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COMMENTS ON

THE PANAMA COAL/METHANOL COMPLEX

Prepared for:

United States Trade and Development Prog
International Development Cooperation Agency
Washington, D. C. 20523
(Tel. 235-3660)

Prepared by:

Checchi and Company
Suite 910
1730 Rhode Island Avenue, N. W.
Washington, D. C. 20036
(Tel. 452-9700)

May 15, 1982

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CHECCHI AND COMPANY
1730 RHODE ISLAND AVENUE, N. W.
WASHINGTON, D. C. 20036

TELEPHONE
202 452-9700

CABLE ADDRESS
"CHECCHI"
TELEX 440157

May 15, 1982

Mr. Joe J. Sconce
Assistant Director
Latin America and the Caribbean
United States Trade and Development Program
International Development Cooperation Agency
Washington, D. C. 20523

Dear Mr. Sconce:

We are attaching our comments on the proposed Panama Coal/Methanol Complex as requested in Work Order No. 6 (under IQC AID/SOD/PDC-C-0399).

The Work Order specified that we comment on 7 specific topics, and our report is therefore organized under headings based on those topics.

To prepare this report, we met for a full day (May 3) with the staff of Ebasco Services Inc. in New York City, and then consulted with numerous private firms and Government agencies including the General Electric Company, manufacturers of "Combined Cycle" generators; Chem Systems, Inc., synthetic fuel experts; Fluor Engineers and Constructors, Inc., coal-fired generator specialists; Data Resources, Inc., fuel specialists; Pote[illegible]d Partners, bul[illegible] transport specialists ; the editors of Coal Week, Coal Outlook and Alcohol Week, Pacific Projects, Ltd. in Tokyo, specialists in bulk transportation and Japanese utilities; the Coal Task Force of the Department of Commerce, the Office of the U.S. Trade Representative, and the Department of Energy.

We have appreciated this opportunity to serve the U.S. Trade and Development Program.

Sincerely yours,

Frank L. Turner

Frank L. Turner
Vice President

Attached: Comments on Panama Coal/Methanol Complex

INTRODUCTION AND SUMMARY

1.0 Introduction

This report, prepared for the Trade and Development Program (TDP), comments on a proposal from Ebasco Services, Inc. (hereafter "Ebasco") of New York City. Ebasco is a diversified engineering firm noted, since the 1890's, for designing large-scale energy-related projects.

The TDP has requested Checchi and Company to make comments on a project proposed by Ebasco to produce fuel methanol in Panama from U.S. coal. Our comments on the project constitute a preliminary step in helping TDP to reach a decision to finance, or not to finance, certain costs necessary to prepare a feasibility study being requested by Ebasco.

Such a study would cost about $10 million, of which a small portion would be financed by TDP if TDP decides to proceed. The residual costs, under current Ebasco planning, would be financed by a private industry consortium of firms in such countries as the U.S., U.K. and Japan.

If the feasibility study of the project reaches a favorable conclusion, the next step would be for Ebasco to mobilize investment capital, amounting to $4.5 billion, to finance completion of the project in Panama by 1990.

The main objective of the project is to provide the Japanese electric power companies with a clean, competitively priced fuel needed to help meet Japanese energy requirements in 1990 and beyond. These total Japanese requirements will be the equivalent of 3,711 million barrels per year in 1990, rising at three percent annually to 4,843 million per year in 2000, according to official Japanese planning announced in April 1982.

2.0 Summary of this Report

2.1 Forecast of Japan's Energy and Methanol Needs

Japan's yearly energy requirements are rising as follows, according to official plans announced in April 1982:

	Kiloters of Crude Oil Equivalent Per Year	Converted to Barrels Per Year
1980	429 million	2,698 million
1990	590 million	3,711 million
2000	770 million	4,843 million
Annual Average Growth 1980 - 2000	3%	3%

Of the total Japanese requirements, 15 million kiloliters of crude equivalent in 1990 and 65 million kiloliters in 2000 will be met by what the Japanese call, "new fuels and energy." This category consists of energy derived from: (1) methanol, (2) ethanol, (3) oil sands and shale, (4) coal liquefaction, and (5) solar energy.

This report estimates that by 1993, one year after the proposed Ebasco project is on full stream, the Japanese power companies will need methanol in volumes that are larger than the output of the proposed project by 1.7 times. The Japanese methanol requirement will then probably continue to rise about four-fold from 1993 to 2000.

2.2 Concept of the Ebasco Proposed Project

The proposed project involves: (a) the opening or reactivation of high-sulfur coal mines in the midwest, chiefly in Illinois; (b) barging 20,000 tons per day down the inland waterway network to Gulf ports, probably Mobile or New Orleans; (c) shipping of coal by

towed, ocean-going barges to the Caribbean side of the Panamanian Isthmus; (d) gasifying the coal near the coal discharge point; (d) converting the coal gas to 12,000 short tons of methanol per day; (f) pumping the methanol by pipeline to the Pacific side; (g) loading methanol on bulk carriers destined for Japan, and later for Korea and Taiwan, under long-term contracts similar to those whereby Japanese utilities are now procuring crude oil, residual fuel oil, LNG, LPG, and coal.

2.3 Questions About the Project

In deciding whether or not to partially support a $10.0 million feasibility study of this project, questions have arisen within the U.S. Government agencies and elsewhere. Some of the major questions are addressed in this summary and more detail is provided in the report which follows:

2.3.1 Does Japan Offer a Market for Methanol?

As cited, official Japanese planning contemplates the use of methanol as a fuel in significant volumes rising rapidly from 1990 to 2000 to a volume many times the output of the proposed Panama plant. This anticipated Japanese demand, supported by the opinion of reputable U.S. energy analysts, is probable because:

(a) Japan is continuing its quest for a clean, competitive fuel such as methanol.

(b) The switch to coal and away from oil since 1973 has created costly problems in Japan of air pollution control and solid waste disposal.

(c) The switch from oil and coal to LNG in the 1970's gave Japan's utilities a clean, competitive fuel, but supplies of LNG are finite; gasification and liquefication plants are costly (billions of dollars); and the price of LNG will soon rise in sympathy with U.S. deregulation.

(d) In November 1981, the leading Japanese utility (Tokyo Power) placed the first of eight or more orders for "Combined-cycle" generating plants. The first order was for two, 1,000 megawatt plants costing $800 million. For the first time, Japan has adopted a generating technology that allows for the economical use of methanol.

