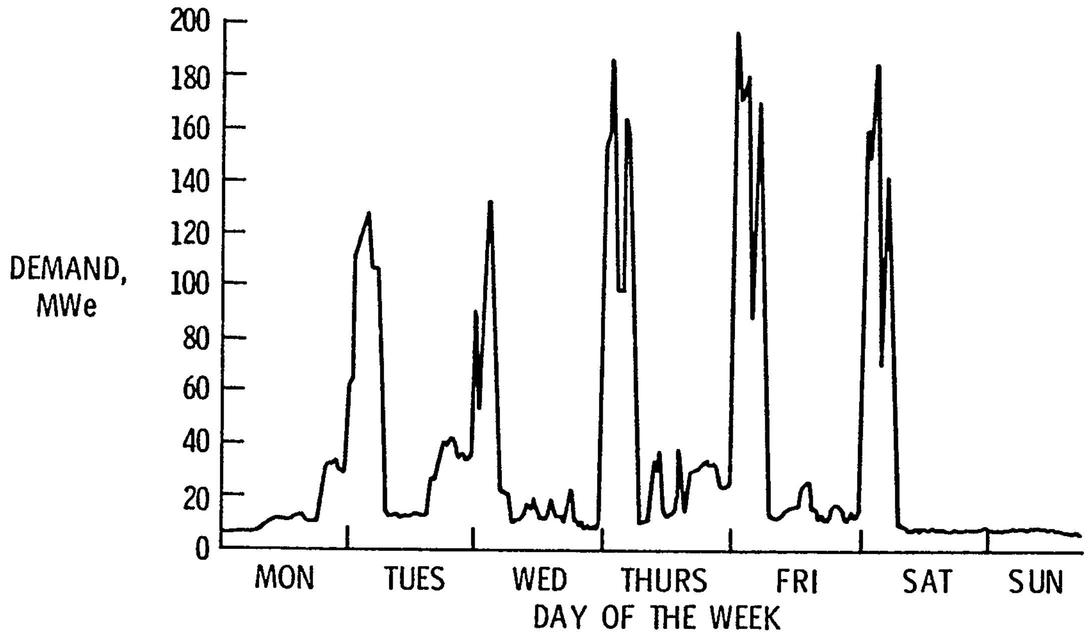


CS-80-2389

FIGURE 11

EXAMPLE OF DAILY ELECTRIC DEMAND

AUGUST 1979

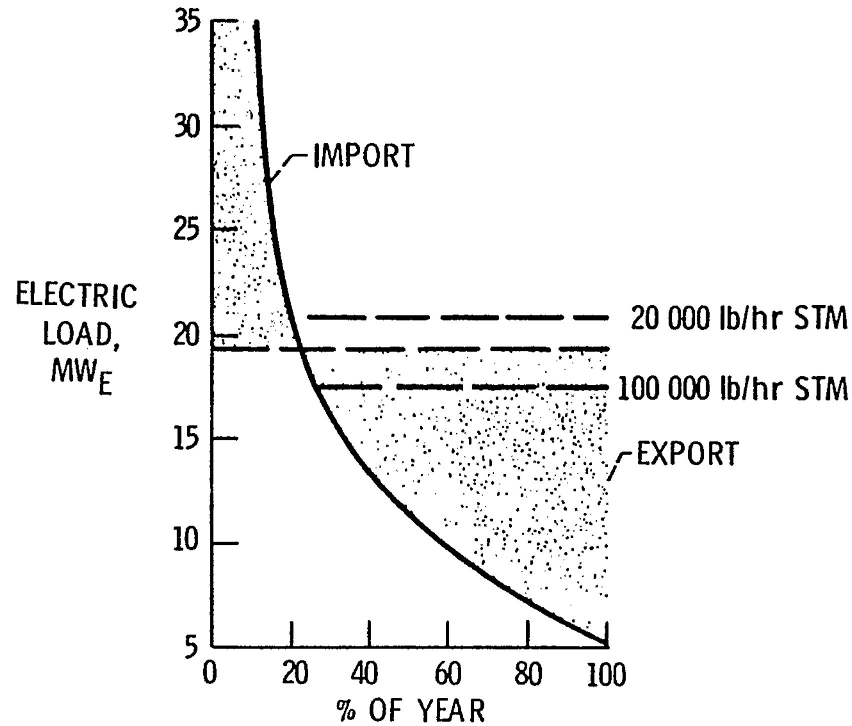


CS-80-2399

FIGURE 12

OPERATION OF PRELIMINARY BASELINE CONFIGURATION

20 MW_E NOMINAL RATING



CS-80-2400

FIGURE 13
GASIFIER SELECTION

DISCRIMINATORS

- ABILITY TO USE WIDE VARIETY OF COAL (INCLUDING OHIO)
- NEAR-COMMERCIAL STATUS OF DEVELOPMENT

CANDIDATES

- WESTINGHOUSE FLUIDIZED BED
- IGT U-GAS FLUIDIZED BED
- TEXACO ENTRAINED FLOW
- B & W ENTRAINED FLOW
- BRITISH GAS SLAGGING FIXED BED

CS-80-2404

FIGURE 14
OTHER EQUIPMENT

- CLEAN-UP SYSTEM
- TURBOMACHINERY
- HEAT EXCHANGERS
- COAL HANDLING EQUIPMENT

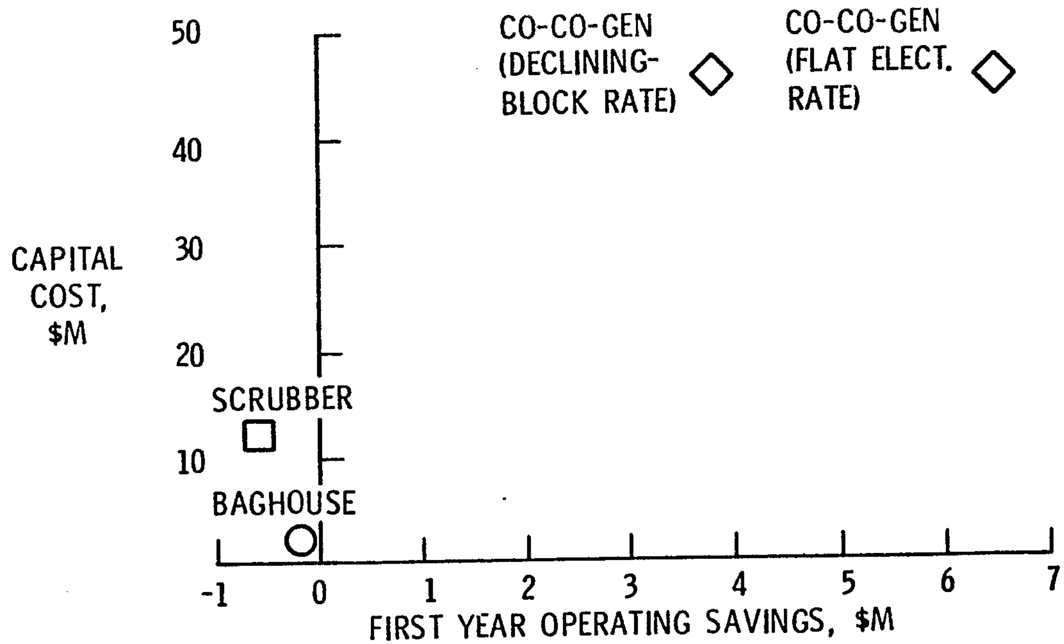
COMMERCIALLY AVAILABLE

CS-80-2393

FIGURE 15

COMPARISON OF OPERATING SAVINGS AND CAPITAL COSTS FOR SEVERAL ALTERNATIVE POWER PLANTS

1980 DOLLARS



CS-80-2398

FIGURE 16
TECHNICAL ASSESSMENT

GASIFIER

- SCALE UP MAY BE REQUIRED
- INTEGRATION MUST BE DEMONSTRATED

GAS TURBINE

- COMBUSTOR MUST BE MODIFIED FOR LOW AND MEDIUM BTU GAS
- TURBOMACHINE MATCHING MUST BE EVALUATED

CONTROLS

- INTEGRATION AND OPERATION OF COMPONENTS TO OPERATE AS A SYSTEM HAS NOT BEEN DEMONSTRATED

SUMMARY

- NO FUNDAMENTAL FEASIBILITY ISSUES EXIST

CS-80-2392

FIGURE 17
ENVIRONMENTAL ASSESSMENT

- NO BARRIERS TO ENVIRONMENTAL ACCEPTANCE
- WASTE REMOVAL (ASH, SULFUR) IS MINIMAL
- COAL PILE RUN OFF (H_2O) IS TREATED
- EFFLUENTS (NO_X, SO_X, PARTICULATES) WILL MEET ENVIROMENTAL STANDARDS
- EXTENT OF ENVIRONMENTAL IMPACT ASSESSMENT WILL BE DETERMINED

CS-80-2406

FIGURE 18

NASA LEWIS ENVIRONMENTAL IMPACT

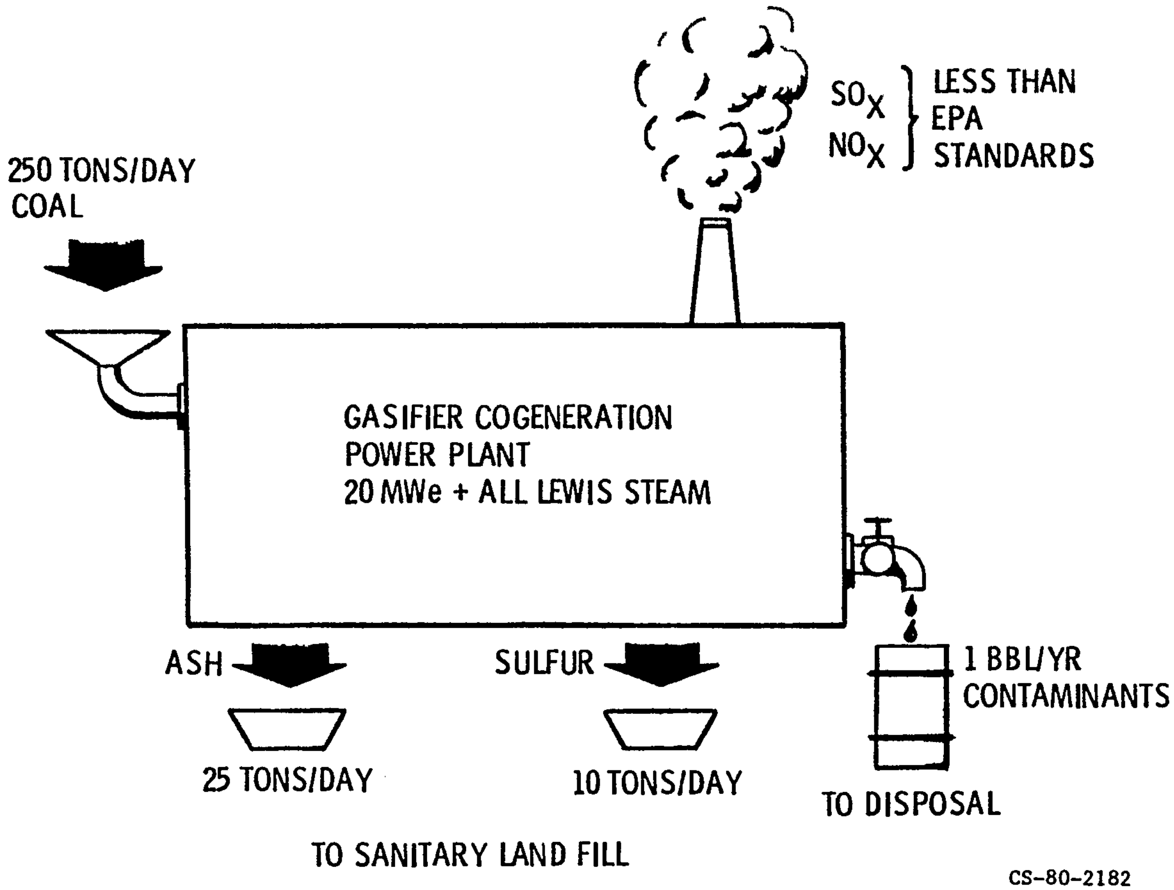
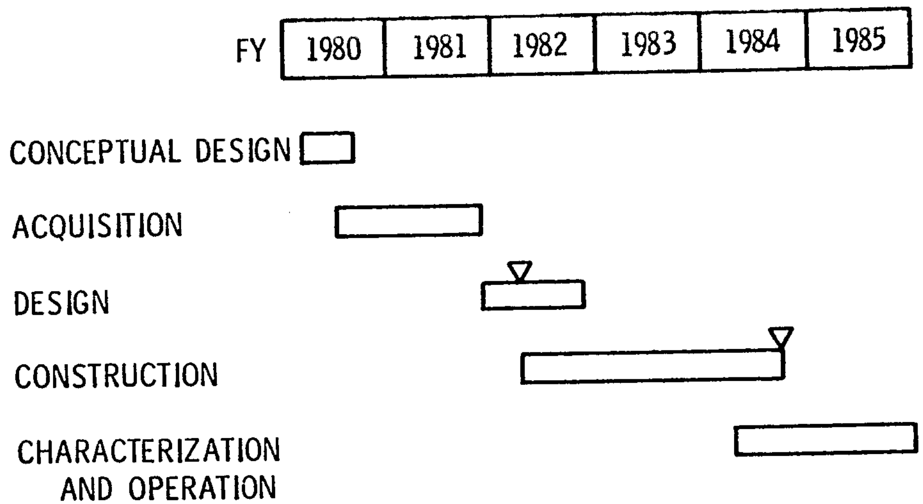