2.3.2 Will Methanol be Competitive?

We have analyzed the cost of using alternative fuels available to the Japanese power industry, using the "present value" method of discounting future costs. We have found the following comparison of 1981 costs for producing one kilowatt-hour of electric power from four different fuels used in Japan:

	LNG	Fuel Oil	Coal	Methanol
Cost in U.S. Mils to produce 1 kwh of electricity	81.5	104.9	104.0	94.1

In terms of 1981 pricing, the cost of methanol, as shown above, is not competitive with LNG. However, the proposed project in Panama will not go on stream until 1992, by which time we (and the energy industries) expect world LNG prices will move up in sympathy with U.S. deregulated gas prices and will continue to rise at a pace several percentage points annually above the escalation of oil prices, and well above the price escalation of coal -- the feed stock for methanol.

The coal feed stock for the proposed Panama project is Mississippi Valley high-sulfur coal. This coal will remain in the ground, unwanted, until such time as the U.S. supply of superior, more competitive coals begins to diminish -- many decades hence.

We see no reason to dispute Ebasco's estimates that this coal has a 1981 cost of $43.32 per ton delivered to Panama. This cost is well below the cost of other steam coals moving in foreign trade, for

example, Western U.S. coals are moving to Japan at more than $70 per short ton. Chinese low ash coals moved to Japan in 1981 at $51.36 per short ton.

Because of their unacceptability in the U.S. and thanks to the low-cost inland waterway transport, midwest coals are one of the world's cheapest forms of energy.

2.3.3 Why Not Produce Methanol in the Midwest Rather Than Panama?

For large-scale industrial projects in the U.S., it takes at least 43 months to obtain approvals from Federal regulatory agencies (more time is required if state and local approvals are included in the calculation). This means that the capital requirement for an industrial project will rise by more than one-third from the concept stage to operating reality.

In Panama, the plant can be started once the feasibility study confirms the economics, provided, however, the operators of the project guarantee compliance with U.S. pollution standards or better. The Panamanian willingness to proceed on this basis has been confirmed in writing to Ebasco by the President of Panama.

2.3.4 Are There Major Technical and Management Problems That Would Frustrate the Panama Project?

There are a range of problems, but they have been solved elsewhere. Included among such problems is pipeline transportation of methanol over a 4,000-foot ridge separating the Atlantic and Pacific sides of the Isthmus. Morrison-Knudsen are now completing a pipeline along the same route, and by October 1982, will be pumping Alaskan crude oil from the Pacific to the Atlantic over the same 4,000-foot ridge.

2.3.5 Is there Too Much Risk?

The methanol project involves a package of technologies that have been proven historically and in several parts of the world.

By comparison, with the technologies begun in the latter 1960's to develop liquefied gas (LNG) as a major fuel for Japan, the coal-to-methanol route, also for providing fuel to Japan, will be much simpler. In the case of LNG, it is necessary to (a) freeze gas to temperatures of -260° F (-162° C); (b) to build 200,000 to 500,000 DWT tankers equipped with cryogenic steel bulkheads; and (c) to regasify the LNG at the export destination. In the early 1960's, this concept, adopted on a large scale, was at first considered "far out," but now has become routine in supplying Japan with LNG energy from Brunei, Indonesia, and Abu Dabi (Bechtel of San Francisco, California, was the principal construction firm involved in this work).

We are quite sure the coal-to-methanol procedure will be much simpler and soon will be less expensive than natural gas liquifaction and regasification.

2.3.6 Conclusion

Panama and the Mississippi Valley states will benefit from the proposed Ebasco project, and the U.S. will export coals worth $9.0 billion (otherwise useless) over the 30-year project life.

METHANOL CHARACTERISTICS

1. Methanol (sometimes called methy alcohol) is a colorless, poisonou liquid; the composition is CH_3OH. - It is now largely produced from synthesis gas, from either methane or coal gas.

2. At different temperatures, BTU changes, but normal condition is:

   At 68° F, in liquid fuel form, methanol contains 56,560 BTU/gallon, or 8,570 BTU/lb.

3. When methanol is valued at the equivalent of solid fuel, it ranges from 8,570 BTU/lb. to 9,750 BUT/lb.

4. The specific gravity of methanol @ 60° F is 0.796.

5. Weight of methanol is 6.60 lbs./gal. @ 60° F.

Source: DOE, Bartlesville Technology Center, Bartlesville, Oklahoma, and Materials Handbook, Third Edition, by George S. Brady.

TOPIC 1

"The assumption that Japan will import substantial quantities of methanol in the future as part of total imports of liquid hydrocarbons. (Compare with the imports of steam coal from Western U.S., Colombia, and China.)"

1.1 Japan's Problem of Energy Security

Japan has experienced two traumatic threats to its oil supply; the first occurred in December 1973 when the OPEC countries stopped the export of crude; the second threat occurred in August 1979 when the hostage crisis interrupted the flow of oil to Japan from Iran.

[illegible] ises led Japan to switch from oil to coal at an accelerated pace. Table 1-A, showing Japan's official energy forecast, indicates the following decline in oil use and corresponding increases in coal and in the use of other forms of energy. Units in the tabulation are percentages of total energy derived from each fuel source named:

Year	Energy Derived from Oil	Energy Derived from Coal	Energy Derived from Other Sources	Total
1980	66.4%	16.7%	16.9%	100%
1990	49.1%	19.5%	31.4%	100%
2000	38.0%	19.0%	43.0%	100%

1.2 A significant point in the above tabulation is Japan's switch to fuels other than oil and coal. At present, coal is still "in," but coal is posing an increasingly severe problem in Japan because of (a) the accumulation of solid waste material in a country where land is scarce, and (b) the high cost of "scrubbing" emissions to remove sulfur dioxide and nitrous oxide. Therefore, in the long run, the trend is toward less pollutant fuels including methanol.

1.2.1 Evidence of Japan's Need for Methanol

Some evidence of Japan's need is summarized below:

Japan's Official Planning

Japan's official plans (Ministry of International Trade and Industry, General Energy Council) show the projected energy balance to 2000 (see Table 1-A). One component of the energy supply is entitled, "New Fuels and Energy," in the fifth line up from the bottom of Table 1-A. In terms of crude equivalent, the new fuels and energy are expected to rise as follows:

Year	Equivalent in Millions of Kiloliters	Equivalent in Millions of Barrels/Year
1980	0.7	4.4
1990	15.0	94.3
2000	65.0	408.2*

The term, new fuels and energy, in Japanese usage means five different sources of energy as follows:

(1) Methanol, 12.7%
(2) Ethanol, 5.0%
(3) Coal Liquefaction, 68.1%
(4) Solar Energy, 12.4%
(5) Oil Sands, Oil Shale, 1.8%
Total, 100%

The percentages shown above are based on an August 1979 Japanese official forecast by the same agency which authored Table 1-A. The 1979 forecast has now been replaced by the April 1982 forecast shown in Table 1-A. If the 1979 percentages shown above remain valid, the methanol component would be the equivalent of 116.7 trillion BTU in 1993,

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* To put these figures in perspective, Japan consumed 4.9 million barrels per day of petroleum products in 1980 as compared with the recent year U.S. consumption of about 16-18 million barrels per day or 6.0 billion barrels per year.

Table 1-A

LONG-TERM ENERGY SUPPLY AND DEMAND OUTLOOK FOR JAPAN
(Units are crude equivalent, expressed in millions of kilolliters; percentage of total in parentheses)

	FY 1980		FY 1990		FY 2000	
Demand (mil. Kl)						
All industries	253	(61.7)	329	(58.5)	--	
Energy-intensive industries	114	(27.9)	133	(23.7)	--	
Transportation	65	(15.8)	86	(15.2)	--	
Other uses	92	(22.5)	148	(23.3)	--	
Total	410	(100.0)	563	(100.0)	--	
Total energy demand (incl. supplier's loss)	429		590		770	
Supply						
Coal	92.4	(16.7)	153	(19.5)	200	(19.0)
Domestic	18.1		18.20		--	
Steam coal	21.3		66		--	
Nuclear power	15.7	(5.0)	46	(11.3)	90	(18.0)
Natural gas	25.9	(6.0)	68	(11.5)	82	(11.0)
LPG	16.8		43		--	
Hydropower	19	(5.6)	23.5	(5.0)	30	(5.0)
Pump-storage power	10.8		22		33	
Geothermal power	0.3	(0.1)	6	(1.0)	15	(2.0)
New fuel oils & energy*	0.7	(0.2)	15	(2.5)	65	(8.0)
Petroleum	285	(66.4)	290	(49.1)	290	(38.0)
Domestic	0.5		1.9		--	
LPG	14		24		--	
Total	429	(100.0)	590	(100.0)	770	(100.0)

Source: General Energy Council, MITI, via Japan Economic Journal, April 27, 1982.

* Defined as (1) ethanol, (2) solar energy, (3) methanol, (4) coal liquefaction, (5) oil sands and oil shale.

a year when the Panama plant would be in full operation. (The calculation is 919.1 trillion BTU x 12.7% - see 1993 column in Table 1-B.)

The output of the proposed Panama coal/methanol plant in 1993 would be the equivalent of 3.96 million short tons of methanol annually which would have a heat value of 67.87 trillion BTU, or 58% of the suggested requirement for Japan in 1993 (116.7 trillion BTU/67.87 trillion BTU = 58%). In short, the potential methanol demand in Japan by 1993 could be about 1.7 times the capacity of the Panama coal/methanol plant.

Other Forecasts of Japanese Methanol Requirements

The specialized consulting firm of Chem Systems, Inc. (Tarrytown, New York) forecasts that Japanese consumption of fuel methanol will rise to 300-600 million gallons by 1990, or the equivalent of 25.45 trillion BTU and could then go on to rise to 283 trillion by 2000; see Table 1-C.

1.3 The Switch to New Power Generation Technologies -- The Combined Cycle Plant

Starting in the 1960s, where rapid load growth was a problem for some U.S. utilities, a new type of generating technology became popular. This technology, developed principally by General Electric and Westinghouse is called the "combined-cycle" power system (see Annex A).

The combined-cycle plants (hereafter CCPs) have also become popular in Canada, Australia, the USSR, and the Middle East. The reasons for this popularity include the following:

Versatility in the Use of Fuels

The CCPs can use several types of fuel, such as natural gas, regassified LNG, fuel oil No. 2 (usually as a back-up), and methanol.

Atmospheric Emissions

When coal began to be used after the 1973 oil crisis, the contrast between noxious atmospheric emissions from (a) CCPs and (b) coal-fired plants

(Note: Report narrative continues after Tables 1-B and 1-C.)

Table 1-B

COMPARISON OF PANAMA COAL METHANOL PLANT OUTPUT
WITH JAPANESE DEMAND FOR NEW FUELS
1980, 1990, 1993, 2000

		1985	1990	1993	2000
A.	Japan's demand for "new fuels" (10^6 Kl of crude equivalent)	0.7 million per year	15.0 million	23.4 million	65 million
B.	Converted to BTU millions--1 Kl of crude = 39.3 million BTU (1 liter = 39,278 BTU)	27.5 tillion BTU per year	589.17[a/] trillion BTU	919.1[a/] trillion BTU	2,553.1[a/] trillion BTU
C.	Annual output in 1990 to 2000 of Panama plant (12,000 short tons of methanol/day x 330 days at 100% capacity)	--	1.98 million ST per year half capacity	3.96 million ST full capacity	3.96 million ST full capacity
D.	Panama plant methanol output converted to BTU (17.14 million BTU per short ton x 3.96 million tons)	--	33.9 trillion BTU per year (50% of capacity)	67.87 trillion BTU (100% of capacity)	67.87 trillion BTU (100% of capacity
E.	Output of Panama plant as a percent of Japan's demand for "new fuels," D/B	--	5.8%	7.4%	2.7%

a/ In 1990, the Japanese methanol requirement could be about twice the output of the Panama plant. The calculation is: 589.17 trillion BTU of required "new fuels" x 12.7% = 74.8 trillion BTU of methanol required which is 2.2 times the 33.93 trillion BTU of methanol output of the Panama plant in 1990.

In 1993, the Japanese methanol requirement could be about 1.7 times the output of the Panama plant. The calculation is: 919.1 trillion BTU of "new fuels" x 12.7% = 116.7 trillion BTU which is 1.7 times the 67.87 trillion BTU of output of the Panama plant in 1993.

In 2000, the Japanese methanol requirement could be nearly five times the output of the Panama plant. The calculation is: 2553.1 trillion BTU of "new fuels" x 12.7% = 324.24 trillion BTU of methanol required in 2000. This Japanese requirement is 4.8 times the anticipated Panama plant output of 67.87 trillion BTU (that is, 324.24/67.87 = 4.8).

ASSUMPTIONS FOR TABLE 1-B

a. Japanese demand for new fuel oils will rise at 15.8% annually between 1990 and 2000 (MITI projection).

b. One kiloliter of crude has heat value of 39.3 million BTU (1 liter = 39,278 BTU).

c. In 1993, output of Panama plant will be 12,000 short tons per day, or 3.96 million tons of methanol per year (12,000 short tons x 330 days = 3,960,000 short tons).

d. One lb. of methonal has heat value of 8,570 BTU.

e. One short ton of methanol has heat value of 17.14 million BTU (2,000 lbs. x 8,570 BTU).

f. Output of plant, at 3.96 million tons per year in 1993, has heat value of 17.14 million BTU x 3.96 million tons which is ~~6.79~~ trillion BTU.