FIGURE 19

GASIFIER COGENERATION POWERPLANT



CS-80-2390

FIGURE 20

CURRENT UTILITY REQUIREMENTS

- 50% BACK-OUT OF OIL BY 1990
- NO NEW OIL OR NATURAL GAS PRIMARY FUEL FIRING
- ENVIRONMENTAL COMPLIANCE (NO ACID RAIN)
- SITING FLEXIBILITY
- INCREASED RELIABILITY AND AVAILABILITY
- ABILITY TO ACCOMODATE UNPREDICTABLE LOAD GROWTH
- REDUCED CONSTRUCTION TIMES
- ECONOMICALLY COMPETITIVE
- IMPROVED EFFICIENCY
- GROWTH POTENTIAL
- FUEL FLEXIBILITY

CS-80-2401

FIGURE 21

INDUSTRIAL COGENERATION REQUIREMENTS

- RAPID PAYBACK
- ATTRACTIVE ROI
- USE WIDE RANGE OF COAL
- SITING FLEXIBILITY
- MINIMIZE LOGISTICS
- LOWEST EMISSIONS POTENTIAL (MINIMIZE OFFSETS)
- GROWTH POTENTIAL
- ACCEPTABLE RELIABILITY AND AVAILABILITY
- MINIMUM LAND REQUIREMENTS
- SHORT CONSTRUCTION TIMES

CS-80-2394

FIGURE 22
BENEFITS OF GASIFIER COMBINED CYCLE

- ACCOMODATES A WIDE RANGE OF COALS INCLUDING EASTERN HIGH SULFUR
- MINIMUM ENVIRONMENTAL EMISSION AND WASTES
- HIGH EFFICIENCY
- RAPID MODULAR CONSTRUCTION
- SITING FLEXIBILITY
- ECONOMICALLY ATTRACTIVE
- POTENTIAL FOR REPOWERING EXISTING OIL AND NATURAL GAS UTILITY CAPACITY
- ONLY NEAR-TERM ALTERNATIVE WITH GROWTH POTENTIAL

$\boxed{\text{NEEDS SYSTEM TECHNOLOGY DEMONSTRATION}}$

CS-80-2408

COMMERCIALIZATION OF COAL GASIFICATION IN THE U.S.
-- GREAT PLAINS GASIFICATION ASSOCIATES --

Rodney E. Boulanger

COMMERCIALIZATION OF COAL GASIFICATION IN THE U.S.
-- GREAT PLAINS GASIFICATION ASSOCIATES --
JUNE 20, 1980

Mr. Rodney E. Boulanger
Vice President of Financial Administration
American Natural Service Company
Detroit, MI. 48226
United States of America

Great Plains Coal Gasification Project

Introduction

The Great Plains coal gasification project is, as the title implies, a project designed to convert coal into synthetic natural gas. The plant is designed to produce an average of 125 million cubic feet per day of high-BTU, pipeline quality synthetic gas from North Dakota lignite coal. The plant would be located at the mine site in North Dakota, use water from the Missouri River and produce gas that is completely interchangeable with natural gas. The five companies that are partners in the project are affiliates of companies which supply approximately one-third of the interstate natural gas used in this country, in turn natural gas represents approximately 30% of our Nation's energy requirement. The total cost of the project is expected to be about $1.5 billion including the mine, but excluding capital costs during construction and any required new pipeline facilities. Approximately $1.2 billion of the project costs would be debt and the remainder equity. The principle parties to the project are identified in Exhibit I.

Background

The project was initiated in the early 1970's as an outgrowth of a concern for the availability of future supplies of energy in the United States. You might recall that in the 1960's annual discoveries of domestic oil and natural gas had fallen below production levels; thus, this Nation with an economy so dependent on energy was turning increasingly to foreign imports and non-traditional sources to meet its needs.

After considerable study, American Natural concluded that coal gasification represented a promising source of domestic supplies of synthetic natural gas. However, while low and medium BTU coal gasification is not new, and over 10,000 installations existed in this country in the 1920's no attempt had been made to produce high BTU gas and no coal gasification project of the size contemplated had ever been built in this country. Add in changes in technology, a plant site area remote to major construction projects and projected costs much higher than the industry was accustomed to, and the result is a project over-flowing with management challenges, of which financing was the key issue.

By 1972, American Natural had negotiated an arrangement with North American Coal Company whereby North Dakota lignite coal reserves, now approaching four billion tons, would be dedicated to American Natural. In 1973, American Natural seriously began work with the present engineering contractors; Lurgi Mineraloltechnik Gmbh, Lummus Company and Kaiser Engineers, Inc., and decided to go forward with a Lurgi high BTU coal gasification project. In 1974, a plant site and State Water Permit were acquired, environmental work commenced and 12,000 tons of North Dakota lignite were tested in South Africa in a commercial size Lurgi gasification plant.

Early in 1975, American Natural filed an application with the Federal Power Commission (now the Federal Energy Regulatory Commission) for approval to construct a 250 million cubic feet per day gasification plant estimated to cost $783 million (1974 dollars) and go into operation in September, 1979. With that step, American Natural commenced what has become a more lengthy and difficult process than anyone ever imagined.

The project has changed considerably from that initial filing, and a review of some of the changes and the reasons for them are important to understanding the current status of the project.

First, the crux of any project financing is establishing sufficient credit to attract debt capital into the project. In the case of the Great Plains project, American Natural had a first of a kind project, which apart from the more traditional technical and economic considerations to financing, also involved important regulatory risks. These considerations coupled with the amount of capital required for the initial project, as compared to American Natural's net worth, made it clear from the outset that it was financially imprudent for American Natural to provide debt guarantees for such a project. American Natural would supply the equity but some other vehicle would have to be devised to support the debt.

The debt credit support for that initial project design contemplated Federal loan guarantees. However, despite the OPEC Oil Embargo and support from President Ford, enabling legislation failed to pass Congress, on one occassion missing by a single vote.

During this period of time, project costs increased dramatically because of the impact of extraordinary high rates of inflation in 1974 and 1975. Consequently, it was decided that construction, environmental and financial problems would be reduced if the project were constructed in two phases. Accordingly, the proposal before the Federal Power Commission was modified to construct the plant in two 125 MMCFD phases.

Still, the capital requirements were great and with continuing delays in obtaining loan guarantees and regulatory approvals, American Natural sought other participants. In the summer of 1977, The Peoples Energy Corporation (formerly the Peoples Gas Company) which had a coal gasification project in the planning stages, joined as a co-owner, sharing in the interim financing responsibility. The revised application before the FPC continued to be based on the subsequent availability of Federal loan guarantees.

Early in 1978, it did not appear that loan guarantees would be available on a timely basis. However, the Department of Energy was seeking key projects as part of its energy supply initiatives which DOE had developed and transmitted to Congress. Coal gasification represented a key element in that plan and the Great Plains project was by far the most advanced project in planning, permits, resources, etc. Then Deputy Energy Secretary, Jack O'Leary encouraged American Natural and Peoples to proceed with the project and to seek an alternative financing plan.

Thus, the formation of the Great Plains Gasification Associates, a partnership consisting of subsidiaries of five major companies: American Natural, Peoples, Columbia Gas System, Inc., Tenneco, Inc., and Transco Companies, Inc.

Concurrently, discussions began with 3 banks (Citibank, N.A., Bank of America and Morgan Guaranty Trust Company of New York) to determine the terms and the essential elements required to rely upon ratepayers and the regulatory process for credit support for the debt.

After several months of intense negotiations, the discussions with the banks were successfully concluded and resulted in a 26 page commitment letter which would provide up to $1.4 billion under certain terms (Exhibit II summarizes many important ones) and conditions. I will elaborate later on the essential elements or conditions precedent to establishing adequate credit support. At this point, it is important to note that an innovative and unique debt financing plan had been developed. However, its implementation required the unequivocal approval of the FERC. The Department of Energy then intervened before the FERC both in support of the project and the financing approach.

Finally, on November 21, 1979, after further hearings and briefings, a decision was finally obtained from the Federal Energy Regulatory Commisssion (FERC), the successor to the Federal Power Commission, approving the key elements of the plan. However, the regulatory process has not ended, for the FERC order was appealed to the U.S. Court of Appeals by four parties to the case: New York Public Service Commission, State of Michigan, Consumers Council of Ohio and General Motors. One of the major objections is the very issue of the allocation of risks between ratepayers, taxpayers and companies that is embodied in the financial plan.

Subsequent amendments and rehearings to the FERC order were and are being requested. The Commission did issue one amendment to the order on January 21, 1980 and another is in the process. These amendments were necessary to make the order workable from the standpoint of the banks and the partnership.

With this much behind us, the current status of the project is as follows:

The project is ready to begin construction with all major permits, licenses and approvals obtained, with the exception of a final and non-appealable FERC order. Water and coal have been secured. Contractors have been hired. The environmental aspects have been thoroughly analyzed and the project has the full support of the State of North Dakota. The plant design and project management system have been reviewed, reviewed and reviewed - the one positive aspect of the delays is that it has given management, engineers, contractors and consultants more time to design and engineer the project prior to start of construction than usually occurs in a major construction project.

The project holds substantial promise for demonstrating that coal gasification is an economical, efficient and environmentally superior method of using our vast coal reserves. It appears less costly than imported oil on a present value basis, thanks to OPEC pricing, and holds promise of reducing dependence on foreign imports. Building this project will not only demonstrate the desirability of coal gasification, but it will add immensely to our pool of knowledge of the environmental, regulatory, economic, financial and management aspects of constructing and operating a major synthetic fuel installation.

Financing remains a hurdle. While syndication of the bank loan is likely given a final FERC order, a final FERC order is not possible until the court appeals have been resolved.

Loan guarantees are finally close to reality but not in time to begin full construction this summer. The legislation approving the Energy Security Corporation has been accepted by the joint House-Senate Conference Committee considering an Omnibus Energy bill. This bill was expected to be signed into law on July 4, 1980. After enactment, a certain amount of time will be required before applications can be solicited under the Act and, of course, it takes time to process applications and negotiate terms, assuming that our project qualifies and is accepted. However, it is important to note that the FERC order requires Great Plains to actively seek such loan guarantees to replace the ratepayer based credit support.

While continuing our pursuit of permanent financing, we filed an unsolicited loan guarantee application for one year of funding under the Federal Non-Nuclear Energy Research and Development Act. On May 29, 1980, the Department of Energy issued a notice accepting our application for evaluation, and the application is currently being evaluated. Should the loan guarantee be committed, we hope to initiate construction expenditures as soon as possible thereafter to minimize any further delays in the project. Full permanent financing for the project would come with either a resolution of the appeals, or preferably, loan guarantees for the entire project.

Financing Plan - Ratepayer Credit Support

Turning now to the details of the FERC approved financing plan, I would first note the concept, which is basically that the cash flow to investors and lenders arises from charges to the affiliated pipelines of Great Plains, and then on a timely basis to customers of the pipeline companies. To achieve this result, it was necessary for the FERC to approve tariffs for Great Plains and the pipelines which would provide the form of security required for both normal debt service and abandonment, both after and prior to completion of the project.

The FERC order provides these necessary tariff elements to establish this security. The cornerstone is obviously the recovery of debt under all circumstances. Normal annual repayments are covered by the depreciation allowance in the cost of service and consist of a minimum of 5% of the total funds advanced under Credit Agreement, or 75% of the cash flow generated from the sum of depreciation and deferred taxes less capital additions. The bank financing consists of a ten year term ending in 1989 but contemplates a refinancing with long-term debt, either through loan guarantees or institutional lenders once stable operational status is achieved. Obviously, if re-financing is not achieved before 1989, a substantial balloon may exist, which would be amortized over a five year period. Thus, the term could be extended to 1994 under certain circumstances.

If the project goes awry, the debt repayment is accelerated with the amount outstanding amortized over a five year period. A number of events may cause this to occur; for example, if completion of the plant does not occur prior to December 31, 1985, if construction is halted for a significant period of time, or certain typical and maybe not so typical events of default occur. In most of these cases, however, a period of time has been provided to permit corrective action to occur before the accelerated amortization begins. This was the primary modification required by the FERC staff in reviewing the agreement to make it comport with the FERC's order and practices. Essentially, the Commission wanted to be notified in the event of any problem and given sufficient time to consider the alternatives which may be available to avoid the associated charges to the gas consumers represented by the accelerated debt recovery.

The second and third tariff elements are the billing mechanisms designed to ensure an uninterrupted flow of funds from the ratepayers to the project for the expenses and other charges it incurs. The first of these is the cost of service tariff of Great Plains which provides for the recovery of all costs of operation, including costs of capital, independent of the amount of gas produced, and operates in a manner which is expected to generally eliminate revenue lags associated with traditional rate case proceedings and fixed rate tariffs. This type of tariff is essential for Great Plains because the cash flow is tied to a single plant, unlike a company with multiple projects and sources of revenues.

The second billing mechanism essential to the project is the purchase gas adjustment clauses of the pipeline companies. The contracts between Great Plains and the pipelines do not require the pipelines to pay the charges unless the pipelines are allowed by the FERC to pass-through the costs to their customers. That is, these are not "take-or-pay" contracts, although the pipelines do take the risk of not collecting from their customers. This billing mechanism is consistent with this project financing approach in that the sponsors are not guaranteeing the debt directly, or indirectly through the pipelines. Thus, it is essential that mechanisms allow for an uninterrupted flow of funds from customers, through the pipelines to Great Plains, and then to lenders.

The fourth element, rolled-in pricing, is a traditional practice in pricing gas supplies, although some opponents to large supplemental gas supply projects' continue to propose incremental pricing. Obviously, the key issue which rolled-in pricing resolves is the marketability of a product, which initially will be significantly more expensive than the cost of natural gas and oil. For a first of a kind project and where regulation prevents long-term, uninterruptible contracts, the uncertainty that would be created from an experimental marketing approach would have been an added risk that lenders would not be willing to take. The averaging of all gas sources favors synthetic gas production when it requires help initially, but will become a significant net benefit to the ratepayer relative to future gas prices over the life of the coal gasification project. This effect is more clearly demonstrated in the attached graph and table (Exhibit III).

The fifth element is a surcharge on the gas sales to the pipeline customers during the project's construction period to recover currently the carrying costs on funds invested in the project. The traditional utility treatment of these costs is to capitalize an allowance for funds used during construction (AFUDC) which is then recovered, with a return, over the life of the facility. Recovering the carying costs during construction through a surcharge to current gas customers is somewhat novel to the gas industry, but the concept is not new. Where circumstances warrant it, the FERC allows electric companies to include construction work in progress in rate base and some 24 states allow some form of construction work in progress in rate base. We believe its application is particularly appropriate for the Great Plains project since it has an unusually long construction period of almost four years compared to other gas projects such as pipelines (1-1-1/2 years). The length of this period only aggrevates the inherent financing problem of a capital intensive project. We estimate that the surcharge eliminates the need for an additional $400 million of additional financing.

More important in this instance, however, is that the surcharge which begins with the commencement of construction provides tangible assurance to the lenders that the tariff they are relying upon is indeed operative. Any problems which arise would be identified early and corrected before significant funds had been advanced, which would not be the case if the tariff became effective only after the facility was placed in service.

The last two tariff elements of the FERC order relate to the treatment of the sponsors' investment in the project. The first, a 13% rate of return on equity, represents a reduction from the 15% requested by the sponsors; both of which, however, sound strange in this period of unprecedented interest rates and are the products of a more orderly perception of the economy to which we will hopefully return.

The last item relates to an advance expression by the FERC of the ground rules under which the sponsors would be permitted to request recovery of their investment in the event of project failure. Recognizing this is a demonstration project, the sponsors had proposed to forego recovery of their investment only if failure occurred for cost overruns or technical problems deemed to be within their control. The Commission found this distinction to be vague and difficult to define. Instead, it decided that imprudently incurred expenditures would be disallowed.

This summarizes the key elements of the tariff Great Plains received from the FERC which would permit the project to commence construction. It is very important to underscore the basis upon which the FERC approved the Great Plains project and these essential elements to this financing approach. Of paramount importance was the finding that the project should be viewed as a demonstration project, but even further, that this demonstration was much broader than just technical and included RD&D questions involving governmental and regulatory approval and review processes, environmental impact, and economic feasibility. Because of this, the Commission ruled that the project merits special treatment accorded only to research and development projects; that is, treatment not available for conventional gas supply projects. The FERC indicated that its action was not a precedent for similar treatment of other large scale demonstration plants, or future coal gasification projects. In line with its order, the FERC also ordered the establishment of a Project Monitoring System to monitor the construction and operation of the plant, assist in audits of costs charged to ratepayers, disseminate information and, in general, keep the Commission informed on the progress of this project.

I believe you will find it somewhat amusing and paradoxical when I tell you that the source of the project's financibility, the FERC, represents the last remaining risk to be considered in developing the financing. What I am referring to is the risk of regulatory reversal. This arises since under existing law, the current FERC cannot legally bind a subsequent Commission from changing approved tariffs.

Briefly, this can occur in three types of situations. The first is that under Section 5 of the Natural Gas Act a future commission might find after an appropriate hearing is held, that the previously approved tariff was unlawful because it was unjust, unreasonable, unduly discriminatory or preferential. The second situation could arise as a result of a more general rulemaking procedure. For example, the abolition of the PGA or automatic pass-through of project costs at the pipeline level could be one such instance. Lastly, it is possible that the tariff could be affected by legislative or executive branch actions. An example of this might be the total deregulation of gas and abolishment of all tariff mechanisms.

Under all three of these possibilities the banks and sponsors after considerable negotiation agreed to share the risks in the following summary manner: As long as the sponsors are not prevented by law or by FERC from passing on charges for the gasification project, the sponsors must pay the charges. If the FERC, law, or executive action make it impossible to charge the sponsors' customers (distribution utilities) in any form, it is the bank's risk.

The banks' primary strategy for managing their risk is to rely upon the opportunity for an evidentiary hearing prior to any adverse finding occurring. To that end, the banks' have attempted to build a strong record to support their position of relying on the tariff during the proceedings before the FERC, and the FERC did indicate its recognition that the banks were relying on the FERC order.

Financing Plan - Loan Guarantees

At this writing, the first year loan guarantee application is only being evaluated, not awarded. Thus, the terms and conditions of any such guaranteed debt are unknown, although we do know that the Act and related regulations are extensive and quite specific.

As for the FERC order, full loan guarantees would mean a transfer of the abandonment risk for the debt from the ratepayer to the taxpayer.

Conclusion

This concludes an overview of the Great Plains project. The size of the project, its unique nature, the regulatory interplay, all contributed issues which required careful consideration and negotiation in developing a financing plan.

Great Plains Coal Gasification Project
Principal Parties

The Partners in Great Plains:

ANR Gasification Properties Company (ANR), a subsidiary of American Natural Resources Company

PGC Coal Gasification Company (PGC), a subsidiary of Peoples Energy Corporation

Columbia Coal Gasification Corporation, a subsidiary of Columbia Gas System, Inc.

Tenneco SNG, Inc., a subsidiary of Tenneco, Inc.

Transco Coal Gas Company, a subsidiary of Transco Companies, Inc.

The Pipeline Purchasers of Coal Gas:

Michigan Wisconsin Pipe Line Company, a subsidiary of American Natural Resources Company

Natural Gas Pipeline Company of America, a subsidiary of Peoples Energy Corporation

Columbia Gas Transmission Company, a subsidiary of Columbia Gas System, Inc.

Tennessee Gas Pipeline Company, a Division of Tenneco, Inc.

Transcontinental Gas Pipeline Corporation, a subsidiary of Transco Companies

The Project Administrator:

ANG Coal Gasification Company, a subsidiary of American Natural Resources Company

The Contractors:

Lummus Company

Kaiser Engineers,Inc.

Coal Supply:

The Coteau Properties Company, a subsidiary of North American Coal Corporation

Lenders:

A bank syndicate managed by three leading banks (Citibank, N.A., Morgan Guaranty Trust Company of New York, Bank of America N.T.&S.A.) and/or bonds backed by a Federal loan guarantee.

Power Supply and Purchaser of Coal Fines:

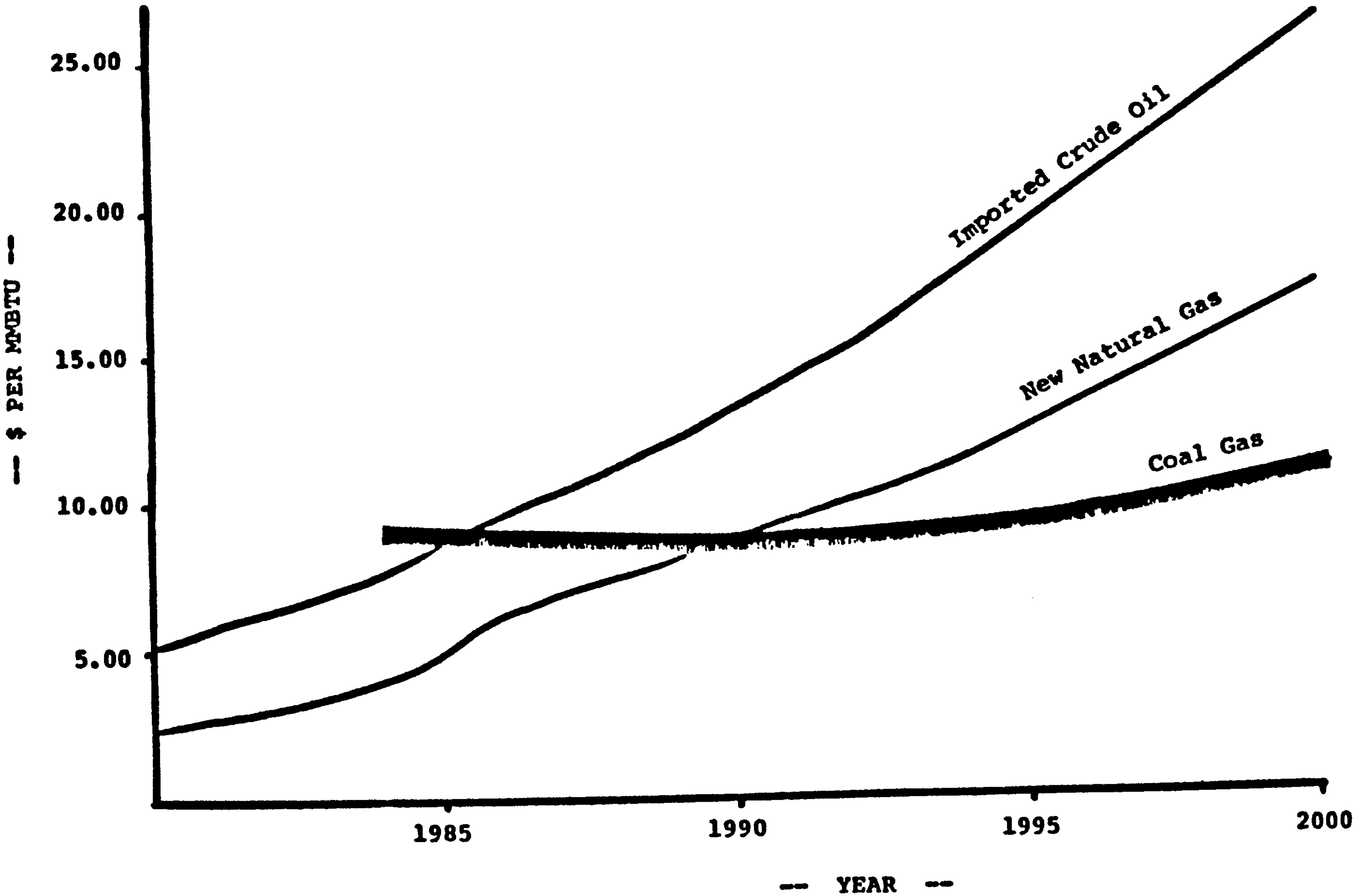
Basin Electric Cooperative Corporation, a North Dakota electric cooperative corporation

SUMMARY

Amount	$1,400,000,000
Borrower	Great Plains Finance Corporation, a wholly-owned single purpose subsidiary of Great Plains Gasification Associates, a North Dakota general partnership; each of its five equal Partners is a corporation affiliated with an interstate gas transmission company.
Use of Proceeds	To provide (i) up to 75% of the cost of constructing and testing the first commercial-sized plant designed to demonstrate the feasibility of producing high BTU synthetic natural gas from North Dakota lignite coal, and (ii) the capital costs of the related coal mine, other than the capital costs of such mine that are required to be provided by Basin Electric Power Cooperative which will obtain coal from such mine for use in the electric generating units it is constructing on a nearby site.
Source of Debt Service	Federal Energy Regulatory Commission approved tariffs of Great Plains and five interstate gas transmission companies, each of which is affiliated with a Partner. These tariffs permit amounts equal to all of Great Plains, cost and expenses, including debt service and after-tax return on equity, to be charged to the consumers served by such gas transmission companies. The payment of debt service and other costs and expenses of Great Plains is dependent upon the continued existence of these tariffs.
Availability Period	Until 365 days after the date the gasification plant is placed in-service, but not later than December 31, 1986.
Maturity	December 31, 1989, subject to extension to December 31, 1994, as described under "Alternate Amortization."
Amortization	Monthly repayments of principal are to commence (1) one year after the Plant is declared in-service, but (2) no later than January 31, 1987, in amounts not less than .416% times the aggregate borrowings outstanding at the termination of the availability period (which is equivalent to 5% per annum). On this basis, up to approximately 85% of the borrowings could be outstanding at December 31, 1989.

Prepayments	Optional prepayments may be made at any time without penalty of premium in minimum amounts of $24 million. Mandatory prepayments are to be made to the extent that 75% of depreciation and deferred taxes exceeds the sum of re-payments and certain permitted capital expenditures.
Alternate Amortization	In certain events, including borrowings being outstanding after December 31, 1989, the amortization schedule will be altered to provide for the remaining principal to be amortized monthly over a 60 month period. During periods of alternate amortization, the interest rate would be 2% over the applicable base interest rate (see "Credit Agreement - Events of Alternate Amortization").
Interest Rate	The higher of the fluctuating 90-day base rate of Citibank, N.A. or 1/2 of 1% above the three-week moving average interest rate payable on dealer placed 90 to 119 day commercial paper plus (i) 1% through June 30, 1981; (ii) 1-1/4% thereafter through June 30, 1982; (iii) 1-1/2% thereafter through June 30, 1983; (iv) 1-3/4% thereafter through June 30, 1989; (v) 2% thereafter until final repayment; payable monthly.
Commitment Fee	1/2 of 1% on the unused commitment; payable monthly.
Managing Banks	Citibank, N.A.; Morgan Guaranty Trust Company of New York; Bank of America N.T. & S.A.
Management Fee	After the initial borrowing each Managing Bank will have received $550,000.
Agent	Citibank, N.A.