67.87

Table 1-C

ESTIMATES OF JAPANESE METHANOL FUEL DEMAND BY CHEM SYSTEMS, INC., TARRYTOWN, NEW YORK -- 1985, 1990, 1993 and 2,000

	1985	1990	1993[a/]	2000[a/]
Millions of gallons	200-400	300-600	770	2,850
Average	300 million gals.	450[b/] million gals.	770[b/] million gals	More than[b/] 2,850 million gals.
Average converted to pounds @ 6.6 lbs/ gallon	1,980 million lbs.	2,970 million lbs.	5,082 million lbs.	More than 18,808 million lbs
Demand for methanol in trillions of BTU @ 8,570 BTU per pound	16.97 trillion BTU	25.45 trillion BUT	43.50 trillion BTU	161-283[c/] trillion BTU

a/ Checchi estimates for 1993 and 2000.

b/ Average annual growth in demand for methanol, 1985-1990 is assumed to be 8.5%. From 1990 to 2000, growth is assumed at 19.6%.

c/ Japanese fuel energy demand in 2000 projected by MITI is 725 million KI. Chem Systems, Inc. projects methanol fuel demand as being 1% - 2% of total. Assuming 1% only, then methanol fuel demand will be 7.2 million KI of crude equivalent; at 39.3 million BTU per KI, this is 283 trillion BTU.

became conspicuous. A coal-fired plant (10,000 tons per day) typically emits 34,500 tons per year of SO_2 whereas the CCP plant emits only 430 tons. The direct coal-fired plant emits 29,700 tons per year of NOX while the CCP's emit 5,370 tons; see Annex A, page 10.

In November, 1981, the Tokyo Power Company purchased two, 1000 MW CC Plants from General Electric. The major reason for Japan's recent purchase of CCPs from General Electric was the low SO_2 and NOX emissions. The sale took six years of promotional effort to convince the Japanese of this fact, according to GE.

Capital Requirements

The capital required per KW to build a CCP is low as shown by the following comparisons (from Annex A):

COST PER KW OF INSTALLED CAPACITY	
CCP in the United States	$300-400
CCP in Tokyo	$650
Direct coal-fired plant in U.S.	$2,000
Nuclear plant in U.S.	$7,000

Energy Required to Produce One KWH

Another cost advantage is the heat value required to produce one KWH as shown below (from Annex A):

BTU's REQUIRED TO GENERATE ONE KWH	
Methonal-fired CCP	6,500 BTU's (or less)
Low BTU coal-fired plant	10,500 BTU's
High BTU coal-fired plant	9,700 BTU's

Not reflected above is the fact that coal-fired plants have "scrubbers" to remove toxic emissions; these scrubbers consume six to seven percent of the total power and even so fail to remove 10 percent of the SO_2.

Time Lag in Building Generating Plants

The CCP takes about three years to build whereas a nuclear plant takes from 10 to 15 years. Because the capital requirement per kilowatt of installed capacity rises with inflation (and rises during periods of high interest rates), the CCP is cheaper to build.

Operating Efficiency

A typical CCP can operate at 90 percent of capacity over a 365-day period, whereas a coal-fired plant operates at only 75 percent of the time due largely to maintenance requirements.

CCP's Can Be Built to Small Capacities

Some economies of scale can be gained as the capacity of a CCP is increased, but in general 120 MW's of capacity is the point beyond which economies of scale are not very significant. This means that utility companies can select plants to suit their specific load characteristics and are not forced, for economy reasons, to install plants in the 1,000 MW or higher capacity ranges.

By-products of CCP's

There are other economies offered by the CCP which are not available from the conventional generators of earlier years, for example, in a CCP, it is possible to "cogenerate" steam and electricity and to recover saleable sulfur depending on the sulfur content of coal or gas.

Solid Wastes

The CC Plant combined with a coal gasification plant produces about 27 percent less solid waste than a coal-fired generator (see Annex A, page 10). For a country like Japan where land is scarce, the use of imported methanol (without going through the coal gasification process) will entirely eliminate the accumulation of solid wastes.

1.4 Price Trends

There are many forecasts of price trends, but the concensus is that in future, gas is likely to rise at a faster pace than other fuels influenced in part by the imminent deregulation of gas in the United States. There is also a consensus that coal will continue to remain as it currently is, the lowest priced fuel on a BTU basis. The trend is illustrated below from data contained in the Spring 1982 Energy Review of Data Resources, Inc., a consulting company generally viewed as having conservative forecasts of energy trends:

PRICE TRENDS IN CURRENT DOLLARS PER MILLION BTU
OF THREE ALTERNATIVE FUELS
(Unit: US $ per Million BTU and Percent Annual Growth)

Type of Fuel	1981	1990	2000	Average Annual Growth 1980 - 1990
Crude oil (refiner acquisition)	$6.1	$13.1	$31.5	10.5%
Natural gas, industrial	3.3	11.0	25.0	14.6%
Coal, contract	1.5	4.0	8.7	11.6%

While foreign prices are not the same as U.S. prices, they often follow similar trends. This means that coal, with abundant reserves worldwide, will almost certainly remain the lowest cost fuel for the remainder of the century, ranging from one-fourth in 1981 to 28 percent of the cost of oil in the year 2000. Since methanol can be made from coal feed stock, it will benefit from the price advantage of coal.

1.5 Japanese Interest in Methanol

Other evidence of Japan's interest in methanol includes the following:

The Japanese are installing methanol plants in Saudi Arabia and Indonesia.

Since 1979, four different technical delegations consisting of five to twelve persons have come, with the approval of the Japanese Government (MITI), to study the uses of methanol in the United States.

All delegations were impressed that a methanol-fired power plant of the CCP type takes only three years to build while a coal/methanol plant such as that proposed for Panama takes seven years. This means that the procurement of methanol as opposed to coal, will reduce the capital cost and will eliminate numerous pollution and waste removal problems associated with the use of coal.

As Japan's population and urban areas grow, the problems of waste disposal both solid and atmospheric will intensify. Therefore a clean fuel like methanol will take on greater appeal.

1.6 Availability of Colombian Coal

The EBASCO proposal for a coal/methanol plant in Panama assumes the use of U.S. coal from the Mississippi valley as the feed stock for gasification. Questions have been raised about the possibility of coal exports from Colombia being less expensive than exports from the United States. Therefore, we have examined the outlook for Colombian coal to see if this might replace U.S. coal for the Panama project.

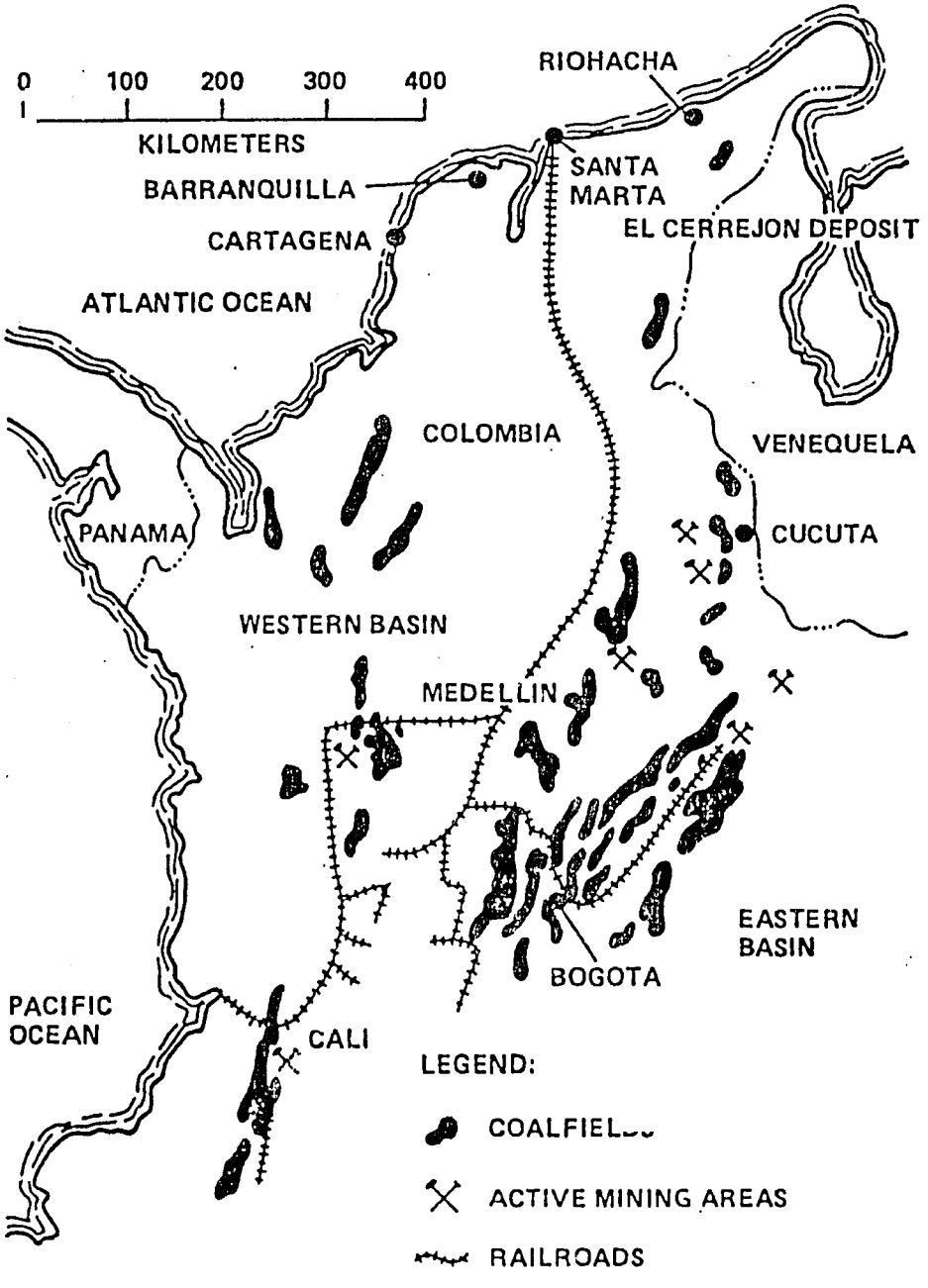
The proposed Panama project when operating at full capacity will require 20,000 tons of coal per day, 330 days annually, starting in 1992. This amounts to a requirement of 6.6 million tons per year.

Most Colombian coals being actively mined are scattered in seams located from 200 to 800 kilometers from the coast (see active mining area in Figure 1). Total exports in recent years of steam and coking coal have been about 200,000 tons per year largely from the El Cerrejon area where EXXON and the Colombian Government have partially developed certain mines.

Exports of steam coal now amount to only 100,000 tons per year. The expectation is that when the EXXON project is completed, steam coal exports will rise to 15 million tons by 1987.

Figure 1

ALTERNATE COAL RESOURCES
COLUMBIA'S EL CERREJON



VITAL STATISTICS

OWNERS:

- INTERNATIONAL COLUMB RESOURCES CORP (EXXON
- CARBONES DE COLUMBIA (GOVT OF COLUMBIA)

SPECS:

- HV 11800 BTU/LB
- SUL – 0.6%
- ASH – 8.5%
- MOISTURE – 9.3

EXXON's experience over the last ten years has been that the development of Colombian mines is an expensive undertaking. This is because all infrastructure such as housing, railways, washing facilitie and port handling facilities and the port itself has to be built from the ground up.

There has been considerable interest in the development of Colombian coal by such companies as British Petroleum and other European interests, but the magnitude of the required investment, over $3 billion, plus the continued problems of law and order have led to no known decisions to invest in the further development of Colombia's coal.

Even given the possibility of 15.0 million tons of steam coal exports by 1987, the transportation problems and the political unrest make Colombia a doubtful source for 6.6 million tons of feed stock coal annually by 1992. Therefore, the possibility of obtaining coal from the Mississippi valley appears far more promising.

Colombian coal has only 0.06% sulfur. Using such coal in Panama would greatly reduce or eliminate the credit obtainable from sulfur recovery during gasification of midwestern U.S. coals (see Topic 2).

On world markets, the low sulfur Colombian coal would carry a premium and could not compete with high sulfur coal from the U.S. midwest.

1.7 Availability of Coal from China

China is both major producer and consumer of steam coal. Production in 1979 was 699 million short tons, and domestic consumption in the same year was about 697 million tons. Exports in 1979 were 2.4 million short tons, or about 0.34 percent of China's production.

In 1981, China's steam coal exports to Japan, the major customer, were 1.2 million (Table 1.7-A). China is anxious to earn more foreign

(Report narrative continues after tables.)