COMPARISON OF CURRENT DOLLAR COSTS
OF COAL GAS TO OTHER FUELS



GREAT PLAINS GASIFICATION ASSOCIATES
COMPARISON OF CURRENT[1] DOLLAR COSTS
OF COAL GAS TO OTHER FUELS
($/MMBTU)

Line No.	Year (Col. 1)	Coal Gas[4] (Col. 2)	Natural Gas New Wellhead[2] 7% After 1990 (Col. 3)	Natural Gas New Wellhead[2] 8% After 1990 (Col. 4)	Imported Crude Oil[3] Escalated At 9.6% To 1990 7% After 1990 (Col. 5)	Imported Crude Oil[3] Escalated At 9.6% To 1990 8% After 1990 (Col. 6)
1	1984	$ 8.87	$ 3.89	$ 3.89	$ 7.79	$ 7.79
2	1985	8.83	5.00	5.00	8.53	8.53
3	1986	8.80	6.45	6.45	9.34	9.34
4	1987	8.74	6.95	6.95	10.22	10.22
5	1988	8.72	7.45	7.45	11.19	11.19
6	1989	8.73	8.10	8.10	12.26	12.26
7	1990	8.79	8.80	8.80	13.42	13.42
8	1991	8.85	9.42	9.50	14.36	14.49
9	1992	9.01	10.08	10.26	15.36	15.65
10	1993	9.19	10.78	11.09	16.44	16.91
11	1994	9.42	11.54	11.97	17.59	18.26
12	1995	9.70	12.34	12.93	18.82	19.72
13	1996	10.04	13.21	13.96	20.14	21.30
14	1997	10.44	14.13	15.08	21.55	23.00
15	1998	10.91	15.12	16.29	23.06	24.84
16	1999	11.43	16.18	17.59	24.67	26.83
17	2000	12.00	17.31	19.00	26.40	28.97
18	2001	12.61	18.52	20.52	28.25	31.29
19	2002	13.17	19.82	22.16	30.22	33.79
20	2003	13.70	21.21	23.93	32.34	36.50
21	2004	14.28	22.69	25.85	34.60	39.42
22	2005	14.90	24.28	27.92	37.03	42.57
23	2006	15.58	25.98	30.15	39.62	45.98
24	2007	16.31	27.80	32.56	42.39	49.64
25	2008	17.09	29.74	35.16	45.36	53.63

[1] GNP deflator for 1980-1984 estimated to average 7.4% annually; thereafter, inflation estimated to average 7% annually.

[2] New natural gas prices follow provisions of Natural Gas Policy Act which provide ceiling prices through 1985 equal to $1.75 at 04/20/77 plus GNP Deflator and incentive adjustment (i.e., 3.7% per year through 04/20/81 and 4.2% per year through 01/01/85). After 1985, new natural gas prices are set so that the resulting average end-use price of gas to industrial users is equal to the average price of No.6 oil.

[3] Import price of crude oil at 04/01/80 is approximately equal to $31.00 per barrel or $5.34 per MMBTU.

[4] The coal gas prices do not include any value for AFUDC, which is assumed to be recovered through a surcharge during the construction period. The inclusion of AFUDC would not materially change the cross-over point with other fuels or the price pattern for coal gas.

GREAT PLAINS GASIFICATION ASSOCIATES
COMPARISON OF CONSTANT DOLLAR COSTS OF COAL GAS TO OTHER FUELS
(Constant 1980 $/MMBTU)[1]

Year (Col. 1)	Coal Gas[3] (Col. 2)	Natural Gas New Wellhead[2] 0% After 1990 (Col. 3)	Natural Gas New Wellhead[2] 1% After 1990 (Col. 4)	Imported Crude Oil Escalated At 2.5% Thru 1990 0% After 1990 (Col. 5)	Imported Crude Oil Escalated At 2.5% Thru 1990 1% After 1990 (Col. 6)
1984	$ 6.67	$ 2.93	$ 2.93	$ 5.86	$ 5.86
1985	6.20	3.52	3.52	6.01	6.01
1986	5.78	4.24	4.24	6.14	6.14
1987	5.36	4.27	4.27	6.27	6.27
1988	5.00	4.28	4.28	6.43	6.43
1989	4.68	4.34	4.34	6.56	6.56
1990	4.40	4.41	4.41	6.71	6.71
1991	4.14	4.41	4.45	6.71	6.78
1992	3.94	4.41	4.50	6.71	6.84
1993	3.76	4.41	4.54	6.71	6.91
1994	3.60	4.41	4.59	6.71	6.98
1995	3.46	4.41	4.63	6.71	7.05
1996	3.35	4.41	4.68	6.71	7.12
1997	3.26	4.41	4.73	6.71	7.19
1998	3.18	4.41	4.78	6.71	7.27
1999	3.11	4.41	4.82	6.71	7.34
2000	3.06	4.41	4.87	6.71	7.41
2001	3.00	4.41	4.92	6.71	7.49
2002	2.93	4.41	4.97	6.71	7.56
2003	2.85	4.41	5.02	6.71	7.64
2004	2.77	4.41	5.07	6.71	7.71
2005	2.70	4.41	5.12	6.71	7.79
2006	2.64	4.41	5.17	6.71	7.87
2007	2.59	4.41	5.22	6.71	7.95
2008	2.53	4.41	5.28	6.71	8.03

[1] GNP deflator for 1980-1984 estimated to average 7.4% annually; thereafter, inflation estimated to average 7% annually.

[2] New natural gas prices follow provisions of Natural Gas Policy Act which provide ceiling prices through 1985 equal to $1.75 at 04/20/77 plus GNP Deflator and incentive adjustment (i.e., 3.7% per year through 04/20/81 and 4.2% per year through 01/01/85). After 1985, new natural gas prices are set so that the resulting average end-use price of gas to industrial users is equal to the average price of No.6 oil.

[3] The coal gas prices do not include any value for AFUDC, which is assumed to be recovered through a surcharge during the construction period. The inclusion of AFUDC would not materially change the cross-over point with other fuels or the price pattern for coal gas.

GREAT PLAINS GASIFICATION ASSOCIATES
PRESENT VALUE OF COST OF SUPPLYING
45 TRILLION BTU/YEAR FOR 1984-2008[1]
(In Millions of 1980 Dollars)

			Imported Oil			
Line No.	Year (Col. 1)	Coal Gas (Col. 2)	Escalated At 0% (Col. 3)	Escalated At 1.0% (Col. 4)	Escalated At 2.5% To 1990 & 0% Thereafter (Col. 5)	Escalated At 2.5% To 1990 & 1.0% Thereafter (Col. 6)
1	1980	$ 5.77	$ .00	$ .00	$ .00	$ .00
2	1981	52.88	.00	.00	.00	.00
3	1982	115.55	.00	.00	.00	.00
4	1983	128.33	.00	.00	.00	.00
5	1984	246.93	197.87	205.60	217.90	217.90
6	1985	218.60	188.45	197.69	212.58	212.58
7	1986	194.09	179.48	190.08	207.40	207.40
8	1987	171.42	170.93	182.77	202.34	202.34
9	1988	152.29	162.79	175.74	197.40	197.40
10	1989	135.75	155.04	168.98	192.59	192.59
11	1990	121.55	147.66	162.48	182.89	182.89
12	1991	108.93	140.63	156.24	174.18	175.86
13	1992	98.73	133.93	150.23	165.89	169.09
14	1993	89.73	127.55	144.45	157.99	162.59
15	1994	81.82	121.48	138.89	150.46	156.34
16	1995	74.89	115.69	133.55	143.30	150.32
17	1996	69.06	110.18	128.41	136.48	144.54
18	1997	64.00	104.94	123.48	129.98	138.98
19	1998	59.46	99.94	118.73	123.79	133.64
20	1999	55.38	95.18	114.16	117.89	128.50
21	2000	51.90	90.65	109.77	112.28	123.55
22	2001	48.46	86.33	105.55	106.93	118.80
23	2002	45.07	82.22	101.49	101.84	114.23
24	2003	41.75	78.31	97.58	96.99	109.84
25	2004	38.65	74.58	93.83	92.37	105.61
26	2005	35.88	71.03	90.22	87.97	101.55
27	2006	33.41	67.64	86.75	83.78	97.65
28	2007	31.22	64.42	83.42	79.79	93.89
29	2008	29.04	61.35	80.21	75.99	90.28
30	Total	$2,600.54	$2,928.27	$3,340.30	$3,551.00	$3,728.36
31	Present Value[2] ($/MMBTU)	$ 2.31	$ 2.60	$ 2.97	$ 3.16	$ 3.31
32	Even Annual[3] Payment ($/MMBTU)	$ 4.75	$ 5.34	$ 6.10	$ 6.48	$ 6.81

[1]Based upon a 5% discount rate per year. See Appendix A, Table 6 to Opinion No. 69 f methodology and FERC comparison based on 1979 dollars.
[2]Calculated by dividing total present value by cumulative total energy production of 1,125 trillion BTU's.
[3]Calculated by dividing total present value by present value of the cumulative total energy production resulting in 547.87 trillion BTU's.

CONOCO'S PROGRAM FOR PRODUCTION
OF
METHANOL FROM COAL

Jimmie R. Bowden

CONOCO'S PROGRAM FOR PRODUCTION OF METHANOL FROM COAL

Jimmie R. Bowden
President
Conoco Coal Development Company
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Stamford, Connecticut

Ladies and gentlemen, I come before you today as an unabashed, born-again methanolic. Unlike some, however, who have experienced flash-of-light conversion, I have proceeded to this state of grace slowly, perhaps even grudgingly over a period of years. It is, after all, difficult to abandon a posture of many years standing, even in the face of compelling logic.

In defense of my former position as a proponent of direct liquefaction of coal, I can say that even in retrospect, that was the way to go for many years based on the best technical knowledge and prediction and on the basis of the then accepted environmental climate.

In the middle '70's, however, things began to change. Predicted technical and economic advances in liquefaction techniques failed to materialize. Environmental concerns heightened at every step of the production, distribution and use cycle. And the slack time for making technological decisions relating to synthetic fuels production had collapsed to something near, or perhaps less than zero.

For Conoco, the use of commercially proven technology to make methanol from coal became the inevitable route of entry to synthetic fuels production.

Conoco is still developing its program for methanol production. Although frequently thought of as a major factor in a somewhat monopolistic industry, in reality, Conoco provides only about 2% of the liquid fuel consumed in the United States today. We plan, however, to have a significantly higher share of the methanol market. Our program is a long range strategic plan which will enable us to become a significant factor in the production, distribution, and sale of methanol primarily for fuel uses.

Our program recognized that elements other than technology and economics will contribute heavily to the success of our efforts and those of other synthetic fuels proponents. I'll touch on these briefly although this audience probably is more interested in the more traditional commercial aspects of planning.

And finally, our program is subject to revision. We are pragmatic, not dogmatic. We cannot control our destiny. We can influence our destiny by acknowledging the cosmic, political and social forces at work in today's world, by interpreting these forces and sensing changes in them, and by adjusting our program accordingly. That's what we plan to do.

In 1975, Conoco Coal Development Company made a speculative study of the technical and economic factors associated with the production of High Btu gas and a combination of High Btu gas and methanol from a Midwestern coal reserve owned by Consolidation Coal Company -- a sister company. The gasifier technology assumed was conventional dry bottom Lurgi. Although some of the conclusions of the study were somewhat surprising, notably the one that methane and methanol from a combined product slate plant should be priced equally on a Btu basis -- we didn't become overly excited.

Interest in developing a coal conversion project on the reserve waned, as the real cost of imported oil declined slightly. The full dimensions of the environmental movement had not yet emerged and besides, we then believed products of direct hydrogenation would be substantially cheaper and the technology soon would be demonstrated. So we returned to the back burner with the concept although many of us had our preconceptions shaken more than we realized.

Early in 1978, the Electric Power Research Institute acting in response to a DoE request asked us and others to evaluate a series of coal liquefaction processes, and to rank technical and economic factors, and recommend the best process for the country to bank on for early economic production. We have conducted research in coal liquefaction for about 30 years and maintained active surveillance of efforts carried out by others as well, so we felt highly qualified to respond.

Following extensive review of all our knowledge, we did comment on, and rank the suggested technologies but, somewhat, to our own surprise the only process we could recommend "banking on" was "none of the above". Our 1975 concept of co-product methane and methanol (indirect liquefaction) appeared far superior, and it was our recommendation that any serious production efforts in the near term be made on the basis of indirect liquefaction to produce methanol.

Instinctively we felt the time had come for Conoco to re-evaluate its synthetic fuels concepts and to prepare a commercialization program. The EPRI inquiry was the catalyst and we proceeded to plan to take our own advice.

Our preliminary assessment showed,

First, that refined products of equivalent quality could be made more cheaply than methanol from coal.

Second, that sentiment was mounting in Washington for some form of financial assistance to the fledgling synthetic fuel industry.

Third, that recognition of the environmental differences between use of products of indirect liquefaction and of direct liquefaction was emerging.

Fourth, that methanol was becoming recognized as a special case among indirect liquids, possessing unique advantages.

And lastly, that we had a fair amount of missionary work to do within our own company.