Table 1.7-A

COST OF STEAM COAL IN JAPAN IMPORTED FROM CHINA -- 1981

(Converstion Rate in 1981 was Yen 220.53 = $1.00)

BTN No.	Quantity (MT)	Value (Yen 000's)	Value/MT	Value in U.S.$/MT	Value in U.S.$/ Short Ton
27.01.-129 (not more than 8% ash)	15,756	Y 196,717	Y 12,485	$ 56.61	$ 51.36
27.01-199 (more than 8% ash)	1,188,157	Y 17,245,025	Y 14,514	$ 65.81	$ 59.69
Total	1,203,913	Y 17,441,769			
Average			Y 14,488	$65.70	$ 59.59

Source: Ministry of Finance, Imports by Commodity and Country, IMF for conversion rate (yen 220.53 = $1.00).

Table 1.7-B

JAPAN'S IMPORTS FROM CHINA OF STEAM COAL
CONTAINING MORE THAN 8% ASH (27.01-199)

Year	Metric Tons Quantity	Value (Yen 000's)	Value/ MT	Yen to US$ Conversion Rate	Cost in U.S. $/ MT	Cost in U.S. $/ Short Ton
1978	170,371	1,376,917	8,082	210.44	$38.41	$34.84
1979	256,275	2,118,061	8,265	219.14	$37.72	$34.21
1980	612,826	6,710,609	10,950	226.75	$48.29	$43.80
1981	1,188,157	17,245,052	14,514	220.53	$65.81	$59.69

JAPAN'S IMPORTS FROM THE U.S. OF STEAM COAL
CONTAINING MORE THAN 8% ASH (27.01-199)

1978	--	483	--	210.44	--	--
1979	120	n.a.	n.a.	n.a.	n.a.	n.a.
1980	289,374	4,350,027	15,033	226.75	$66.30	$60.13
1981	2,118,895	34,121,545	16,103	220.53	$73.02	$66.23

Source: Ministry of Finance, Imports by Commodity and Country, IMF for conversion rates of yen to U.S. $.

Table 1.7-C

JAPAN'S IMPORTS OF STEAM COAL FROM CHINA
CONTAINING NOT MORE THAN 8% ASH (27.01-129)

Year	Quantity (MT)	Value (Yen 000's)	Value/ MT	Yen to US$ Conversion Rate	Cost in U.S. $/ MT	Cost in U.S. $/ Short Ton
1978	--	--	--	210.44	--	--
1979	--	--	--	219.14	--	--
1980	14,466	186,505	12,893	226.75	$56.86	$51.58
1981	15,756	196,717	12,485	220.53	$56.61	$51.36

JAPAN'S IMPORTS OF STEAM COAL FOR THE U.S.
CONTAINING NOT MORE THAN 8% ASH (27.01-129)

1978	1,273,739	18,748,380	14,719	210.44	$69.94	$63.44
1979	2,130,209	33,301,753	15,633	219.14	$71.34	$64.71
1980	2,654,918	45,124,878	16,997	226.75	$74,96	$67.99
1981	3,440,129	61,265,061	17,809	220.53	$80.75	$73.24

Source: Ministry of Finance, Imports by Commodity and Country; IMF for conversion rates of yen to U.S. $.

exchange, and exports of steam coal would undoubtedly be allowed to rise if domestic requirements could be met.

If China can export only a fraction of its production (0.34 percent shown above), then to increase its exports to a level sufficient to meet the demands of its foreign customers plus the methanol project in Panama, China would have to raise its production to 2.6 billion tons as compared with the 1979 production figure of 699 million tons. (The calculation is: 6.6 million tons for the Panama project + 2.4 million tons for normal export customers = 9.0 million tons for export = 0.34 percent of 2.6 billion tons).

In considering Chinese coal as a feed stock, account would have to be taken of the fact that U.S. coal averages 4.8 percent more BTU's per short ton than the Chinese coal (based on DOE international comparisons of coal characteristics).

There is a major coal project being seriously planned in the Anshan/Fushun area of Liaoning province in the North to which Occidental Petroleum is committed for financial support. This project will not necessarily add to China's export capability, however, because most of the coal will be used for the industrial expansion of the region.

The proposed Panama coal/methanol project contemplates the procurement of coal at $48.42 (see Ebasco's supplementary information to the U.S. Trade and Development Program, "List of Assumptions," April 1982). This cost figure consists of transport costs of $23.42 and the costs of coal at the mine of $25.00. This price, based on Illinois No. 6 grade, is much lower than the price of coal imported by Japan from China. In 1981, the Japanese paid $59.59 per short ton, or 23 percent higher than the $48.42 price proposed for the Panama project.

The transport costs assumed in Ebasco's planning of the Panama project do not allow for any barge revenue on the back haul from Panama to the Gulf ports. If arrangements can be made for barges to return with loads of crude (Alaskan crude, piped across the isthmus under a project to be completed in the fall of 1982), then the transportation component in bringing coal to Panama might be substantially reduced from the present estimate of $23.42. This will make the Illinois No. 6 even more competitive vis-a-vis Chinese coals. Prices of China's coal delivered to Japan are shown in Tables 17-A, B and C.

1.8 Availability of U.S. Western Coal

There appear to be difficulties impeding the expansion of Western state exports of coal through Pacific ports. We have not been able, during this short review, to verify the difficulties reported to us. For example, Ebasco information is that there are 130 rail crossings between the Utah coal fields and Los Angeles and many of them are within 15 miles of Los Angeles. The movement of long (100-car) "unit" trains carrying coal could disrupt traffic at grade crossings.

Ebasco also points out that some of the Western states may levy "severance" taxes on coal moving through their jurisdictions. There are also Indian reservations which might impose taxes on coal in the future. In short, the climate for heavy investment in coal-moving facilities is somewhat hostile compared with the cordiality shown the mid-west states where reserves of currently un-wanted high sulfur coal are located.

From another industry source, Soros Associates of New York City and from the press, we are told that the exports of western coal were 1.0 million tons in 1981 and that despite the problems, the export tonnage seems to be expanding with a goal of 10 million tons for export by 1987. However, this goal will involve some major capital investment. For example, it takes the equivalent of 400 unit train trips to move

4 million tons of coal and it will take approximately 1,000 trips by such trains to move 10 million tons in 1987. The goal of 10 million tons would require port handling facilities now considered for at least four different ports. Some of the candidate ports are Long Beach, California which plans expansion, and Bellingham, Astoria, and Kalama all in Washington state, which would all require a major construction effort. There are numerous environmental problems involved in coal washing and crushing facilities, grade crossings, and in the expansion or building of ports. (Annex B shows the long delays in obtaining permits for construction of a power plant, for example.)

There are some innovative new proposals being considered that could alleviate in part some of the environmental and cost problems now prevailing. The Department of Commerce, Coal Task Force is now reviewing a proposal from the W. R. Grace & Company which calls for the shipment in plastic bags of pre-washed, pre-crushed coal from areas near the Colorado River to the Pacific Coast. The port is not yet designated. The plastic bags would be carried in saline water which has to be removed from the Colorado River in any event by the Bureau of Reclamation. Japanese interests are reported by the Coal Task Force as being willing to invest $500 million in a feasibility study regarding this project.