We predicted two long lead time items namely - the acceptance of the co-product concept and the development of a rational basis for providing incentives for synthetic fuel production by DoE and Congress. We therefore, made efforts in this arena our first priority.

After several informal discussions with senior DoE officials, we decided the best method of validating the co-production concept and the most effective method of developing a politically and economically appropriate incentive package would be a cost-shared study funded by a broad based industrial group and by the Office of Resource Applications of the DoE.

We prepared an unsolicited proposal covering this concept and submitted it on the first working day of 1979. We also solicited the industry cost sharing participants from among several potential producers, consumers and financial institutions. We developed detailed statements of work for the project and secured bids from qualified subcontractors. Following initial favorable response from DoE we rescoped and revised the proposal to incorporate DoE comments.

Unfortunately, during this time period, the Shah of Iran elected to take an extended foreign vacation and events began to overtake our proposal. The six-month period of validity of our proposal expired without official DoE action although I was advised informally near the end of the period that our proposal would not be accepted. Superficially, this element of our program failed, but I can't help but believe that our discussions with DoE in some small way have and will sensitize DoE to the technical and commercial promise of methanol made from coal.

For our part, we have revised, expanded and adopted the scope of work proposed to DoE and are using the Mark II and Mark III versions as the basis for the individual projects now being studied in our overall commercial program.

As we sensed eventual rejection of our proposal fairly early in the discussions, we decided a more direct approach to the financial incentives problem was required and prepared a series of non-site specific financial analyses designed to indicate the financial gap between:

(a) Foreign imports,

(b) the response of project economics to different types of incentives and,

(c) the financial effect to the government of different incentives policies which would be seen by companies like Conoco as equivalent.

These analyses were presented frequently during the third quarter of 1979 to senior members of Congress, DoE, OMB, etc. In general terms, this analysis which was based on first quarter 1979 conditions, indicated a "cost gap" of just under $12 per barrel at the reference point of 12% DCF return on 100% equity financing.

Four methods of closing the gap were analyzed:

1. Direct subsidy (purchase price guarantee).

2. Production tax credit (limited to $3.00 per bbl).

3. Additional investment tax credit.

4. Accelerated depreciation (Capital Cost Recovery Act of 1979).

Combined effectiveness to the government and to industry is in the inverse order listed. The three least effective of these four incentives now exist in enhanced form compared to the third quarter of 1979, and Congressional action on the most effective incentive may be forthcoming. As a point of interest, under the reference conditions studied, a $12 per barrel subsidy is equivalent to 34% additional investment tax credit, and the effect of five year accelerated depreciation according to the 10-5-3 bill is equal to $6 per barrel or 17% ATC.

During the course of discussion with congressional leadership, Conoco committed to the expenditure of substantial sums of money in an attempt to commercialize synthetic fuels technology should the "cost gap" be closed by congressional action in the preferred form of passage of the 10-5-3 bill, and extension and increase of the energy tax credit to 1991 and 25% respectively.

Although these events have not transpired, recent congressional action in the form of extension, though not expansion, of the Energy Tax Credit to 1990, together with prospects of some favorable action on the 10-5-3 bill and changed market conditions have encouraged us to start the time consuming but relatively inexpensive early phases of several methanol/methane projects. However, we have not yet made commitments to the tens of millions of dollars necessary for full engineering design, site acquisition, etc.

Our commercial program is based on four premises.

First, we believe Conoco's principal interest and main profit potential lies in liquid fuels; so we propose that Conoco take only the methanol from these co-production plants and sell, or upgrade and sell, methanol in our own channels.

Second, we believe there are significant profit opportunities in an efficient manufacturing and distribution network throughout the United States; so we see the full development of this concept requiring multiple plant locations sited across the country.

Third, the capital requirements for multiple plants are enormous; so we foresee, at least for the first few plants, joint venture arrangements with partners whose primary interests are in the gas produced in these plants.

Fourth, although present technology clearly favors co-production, technology probably will develop which will enable us to construct wholly-owned methanol-only plants, thus, simplifying our business relationships.

The prime target market for our methanol production is the power generating utility market. Here methanol has been demonstrated, in a joint EPRI - Southern California Edison Test Program, to be a fuel superior to either gas or distillate fuel for use in stationary gas turbines. Higher power output, lower emissions and lower maintenance are projected on the basis of three extensive tests conducted during 1979 in California.

At first, transportation uses will represent a secondary market for methanol, although we expect ultimately this will be the primary market. Uncertainty about the form of use of methanol and the difficulty of building a user fleet and delivery logistics system simultaneously with production capacity, have caused us to take the prudent course of relying on stationary fuel consumers for the establishment of the program. Later, we can try to enhance profits by increasing the percentage of sales to the transportation markets.

To begin our penetration of transportation markets, we supported a co-operation between the Mechanical Engineering Department of the University of Santa Clara, Alcohol Energy Systems, Inc., the Los Angeles County Engineering Department, the Ford Motor Company and Volkswagon of America in the presentation of proposals to the State of California for the conversion of three fleets of cars to alcohol fuel.

Fleet 1 will consist of 12 converted Ford Pinto car pool vehicles which are used by state employees. Fleet 2 will be composed of state-owned Volkswagen rabbits operating out of the Sacramento garage. And Fleet 3 will be county-owned cars operating in Southern California. The cars for Fleets 2 and 3 will be representative of 1985 technology. They will be required to meet 1982 emissions standards and to achieve fuel mileages equivalent to the 27.5 MPG required by Federal standards for 1985 (238 miles per million Btu).

Half of the cars in Fleets 1 and 2 will run on straight methanol and half on straight ethanol while all the cars in Fleet 3 will run on methanol. Initial developments to modify and obtain approval of engines have begun and full scale testing is expected early next year. The tests will run for approximately two years.

Methanol will be supplied both directly and through retail outlets by Douglas Oil Company, a Conoco subsidiary. Conoco Coal Development Company will maintain a liason both with the proposers and with the state in order to obtain maximum value from the tests. It is anticipated that sufficient information will be gained during the test program to make it possible for a substantial number of the captive fleets in California to convert to methanol when methanol appears on the market later in the 1980's.

Although some might prefer to wait for so-called second generation technology, we believe that presently proved technology using lignite and sub-bituminous coal for co-production of methanol and methane is excellent and nearly as good as it is going to get. We do not expect that any plant built before 1990 using today's processes will become economically obsolete during its projected lifetime.

On mid-western coal, present technology is adequate to marginal. Cost of operation, rather than plant operability, is the issue so a careful economic analysis will tell us whether or not to invest in this case. On the other hand, we simply are not satisfied with current processes which have demonstrated the ability to handle the highly caking eastern bituminous coals.

Therefore, although we now can implement our business concept on half or perhaps slightly more than half of the U.S. coal reserves, we cannot achieve our full potential unless an efficient gasifier for eastern coal is developed. Successful completion of the Joint Conoco/DoE Noble County, Ohio slagging gasifier demonstration plant program, therefore, is a key factor in our overall methanol commercial program as well as in the country's efforts to convert eastern coal to pipeline quality gas.

In order to execute this plan, we are now identifying and conducting preliminary in-house evaluations of from 6 to 12 projects meeting our general criteria. During 1980, we plan to select 3 or 4 projects worthy of further study and begin cost shared studies, each costing in the range of $1-2 million. One of the projects will be 100% Conoco to give us maximum flexibility in the early stages of project development.

Sometime in 1981, we will move to narrow the field to the two best projects and commence the preliminary engineering design phase. The costs of each preliminary design will be in the order of $10-15 million. In addition to design work, this phase would include site options, development of environmental baseline data, preliminary permit activity, etc.

Commitment to construction probably would not occur until the 1983 budget period, but might come earlier as a result of adverse international circumstances, or efforts of the U.S. government. Capital costs depend on project specific factors, as well as, timing and inflationary factors. Since the nominal size of the plants under study is 25,000 BPD crude oil equivalent, each project is in the billion dollar class. Conoco would propose to take a 25 to 50% financial interest in each project.

Possible coal reserve or plant site areas involved in these discussions include the Emery (Utah), Wildcat Creek (Wyoming), Bowman (North Dakota) and Mid-Western basin bituminous coal reserves. Also included are sites in Louisiana as well as the Ohio site of the second generation Gasification Demonstration Plant.

The following project description will clarify our evaluation methodology.

On January 29, CCDC agreed with Airco, Bechtel, Cities Service, PPG and United Gas Pipeline to a preliminary study budgeted at $1,500,000 and scheduled to be completed in one year. Site areas to be studied are Lake Charles (prime) and the Mississippi River area south of Baton Rouge (backup). Coal types to be considered are Illinois basin, western sub-bituminous and Texas/Louisiana lignite. Gasification processes to be studied are commercially proved as appropriate to the coal, and near proved such as the slagging gasifier and Texaco processes. The product of the study will be an economic evaluation of optimum coal, process and site combinations. Possible extensions of the original scope include acquisition of site options, start of environmental baseline data acquisition, and full scale coal trials.

The project is typical of the study projects to be developed during 1980. We subsequently developed a similar project in Emery County, Utah and intend to develop one, possibly two additional projects of approximately the same quality as this project by the end of the year.

The Utah project also is a co-product plant, but in this instance, the medium Btu gas will be methanated and the co-products will be pipeline quality gas and methanol. In addition to Conoco, the project sponsors are Mountain Fuel, Pacific Gas and Electric, and Southern California Edison. The gaseous product will be placed in the gas distribution system and used in Utah and California.

The Planning variables in this project are fewer than in the Louisiana case. Lurgi gasifiers have been selected, site areas, coal reserves and water sources have been identified, and the feasibility study will include site specific environmental assessment and the definition of a plan for the development of the water supply. A cost-sharing proposal covering this scope of work was submitted to DoE on April 25 in response to the Feasibility Study Grant provisions of PL 96-126. It is the intent of most, if not all, of the sponsors to proceed with the feasibility study regardless of DoE response. The proposal anticipated immediate expenditure of money by the sponsors on the early phases of the project and, in fact, work is now in progress.

We have not updated our economic studies for some time. In proceeding to develop a small group of site specific projects, we have implicitly decided that generic studies are of no further value on an absolute basis and we will wait for the site-specific economics which will begin to be available at the end of 1980. We are, however, doing some speculative analysis directed toward such questions as:

1. What is the optimum ratio of methanol to methane in a Lurgi plant?

2. What are the cost implications of providing ratio flexibility?

3. What are the cost implications of making different or multiple grades of methanol?

4. What are the economies of scale in various plant configurations?

To some extent, the answers to even these questions are site specific, but some general guidance can be obtained from generic studies.

For example, we no longer believe that a fair allocation of plant costs will result in methanol being produced at the same Btu cost as high Btu gas. This certainly is true as the maximum methanol/methane production ratio (without methane reforming) is approached, and may also be true at the optimum ratio as well. On the other hand in the range of plant sizes considered (to 250 MMCFD), costs of high Btu gas are reduced -- even if both products are assigned equal Btu costs -- as the additional amount of methanol produced increases plant size thereby providing economies of scale.

All supporting studies of this type continue to yield strong support to Conoco's overall program although occasionally they suggest slight changes in programs or indicate possible synergism with other Conoco projects.

For example, a potential weakness of the Conoco program might be reasoned to be lack of production of methanol until 1986 or 1987 at the earliest. However, in the middle '70's, Conoco and a Japanese company completed a feasibility study of converting off-shore gas into methanol using a barge mounted plant. Although that project did not proceed, as the gas reserve failed to live up to expectations, a new apparent discovery again raises the opportunity. If an appropriate reserve is delineated, and a floating methanol plant is authorized, product could be available by 1984 to facilitate the market penetration of Conoco's coal-based product.

No discussion of commercial production of synthetic fuels could be considered complete without some reference to the Energy Security Act of 1980.

While the Act is now law, it will be several months before the regulations interpreting and implementing it are issued, and many months before the United States Synthetic Fuels Corporation functions.

It should be obvious from the chronology given earlier that Conoco's plan for commercialization preceeded, and was developed independently of this specific piece of legislation. In our view, the Act, as well as the more neutral tax incentives, is an accelerating mechanism leading to synthetic fuel production a few years earlier than if pure market forces alone were present.

We believe this acceleration to be in the national interest. The Act should be judged by the following standards: In comparison with other forms of incentives (in our opinion, the key alternative forms are investment tax credit and accelerated depreciation) does the Act yield:

A. More rapid production of synthetic fuels.

B. More economical (combining subsidies with actual prices paid) production of synthetic fuels.

C. More useful production of synthetic fuels as judged by user satisfaction.

My cloudy crystal ball says these benefits are not likely to materialize.

As one recently experienced in government energy related programs, I can say categorically that never did the association with the federal government result in more rapid progress than would have occurred under any other financially equivalent situation.

If, however, the federal government chooses not to provide equivalent financial incentives, thus forcing industry to work through the Energy Security Act, it is possible that bureaucratic delay would be more than offset by financial incentives and there would be some acceleration over unaided market forces. Failure to provide an equivalent alternative path or the assumption that the Act is appropriate and sufficient is a great hazard inherent in the Act.

Our analyses indicate that all forms of financial assistance provided by the Act are deficient, as compared to tax incentives, to the extent that potential producers are capable of utilizing the incentives currently. This results from the different assessments of political risk, economic risk and time value of money between industry and the federal government.

The requirements of the Act that the United States Synthetic Fuel Corporation demonstrates "the widest diversity of feasible technologies" precludes choices made on the criterion of maximum user satisfaction. Although the solicitation, evaluation and project selection mechanisms are not now known, it seems inevitable that this methodology will further diminish the customer satisfaction criterion.

I wish I could have a more positive attitude toward the Act as I strongly support its stated objectives. Better alternatives are available to the federal government and I hope they will be enacted by Congress.

If not, the Act probably is better than nothing and from the perspective of the year 2000 will prove to have been a useful though very awkward method of encouraging synthetic fuels production.

Suffice it to say that its passage was not a crucial element in Conoco's plans, but as the Act is developed through regulation and implementation we may yet find that it has desirable and usable features.

Success of Conoco's coal-based methanol program is far from assured. Still, each completed study and nearly every world event emphasizes the need for synthetic fuels and we have little doubt that methanol will prove to be one of the few synthetic fuels America can "bank on".

We are backing our beliefs with money.

THE STATUS OF THE COOL WATER COAL GASIFICATION PROGRAM

Dr. L. T. Papay

THE STATUS OF THE COOL WATER COAL GASIFICATION PROGRAM

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Abstract

The Southern California Edison Company and Texaco Inc. announced formation of the Cool Water Coal Gasification Program on July 31, 1979. The Program is designed to demonstrate technical and economic feasibility of the Texaco Coal Gasification Process, one of the leading processes for producing a "clean" synthetic fuel from coal. This proposed joint venture has a capital cost estimate of approximately $300 million. It involves the design, construction and demonstration of an integrated 100 megawatt coal gasification/combined-cycle electric generating facility on the commercial scale of 1000 tons per day coal feed rate.

In addition to advancing the state-of-the-art, the Cool Water Program has unique features in its arrangements for program funding. Both technical and financial participation is being sought from a variety of industrial organizations which have the collective ability to commercially transfer proven hardware from the demonstration program to the competitive marketplace. Also, Program Participants have the opportunity to receive full recovery of their contributed funds by means of a "fuel processing fee" based on the actual amount of synthesis gas produced by the facility.

To date, approximately one-half of required funding has been identified. Efforts are continuing to obtain additional commitments from other prospective parties. California environmental permits are in place, engineering design work has commenced, and testing of the plant is expected to begin about the end of 1983.

This Program is expected to be a successful step toward eventual commercialization of large-scale coal conversion technology to supply fuel to future combined-cycle plants, a fuel to existing boilers, and a possible fuel for other advanced energy systems such as fuel cells.

Background

For the largest oil and gas-burning utility in the U.S., the energy crisis has made alternative fuel technology a necessary if not mandatory component of corporate strategy.

As one of the steps in the overall strategy, the Cool Water Program was initiated to achieve the following major objectives:

- The construction of an integrated coal gasification/combined-cycle electric generating facility on a commercial scale.

- The demonstration of the following:
  - compliance with environmental regulations
  - operational flexibility and reliability
  - coal feedstock flexibility
  - overall integrated systems controls under various operating conditions including start-up, turndown and load following
  - alternate plant or process components and load following
  - alternate plant or process components
- The establishment of operating, maintenance safety and training procedures.
- The development of precise economic data to facilitate scale-up criteria for utility commercialization.

The Cool Water Program, thus, began in a conceptual phase in 1977. In February 1978, the Southern California Edison Company and Texaco Inc. signed a letter of intent to perform feasibility studies and to finalize a base agreement. By August 1978, the preliminary design study was completed providing a capital cost estimate of $292 million for a 100 MW integrated coal gasification/combined-cycle electric generating facility. The Texaco/Edison Agreement was executed on July 31, 1979. By this agreement, Texaco and Edison each committed $25 million to the Program. On December 21, 1979, the California Energy Commission granted the necessary permit to construct and operate a plant at a 1,000 ton per day coal feedrate for a 7-year demonstration period at Edison's existing Cool Water Generating Station. In December, negotiations began with GE Company to become a Participant and to supply the combined-cycle unit.

In January 1980, Bechtel Power Corporation was selected from six major engineering firms as the prime engineer/ contractor for the Program. A Program office was subsequently opened in February, and the final engineering effort, Phase II, got underway in Houston.

EPRI executed an agreement on February 14, 1980, to commit $50 million to the Program, the largest, single project commitment in EPRI history.

In order that a number of companies can be financial participants in this demonstration program, the SEC is expected to approve an exemption of the Program from the definition of "public utility" under the Public Utility Holding Act of 1935.

Data is being submitted to the USEPA to comply with Prevention of

Significant Deterioration certification.

Program Description

The Program has been planned to incorporate five distinct phases as follows:

Phase I - Preliminary Engineering/Program Formulation (Feb 78 - Dec 80)

Phase II - Final Engineering including Vendor Engineering & Funding Commitment (Feb 80 - Jan 81)

Phase III - Procurement-Fabrication/Construction/Pre-demonstration Shakedown (Jan 81 - Apr 84)

Phase IV - Operation and Testing (Apr 84 - Oct 90)

Phase V - Completion/Salvage/Dismantling (Oct 90 - Oct 92)

The site selected for the integrated coal gasification/ combined-cycle plant is SCE's Cool Water Generating Station near Daggett, California, approximately halfway between Los Angeles and Las Vegas. This location offers sufficient land, railroad accessibility, and ample water resources to accommodate the plant and its support facilities. Sized on a coal feedrate of 1,000 tons per day, the physical plant facilities will include coal receiving, handling and preparation equipment, the entrained bed oxygen blown gasifier, an oxygen plant, synthesis gas coder, particulate scrubber, sulfur removal and recovery systems, a combined-cycle electrical generation unit consisting of a combustion turbine electric generator, waste heat steam generator and steam turbine electric generator, and other necessary support facilities.

Coal Handling

Coal from a selected mine in the Western United States will be delivered to the site by approximately eighty 9.1×10^4 kg. (100 ton) car unit trains weekly. The coal cars will be enclosed or the coal will be sprayed with a dust suppressant at point of shipment. A receiving yard at the Cool Water site will be designed to accommodate these trains where the coal will be systematically unloaded and conveyed to closed silos for storage. The coal will then be crushed and pulverized to the required size (see Block Flow Diagram, Fig. 1). It then will be slurried with water (approximately 60% coal) and pumped at a nominal rate of 9.10×10^5 kg. (1000 tons) per day of coal to a Texaco refractory-lined gasifier.

Coal Gasification

In the gasifier, the coal and water will be reacted with oxygen (in an exothermic reaction) at high temperature (1000 to 1550 K [2000 to 2800°F]) and high pressure (4.14×10^6 pascals [600 lb./sq. in. gauge]).

The synthesis gas produced consists primarily of hydrogen (H_2) and carbon monoxide (CO) with a specific heat of combustion of approximately 11.2×10^6 J/m^3 (300 Btu/SCF). Within the gasifier the coal ash will be melted into slag, quenched with water and removed for disposal in a pressurized lock-hopper system as glassy, gravel-like pellets. The synthesis gas produced will be cooled in heat exchangers. The steam produced will be combined with steam from the waste heat steam generator to drive the steam turbine, thereby recovering and utilizing much of the process waste heat.

Gas Clean-up

After cooling, the synthesis gas will pass through a wet scrubbing system to remove any remaining particulates and this system should also remove a significant amount of the ammonia formed in the gasification process. The efficiency of particulate removal is expected to exceed 99.9%.

Gaseous sulfur compounds, consisting primarily of hydrogen sulfide (H_2S) and carbonyl sulfide (COS) will be removed in a Solexol^R, Rectisol^R or equivalent type system. A catalytic process upstream of the sulfur removal system may be used to hydrolize the carbonyl sulfide to hydrogen sulfide to enhance the sulfur removal capabilities of these commercially available systems. A Claus^R type sulfur recovery system will receive a concentrated H_2S stream from Solexol^R or equivalent type system for conversion to elemental sulfur for disposal or sale. The design efficiency of the sulfur removal system will be 97%.

The synthesis gas from the sulfur removal system will then be regulated to approximately 2.07×10^6 pascals (300 lb./sq. in. gauge) and metered before being directed to the combined cycle power plant or other auxiliary equipment. A pressure surge drum in the synthesis gas pipeline will provide a balance to minor load variations in the coal gasification plant. Major positive excursions due to gas turbine load changes or other reasons will initiate the release of any excess gas to a flare system for disposal.

Combined-cycle

The demonstration plant will combine one combustion turbine generating unit of approximately 65 MW capacity, one heat recovery steam generator, and one steam turbine generating unit of approximately 50 MW capacity. The gas turbine will be designed to operate primarily on the synthesis gas. However, provisions may be made for firing the gas turbine with a stand-by fuel. A steam turbine will be operated on steam produced in the heat recovery steam generator and the synthesis gas cooler. This combination of equipment will yield a high overall efficiency of the integrated-electric generation system. After being cooled in the heat recovery steam generator, the combustion gases will be vented through approximately a 60 meter (200 ft.) stack.

Auxiliary Systems

Auxiliary support systems such as wet type cooling towers for plant cooling will be shared insofar as practicable between the gasification and combined-cycle systems. The electrical power from the plant will flow through its own switch yard to a tie-in to the Edison transmission/ distribution system. In addition, a synthesis gas pipeline and associated control equipment between the gasification plant and Cool Water Unit 1 Boiler will be installed for testing combustion characteristics of synthesis gas in a conventional oil/natural gas-fired boiler as well as overall plant operating flexibility.

While the amount of plant water used will be dependent on how much of the time the plant is operated, our preliminary estimates for water requirement is between 1.5×10^9 and 2.2×10^9 liters per year (390×10^6 and 590×10^6 gallons per year). The water will be supplied from existing ground wells.

Environmental Requirements

It is expected that the overall emissions from the demonstration plant will approach those for a similar combined-cycle unit fueled with natural gas and will be well within current standards. The "design" expected emissions will in all cases meet or be lower than those required by the South Eastern Desert Air Quality Management District's Rule 67 (for new sources) as follows:

Pollutant	Maximum Emission Per Rule 67	Expected Emission From Plant
NOx	63.6 kg./hr. (140 lb./hr.)	63.6 kg./hr. (140 lb./hr.)
SO_2	90.9 kg./hr. (200 lb./hr.)	15.4 kg./hr. (34 lb./hr.)
Particulate	4.5 kg./hr. (10 lb./hr.)	2.3 kg./hr. (5 lb./hr.)

Waste water will be directed towards existing evaporation ponds with impervious linings.

Funding Principles

The Texaco/Edison Agreement, which outlines the basic principles of financial relationships of parties, provides for the joint ownership of the plant. The Program is being funded by a broad variety of industrial and institutional "Participants" and "Sponsors" which are viewed as having the necessary abilities to fabricate, install or operate commercially proven gasification facilities in the near future. Each Participant will commit \$25 million to the Program agreeing to assume a proportionate share of all Program costs. Each Sponsor will agree to commit a minimum of \$5 million, but less than \$25 million to the Program, agreeing to assume a proportionate share of all Program costs up to the amount of their contribution. All Participants except EPRI will be subject to unlimited liability, and it is contemplated the Participants will indemnify Sponsors for liability incurred in excess of their contribution. Table 1 presents a breakdown of the capital cost estimate for the plant totaling $292 million.

A unique feature of this Program is that Participants, except Edison, will have the opportunity to recover all their contributed funds, less any tax credits, by means of a fuel processing fee defined in the Agreement. Sponsors will have the opportunity to recover one half of their contributed funds, less their available tax credits.

Other benefits accrue to the Participants and Sponsors. These benefits include:

- membership on Program Management Committees
- royalty credits for use of the TCGD with CCU
- roylaties from patent licenses*
- one coal test (at cost for Sponsors)
- training of engineers, technicians and operators*
- visit facilities
- program information
- publicized participation
- test of process, material, or equipment*

*Not for Sponsors

The method of recovery of contributed funds will be through a fuel processing fee which establishes a $/Btu rate for the synthetic fuel consumed by the combustion turbine. Steam raised in the syn-gas cooler will be taken into account. Sale of sulfur and other by-products will also be used to repay Participants and Sponsors. The estimated overall economics for the Program are shown in Table 2.

Figure 2 presents in a graphical format the capital recovery method. If Cool Water Program operates at an average capacity factor of 77%, then Participants and Sponsors would recover 100% of their contributed funds. If the capacity factor is greater than 77%, then the recovery would be faster, but never greater than 100%. At a capacity factor below 77%, the recovery would fall short of the total contributed funds.

Prospects for Commercialization

The Cool Water Program has been formulated to demonstrate a much needed technology. The companies and organizations who have made financial commitments to the Program represent diverse interests. Utilities, oil companies, an engineer/ constructor, a gas turbine supplier and other firms are bringing strong capabilities to the Program to move towards the achievement of its goals and objectives.

The commercialization of this technology will be greatly assisted by the types of entities already represented by the Program. Advantages of the Texaco Coal Gasification Process with its inherent mechanical simplicity, its environmental acceptability and its feedstock versatility should enable it to lead other current gasification processes into the marketplace.

The Texaco process is particularly suitable to an electrical power generation with rapid turndown flexibility and its capability of high pressure operations.

The Cool Water Program is a next step from the 13.6×10^3 kg per day (15 tpd) at Montebello Research Laboratories and the 136.4×10^3 kg per day (150 tpd) unit operated by Ruhrchemie near Oberhausen, Germany. TVA is expected to start up another 136.4×10^3 kg per day (150 tpd) unit later this year. The Cool Water Program is the commercial unit size gasifier at 9.1×10^5 kg per day (1,000 tpd), but for a commercial power plant a number of gasifier trains operating in parallel are envisioned.