Even if the developmental problems could all be overcome, costs of coal will also remain a factor. Table 1.7-B shows that high ash U.S. coal (more than 8 percent) cost $66.23 delivered to Japan in 1981. Table 1.7-C shows that low ash coal was delivered to Japan in 1981 at $73.24 per short ton. Articles in the New York Post of May 4, 1982 indicate that U.S. steam coal from Utah and Colorado is being delivered to Japanese utilities and steel makers at $75 per ton, $10 higher than equivalent Australian coals.

These costs compared with the 1981 estimated costs for Illinois No. 6 of $48.42 would appear to make feed stock from western coals

ıattractive from the economic point of view. Western coal has a low ılfur content and therefore carries a premium price which makes it non-ımpetitive for purposes of the Panama coal/methanol project.

TOPIC 2

"The projection that methanol produced in Panama from U.S. coal will be price competitive, after amortization of debt, with methanol produced from natural gas in a Pacific Rim country."

Coal is competitively and openly priced with other fuels, while natural gas can be a waste product or have a regulated price, or an open market price depending on local situations. In order to avoid the waste and price regulations, natural gas is liquified to make LNG and compressed at sub-zero temperatures for shipment to distant markets often overseas.

In any case, prices for these raw or semi-finished materials are alone not particularily informative in making comparisons. More informative is the price after conversion to a final product such as electric power because conversion costs themselves vary depending on the type of energy resources used.

In order to better illustrate the price complexities involved (including transportation costs and national economic differences) coal, fuel oil, natural gas, LNG, and methanol energy systems have been analyzed. In summary form, the following table shows the cost of producing one kilowatt hour based on generating electric power in a standardized 1000 megawatt capacity plant. (The Japanese do not use natural gas except in the form of regasified, imported LNG.)

ELECTRIC POWER PLANT COSTS
IN U.S. MILLS PER KILOWATT-HOUR -- 1981 PRICES

	Coal	Fuel Oil	Natural Gas	Methanol
Case I:				
U.S. Conditions	97.7	97.0	38.0	98.5
Case II:				
Japanese Conditions	104.0	104.9	81.5 (LNG)	94.1

Appendices A through D which follow show the calculations.

The cost comparisons for coal and fuel oil are much as would be expected. The competiveness of Panama methanol is interesting and results from its cleanliness, low cost of conversion to electric power, and its use of low cost, high sulfur coal from the U.S. midwest. The methanol cost is lower in Japan because large bulk carriers can be used with their lower unit charges for moving methanol from Panama to Japan.

LNG is produced in Pacific Rim countries, U.S.A., Brunei and Indonesia and sold in 1981 at the following prices per short ton delivered to Tokyo Bay: $285.82; $279.60; $237.46, respectively. The resulting cost in mills/kwh, if each source were used exclusively would be 85.0; 82.9; 75.7, respectively.

On the basis of 1981 levelized costs, it is clear that Panama methanol is not, at the present time, competitive with Pacific Rim LNG. Nevertheless, we cannot stop the analysis with 1981 but must try to look also into the future. The case of natural gas under U.S. conditions is helpful in this regard. Natural gas is being deregulated, and is in limited supply for electric power because it has higher value in other domestic uses. The final result will be higher costs and the encouragement of foreign sources to increase their natural gas prices also. This trend is already in evidence and the energy industry is predicting that in the 1990's, natural gas will be priced competitively with oil on a BTU per unit basis.

The trend is that natural gas prices will rise faster than other fuels as shown in the following tabulation:

U.S. PRICE TRENDS IN CURRENT DOLLARS
OF THREE ALTERNATIVE FUELS

Type of Fuel	1981	1990	2000	Average Annual Growth 1980 - 1990
	($ / million BTU)			
Crude Oil (refiner acquisition)	6.1	13.1	31.5	10.5%
Natural Gas, industrial	3.3	11.0	23.0	14.6%
Coal, contract	1.5	4.0	8.7	11.6%

Source: Energy Review, Data Resources, Inc. (a consulting company generally viewed as having conservative forecasts of energy trends).

In general then, energy planners cannot base future project development on present low prices for natural gas. This means that LNG-based projects may well be facing stronger competition from alternative fuels such as coal and methanol from coal. Diversified energy sources appear almost mandatory for a sound energy policy. The Panama Complex is a good candidate project for inclusion under such a policy, based on the above analysis. In this sense, Panama-produced methanol will be price competitive with methanol produced from natural gas in Pacific Rim countries.

The basic causes of this phenomenon are: (a) low cost coal from Illinois ($48.42/ton) and (b) the inevitable price rise in natural gas which is in far more limited supply than coal.

DATA SOURCES

A. EBASCO, April 1982, Supplementary Information, Panama Coal Gasification - Methanol Complex.

B. Monthly Energy Review, DOE/EIA-0035(82/04), U.S. Department of Energy.

C. Cost and Quality of Fuels for Electric Utility Plants, DOE/EIA-0075(81/12), U.S. Department of Energy.

D. Bartlesville Technology Center, Bartlesville, Oklahoma.

E. Alcohol Week, Washington, D.C., April 14, 1982.

F. International Energy Annual, DOE/EIA-0219(80), U.S. Department of Energy, September 1981.

G. Introduction to "Energy and Japan," The Institute of Energy Economics, Tokyo, October 1981.

H. Petroleum Economist, January 20, 1982

Appendices to this discussion of Topic 2 follow.

APPENDICES

Four appendices follow to show the data and methods of calculation used in the above discussion of Topic 2.

Appendix A uses the "present value" concept of money to compute a single value for the fixed and variable operating costs which represent revenue requirements. This concept is a particularly useful and accepted method in the financial community for reducing future cost streams to a common base year. The equation is:

$$\text{"Present value"} = \text{amount} \times 1/(1+i)^{n}$$

Where: i = interest rate
n = number of periods, in this case years.

Appendix B presents 1981 prices for alternative fuels with reference sources and points of use. Where costs per million BTU are given, they are converted to U.S. dollars per unit such as short tons of 2000 pounds (ST), barrels (bbl), and thousand cubic feet (mfc). The price data are then summarized by fuel and for the U.S. and Japan. Japan is the target market for Panama methanol.

Appendix C shows calculations and results in mills/kwh of electric power in the case of U.S. conditions. The BTU per kilowatt hour (kwh) of 3412 is an engineering constant. The input of BTU's needed to produce one kilowatt hour of electricity were provided by EBASCO on the basis of its work on power plants. The plant levelized operations expenses for 1981 in mills/kwh were provided also by EBASCO.