Summary

With the strong commitment from a number of large energy companies, the success of this major technological demonstration at Cool Water is much more achievable. The environmental advantages of the Texaco Coal Gasification Process are strongly encouraging to the use of coal in California.

TABLE 1

PROGRAM COST ESTIMATE SUMMARY
(x 1000)

Description	Total
Coal receiving, storage and preparation	$ 24,000
Oxygen plant	29,000
Coal gasification	32,000
Sulfur removal/recovery	15,000
Steam, condensate and water	23,000
Power generation equipment	42,000
Supporting systems and facilities	23,000
Initial operation	10,000
Subtotal	$198,000
E-C engineering & management	30,000
Other program expenses	26,000
Allowance for exposures	38,000
Subtotal capital	$292,000

TABLE 2

ESTIMATED ECONOMICS

		Base Rate Costs(1) ($ millions)	Fuel Processing Fees(2) ($ millions)	Coal Expense(3) ($ millions)	Total Cost ($ millions)	KWH(4) Generated (10^6)
1984	1	6.291	25.370	9.820	41.481	303.6
1985	2	7.820	41.208	19.500	68.528	544.4
1986	3	8.744	46.132	24.680	79.556	633.4
1987	4	9.055	48.972	28.650	86.677	677.9
1988	5	8.679	50.214	31.540	90.433	688.1
1989	6	7.477	51.074	34.280	92.831	688.1
1990	7	7.004	39.059	27.920	73.983	516.0
		55.070	302.029	176.390	533.489	4,051.5

(1) SCE's $25 million commitment plus allowance for funds during construction

(2) sum of O&M costs plus capital recovery components

(3) estimated, SCE coal purchase

(4) estimated electricity production based on 92 MW (net)

Figure 1

BLOCK FLOW DIAGRAM FOR COOL WATER PROGRAM

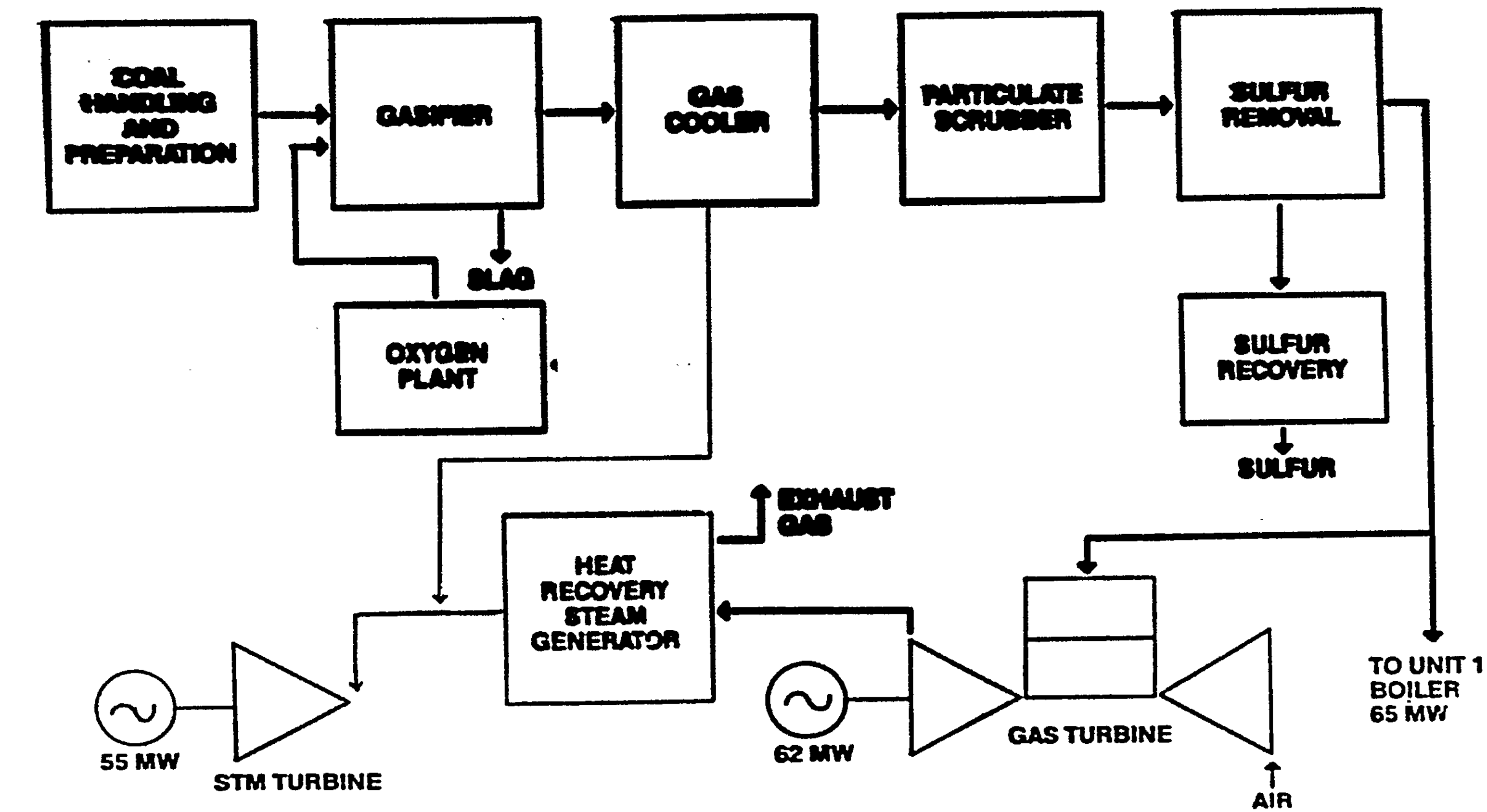
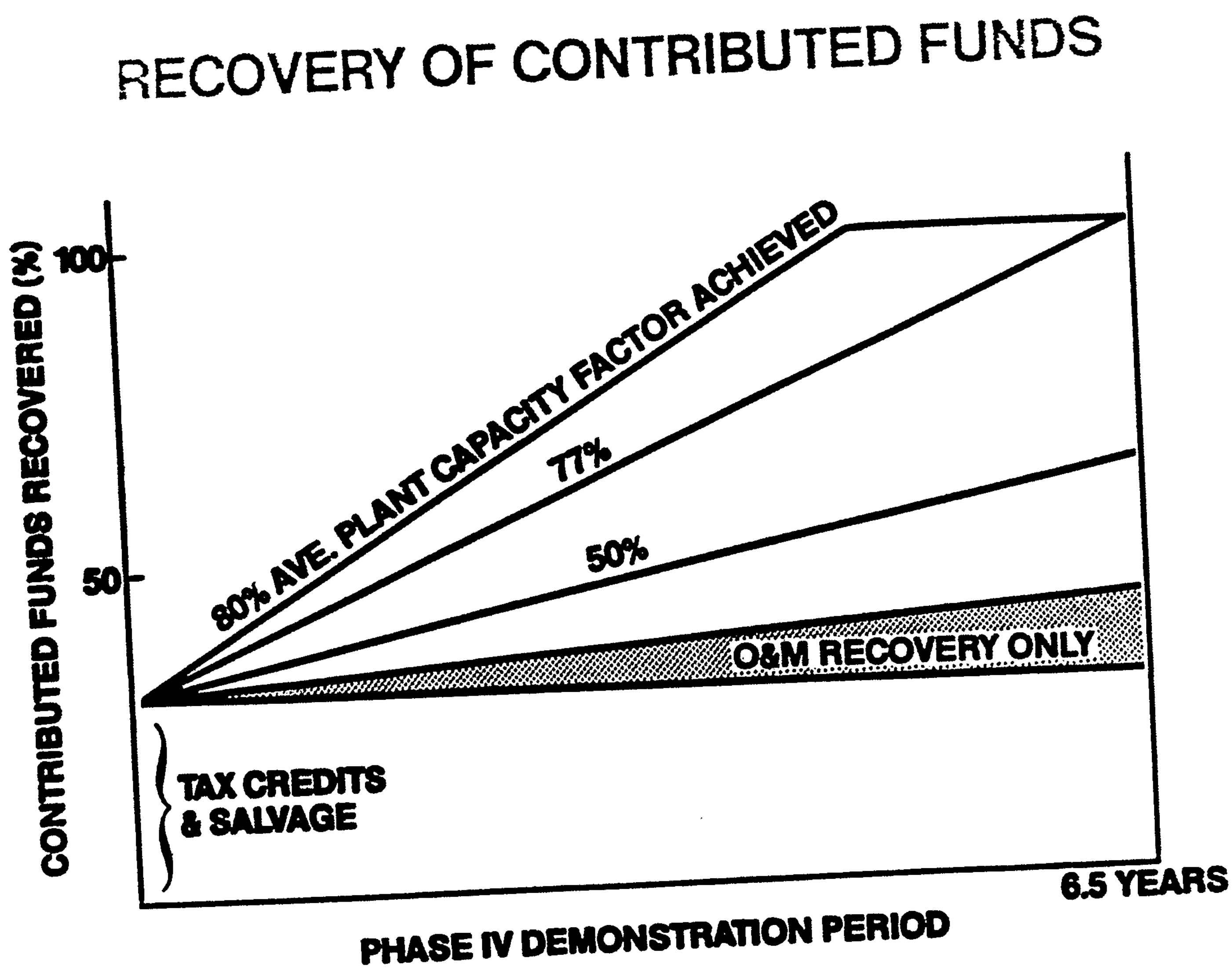


Figure 2


RECOVERY OF CONTRIBUTED FUNDS
CONTRIBUTED FUNDS RECOVERED (%)
100
50
80% AVE. PLANT CAPACITY FACTOR ACHIEVED
77%
50%
O&M RECOVERY ONLY
TAX CREDITS
& SALVAGE
6.5 YEARS
PHASE IV DEMONSTRATION PERIOD

ASPECTS OF COMMERCIAL MEDIUM BTU COAL GASIFICATION

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E. I. du Pont de Nemours & Co., Inc.
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Introduction

SLIDE 1 - ASPECTS OF COMMERCIAL MEDIUM BTU COAL GASIFICATION

When Dick Passman asked me to talk at this session, I hastened to point out that Du Pont has no announced specific project for the commercialization of Synfuels. As a result, I have no specific technology, project site, schedule or status to present to you. However, as Dick and a number of others here today know, we have been exploring commercial prospects for medium Btu coal gasification, particularly on the Gulf Coast for some time. We have also developed and presented our views on the issues and routes to Synfuels commercialization in forums such as this and in discussions with others in industry and government. Our actions may be best termed "precommercialization" ones but are a vital and little addressed phase in bringing Synfuels to commercial reality. I will focus on the aspects of this phase.

SLIDE 2 - TYPES OF COAL DERIVED GASES

Why medium Btu coal gasification? First, let's define medium Btu gas or MBG and contrast it with the other forms of coal gasification. High Btu gas is essentially methane, medium Btu gas is often called synthesis gas and is primarily a mixture of carbon monoxide and hydrogen with a heating value of about 300 to 350. Low Btu gas is air blown and is mainly nitrogen.

SLIDE 3 - MBG CHARACTERISTICS

In our view these characteristics of MBG make it more attractive than the other forms of coal gasification and among the most attractive of all Synfuels technologies. Combustion characteristics, and thermal efficiency make it a lowest cost alternative. MBG has environmental advantages over most other Synfuels and the direct combustion of coal. For those of us who use hydrogen and carbon monoxide, it has excellent feedstock characteristics.

SLIDE 4 - REGIONAL COAL GASIFICATION PLANT CONCEPT

The commercial concept we see as most attractive is depicted here where a large scale gasification plant pipelines the product to a concentrated industrial area for consumption by multiple users. We have been engaged in private studies of this concept with other industrial firms representing the types of uses shown on the slide and I wish to share with you some aspects of commercialization which have emerged.

SLIDE 5 - MBG FACILITY DESCRIPTION

To fully achieve the economy of scale inherent in coal conversion processes a very large facility is required. The energy output here is roughly 50,000 B/DoE. The coal supply requires large mines. Investment and operating costs exceed the assets of many responsible companies in the United States, as you well know. This is largely due to the extended chain of elements required to make up a viable commercial venture.

SLIDE 6 - ELEMENTS OF COMMERCIAL VENTURE

It is the integration of this sequence of elements, each one of which is a major project in its own right by normal standards, that is a major aspect of a commercialization effort. A number of different types of industries and capabilities are needed to build such a chain and deal with the scale of the undertaking. The appropriateness of a joint venture approach seems obvious. The talents of the mining industry, transportation industry - both for the coal and the product gas pipelining, an industry for gasification and, of course, the consumption by user industries and utilities must be melded together for success.

A very important aspect of the melding is participant characteristics.

SLIDE 7 - PARTICIPANT CHARACTERISTICS

A participant's view of their current and future energy position is highly significant. Some may feel secure with traditional supplies for many, many years, others are seeking an immediate start-up. Timing to match the ability to produce and consume within the period required for project implementation and the orderly phase out of current suppliers is essential and may vary widely. The views and requirements of regulated, regional organizations can differ substantially from private international corporations competing in world markets. The size of a participant is a common theme in this listing, particularly in the financial capability and end-use aspects. It will take some large firms to carry out such a venture, but smaller ones are likely to benefit most as a participant. The experience and capability characteristics shown here are required in each of the series of elements to assure a sound venture. The types of uses and demand patterns have a major impact on the choice of technology, operation and business arrangements. A venture by a group weak in any one of these areas is probably doomed to troubles. It appears a formidable task and it is, but groups with suitable characteristics and strengths can and do exist.

What then are the steps they take and the issues addressed?

SLIDE 8 - STEPS TO A COMMERCIAL VENTURE

Most discussions, literature and presentations deal with the right half of this slide. I wish to talk about the left half. Participants' objectives and needs that are compatible must first be worked out. The coal owner and miner must want to develop and exploit his resource. A company, willing to and capable of managing the construction and operation of gasification must synchronize its timing with the coal supplier as well as the pipelining element and users element schedules.

Properly synchronized timing is essential. Currently, the government mandate that electric utilities be off of or have taken significant steps to eliminate natural gas usage as a fuel by 1990 is acting to set a timeframe for this type of participant. The pending legislation on "oil backout" appears to preclude switching to that alternative. These factors indicate timing in the 1985 to 1990 range for electric utilities. However, currently there are no similar mandates for industrial users. This type of participant must see economic incentives for MBG attractive enough to commit his resources to such a conversion project in the same timeframe. In addition, resource holding participants must see such timing as adequate for converting their assets in the ground to a flowing revenue stream. Quite an integration job in this one aspect alone, wouldn't you say?

A satisfactory role for each participant must be defined commensurate with its resources and capabilities and the confidence of the other participants in its ability to execute. How will the mining be done? It could be by the resource company or another participant with mining capability or contracted out to a mine operator on a fee basis. Who will have prime responsibility for construction and operation of the gasification plant, who will pipeline the gas, who will be the users of how much? Is all product to be consumed by the participants or will a portion be marketed outside of the venture and, if so, who will handle the marketing and on what terms? These are just some of the issues to be resolved in defining agreeable roles.

Is the role of the participants to put up equity capital or will some simply provide a service at a fee or simply purchase product at a cost satisfactory to them and the venture.

Obviously, adequate resources - both people and financial - must be available and programmed into the time schedule with no gaps in the integrated venture. How is the manpower to be provided - from internal human resources of the participants or by external hiring? Addressing and resolving these many issues and questions to mutual satisfaction of all are vital steps to a commercialization. In themselves they constitute the crux of a commercial venture. This phase is what I have termed the "precommercialization" phase. Out of these efforts will come an integrated and defined venture. To accomplish these tasks, frank and open discussions of the objectives, strengths, weaknesses and decision criteria of each of the participants must be achieved or the venture cannot go forward and succeed. From our perspective this is a demanding and often time consuming series of steps, but is crucial to the development of massive Synfuels projects. The remaining and most often talked about phases - design, construction and operation are fairly routine once this "precommercialization" phase has been successfully completed.

Any one of these issues is not uncommon and as a matter of fact is routinely dealt with in business everyday. However, normally, it is simply between two companies at a single interface and on much smaller magnitude. One is buying and the other selling by reaching agreement on contractual terms and conditions. It is the series of steps or interfaces, the magnitude of the effort and the diverse interests and positions of a variety of participants that puts the challenge in a Synfuels venture.

SLIDE 9 - ASPECTS OF ORGANIZATIONAL STRUCTURE

Let me turn to some of the aspects where governmental and legal issues impact on the "precommercialization" steps. These begin to emerge as a venture group addresses its organizational structure. Some of the items listed on this slide - roles, capital sources, allocation of product and finances - have already been discussed but now there are the considerations of a partnership, corporation, possibly as a jointly held subsidiary, or some other mode of legal arrangement. Here, the existing organizational structure of participants will undoubtedly vary and the issue of joining regulated companies such as electric utilities and pipelines and private companies must be dealt with.

The aspect of limiting liability, of any one, or all, of the participants is both a legal and structural consideration. Probably the well publicized situation of the Great Plains gasification project is the best illustration of this point.

Current investment tax credits, depreciation and the possibility of increasing these as well as a production tax credit brings in the aspect of earnings and tax liabilities by the participants sufficient to fully realize these economic benefits. A totally separate, free standing venture organization without revenues in its early years cannot effectively utilize tax credits and as a result sees lowered venture returns.

As one might suspect, participants with common objectives, timing and perceptions of the future quite often can vie in the same market. This raises the anti-trust aspect for the venture. Of course, there are others.

SLIDE 10 - ASPECTS OF GOVERNMENTAL POLICY AND REGULATION

On these next two slides I briefly listed some of the other well known aspects of Governmental Policy and Regulation with which you are all familiar. This shows some environmental and supply ones. I don't plan to go into them.

SLIDE 11 - ASPECTS OF GOVERNMENTAL POLICY AND REGULATION (contd)

This shows some financial aspects. It will suffice to say that this laundry list impacts and causes uncertainties in even simple projects. The extended chain of elements and magnitude of a Commercial Medium Btu Coal Gasification Venture exponentially compounds the impact and susceptibility to adverse Government action. A problem for any one element automatically affects the others in the rather inflexible chain.

SLIDE 12 - CONCLUSIONS

In conclusion, to viably integrate the series of elements in such a venture requires willingness to understand the position of each other and take positive action either through compromises or imaginative solutions as impediments appear to achieve agreement among diverse industries.

The magnitude of the venture will strain almost any participant's resources and may in fact preclude a role for some organizations. The extended series of elements obviously makes the venture more vulnerable to changes and delay for any reason and, of course, magnifies the impact of government actions.

While the aspects of commercial medium Btu coal gasification I have discussed are myriad, complex and time consuming, I do believe that such ventures can and will be done.

Are there any questions?

FIGURE 1

Aspects of Commercial Medium BTU Coal Gasification

FIGURE 2

Types of Coal Derived Gases

High Btu Gas — Synthetic Natural Gas

Mainly Methane

Heating value about 1,000 Btu/Cu. Ft.

Medium Btu Gas — Synthesis Gas

Carbon Monoxide and Hydrogen

Heating value about 300-350 Btu/Cu. Ft.

Low Btu Gas — Fuel Gas

Carbon Monoxide/Hydrogen and mainly Nitrogen

Heating value about 90-120 Btu/Cu. Ft.

FIGURE 3

MBG Characteristics

- Equal to or Better than SNG for Fuel Use
- Increased Thermal Efficiency vs. SNG
- Reduced Cost-of-Manufacture vs. SNG
- Most Environmental Advantages
- Transportable up to 150-200 Miles vs. LBG
- Excellent Chemical Feedstock
- Unlikely to be Curtailed or Regulated

FIGURE 4

Regional Coal Gasification Plant Concept

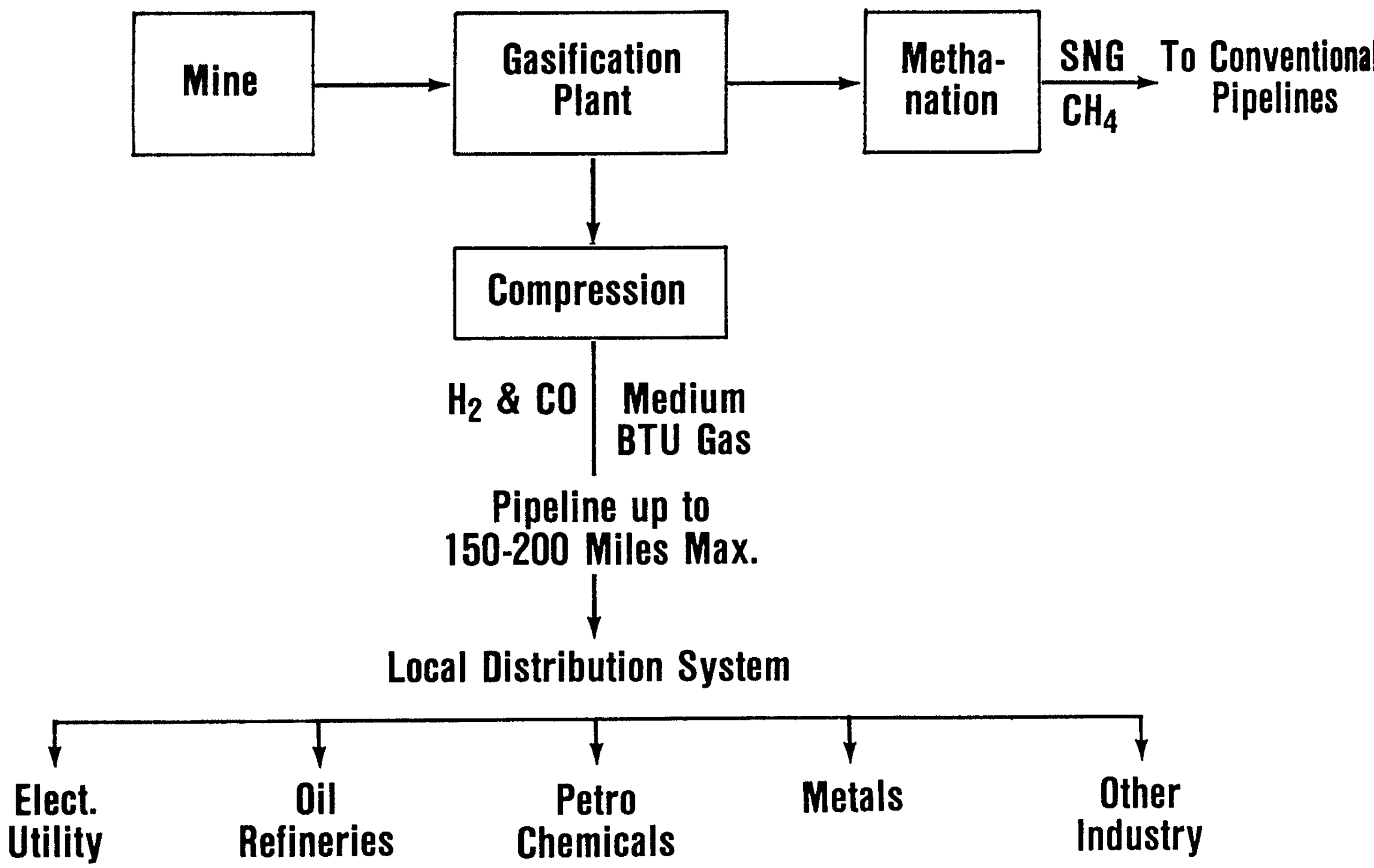

FIGURE 5

MBG Facility Description (1985-1990 Time Frame)

- Product ______________ 300 MMM Btu/Day of MBG
- Coal ______________ 10-15 MM Tons/Yr
- Investment ______________ $2-3MMM
- Operating Cost ______________ $600-800 MM/Yr

FIGURE 6

Elements of a Commercial Venture

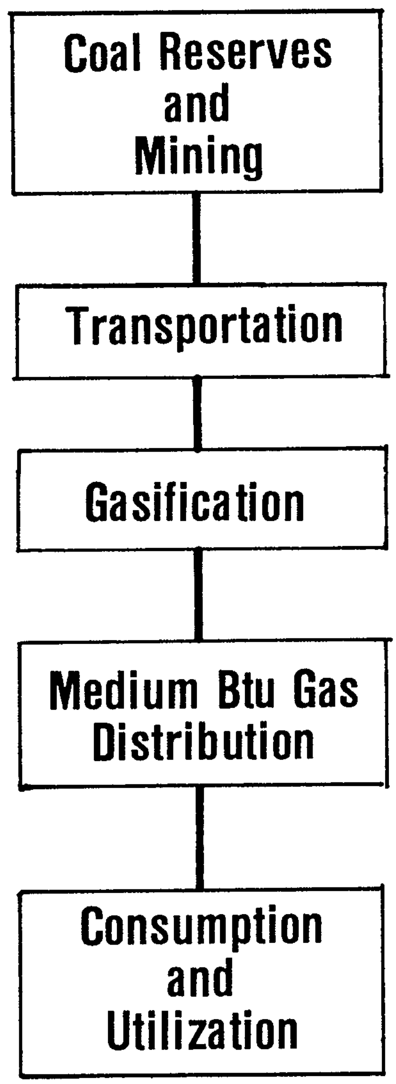

FIGURE 7

Participant Characteristics

- Energy Position
  - Current
  - Future
  - Timing
- Size
- Regulated — Private
- Regional — International
- Financial
  - Soundness
  - Capital Sources
  - Tax Liability
  - Decision Criteria
- Experience and Capability
  - Operating
  - Technical
  - Engineering
  - Large Projects
- Product Uses
  - Fuel and/or Feedstocks
  - Baseload and/or Peaking

FIGURE 8

Steps to a Commercial Venture

- Compatible Objectives and Needs
- Synchronous Timing
- Agreeable Roles
- Adequate Resources
- Feasibility
- Defined Venture
- Design
- Construction
- Operation

FIGURE 9

Aspects of Organizational Structure

- Partnership — Corporation — ?
- Participant's Roles
- Capital Sources
- Product and Financial Allocation
- Liability Limits
- Tax Pass Throughs
- Anti-Trust
- Others

FIGURE 10

Aspects of Governmental Policy and Regulation

Environmental

- Permitting Time
- Vulnerability to Delays
- Lack of Firmly Established Standards
- Health and Safety of Products

Supply

- Curtailment
- Mandated Fuel Type

FIGURE 11

Aspects of Governmental Policy and Regulation (cont'd.)

Financial

- Price Controls
- Transportation Cost Control
- Excise "Windfall" Profits Tax
- Capital Generation and Recovery
- Investment Tax Credit — 10% or 20%
- Synthetic Fuels Corporation Incentives
- Lack of "Front end" Incentives
- Development of Improved Technology