Appendix D is similar to Appendix C and shows comparable costs and results for Japanese conditions.

The "bottom line" of this analysis (in Appendix D) is the fact that under Japanese conditions, the cost per kwh of power in 1981 prices is as follows for the four fuels, expressed in U.S. mills:

Coal	104.0
Fuel Oil	104.9
LNG	81.5
Methanol	94.1

We think LNG will rise, however, in sympathy with U.S. deregulation.

APPENDIX A

PROJECT METHANOL PANAMA PACIFIC COAST: 1981 PRESENT VALUE CALCULATIONS

	Costs by Year				Present Values by Year			
Year	Princ. and interest	Coal input	Expense less sulfur	8% disc. rate 1981	Princ. and interest	Coal input	Expense less sulfur	Methanol output tons/d
	(--- U.S. $ millions --)			$1/(1+i)^n$	(--- U.S. $ million --)			
1990	1758	319	242	.5003	879	160	121	6000
91	1940	517	295	.4632	899	240	137	9000
92	1805	745	355	.4289	774	320	152	12000
93	1429	805	384	.3971	568	320	152	12000
94	1335	869	414	.3677	491	320	152	12000
95	1241	939	447	.3405	423	320	152	12000
96	1147	1014	483	.3152	362	320	152	12000
97	1053	1095	522	.2919	307	320	152	12000
98	959	1182	564	.2703	259	320	152	12000
99	865	1277	608	.2503	217	320	152	12000
2000		1379	658	.2317		320	152	12000
01		1490	710	.2146		320	152	12000
02		1609	767	.1987		320	152	12000
03		1737	828	.1839		320	152	12000
04		1876	894	.1703		320	152	12000
05		2026	966	.1577		320	152	12000
06		2189	1043	.1460		320	152	12000
07		2364	1127	.1352		320	152	12000
08		2553	1217	.1252		320	152	12000
09		2757	1314	.1159		320	152	12000
2010		2978	1419	.1073		320	152	12000
11		3216	1533	.0994		320	152	12000
12		3473	1656	.0920		320	152	12000
13		3750	1788	.0852		320	152	12000
14		4051	1931	.0789		320	152	12000
15		4375	2086	.0731		320	152	12000
16		4720	2253	.0676		320	152	12000
17		5103	2433	.0626		320	152	12000
18		5511	2627	.0580		320	152	12000
19		5952	2838	.0537		320	152	12000
30 year life					----	----	----	------
	Totals				5179	9360	4514	351000
					1/30	1/30	1/30	
Average cost per ton of methanol					44.71	80.81	38.97	

1981 Total average cost, 1981 prices $ 164.49 / ST

Source: Costs by year from ERASCO Supplentary Information, Panama Methanol Complex, April 1982, pages 23-25; Present values by year derived by Checchi and Company.

APPENDIX B

FUEL PRICE DATA and SUMMARY

Ref.

A. EBASCO, April 1982, Supplementary Information, Panama Coal Gasification - Methanol Complex.

Methanol Cost / ST Panama		$ 164.49
U.S. delivery	$ 24.00	188.49
Japan delivery	15.00	179.49

Japan delivery is less due to use of large bulk carriers.

B. Monthly Energy Review, DOE/EIA-0035(82/04), U.S. Department of Energy.

1981 Average Petroleum Prices	Dollars/barrel
Residual Oil Price [Elect. Utilities]	
0.31 to 1.0 % sulfur	30.55

1981 Cost of Fossil Fuels Delivered to Steam-Electric Utilities

	Cents/million BTU	$/unit
Coal	153.3	32.65/ST
Residual Oil	529.0	33.03/bbl
Natural Gas	282.8	2.913/mfc

C. Cost and Quality of Fuels for Electric Utility Plants, DOE/EIA-0075(81/12), U.S. Department of Energy.

Fossil Fuel Receipts at Steam-Electric Units

Nov. Dec. 1981	Cents/million BTU	$/unit
Coal	158.2	33.59/ST
Oil	517.3	32.26/bbl
Gas	295.7	3.055/mfc

Coal (Btu/lb)	10619
Oil (Btu/gal)	148491
Gas (Btu/cubic foot)	1033

D. Bartlesville Technology Center, Bartlesville, Oklahoma.

Methanol BTU/gal	56,560
Methanol weight/gal	6.6 lb

E. Alcohol Week, Washington D.C., April 14, 1982.

Methanol Contract Prices

Texas, April 14, 1982	$ 0.715 / gal
California, April 14	0.795 / gal
Methanol Spot Market	0.510 / gal

Note that Panama methanol 1981 'present value' cost is $ 164.49 per short ton or $0.54 per gallon.

F. International Energy Annual, DOE/EIA-0219(80), U.S. Department of Energy, September 1981.

Japan, Tokyo - Electric Utility Price 1981

Heavy Fuel Oil 3% sulfur	40.62 / barrel

G. Introduction to 'Energy and Japan', The Institute of Energy Economics, Tokyo, October 1981.

Price of Energy Imported into Japan 1980

LNG $/MMBTU	$ 5.03	$240.82/ST
Fuel Oil C $/MMBTU	5.33	33.22/bbl
Coal $/MMBTU	2.15	47.98/ST

Calorific Value	
LNG	13300 Kcal/kg
Fuel Oil	9900 Kcal/liter
Coal	6200 Kcal/kg

H. Petroleum Economist, Jan 20, 1982

Cost of LNG in Tokyo Bay 1981	$/MMBTU	$/short ton
From Brunei	5.84	279.60
From Indonesia	4.96	237.46
From U.S.	5.97	285.82
From Abu Dabi	6.53	312.63
Average of above	5.83	278.88

SUMMARY OF FUEL PRICES

U.S.A	Ref.		$ per unit
Methanol	A	delivered	189.49 / ST
	E	216.67	
	E	240.91	
	E	154.55	
Coal	B	32.65	
	C	33.59	
		Average	33.12 / ST
Fuel Oil	B	30.55	
	B	33.03	
	C	32.26	
		Average	31.95 / bbl
Gas	B	2.916	
	B	2.913	
	C	3.055	
		Average	2.961 / mfc

JAPAN	Ref.		$ per unit
Methanol	A		
Panama delivered			179.49 / ST
Coal	G		47.98 / ST
Fuel Oil	F	40.62	
	G	33.22	
		Average	36.92 / bbl
LNG	F		240.82 / ST
	H	Brunei	279.60 / ST
	H	Indonesia	237.46 / ST
	H	U.S.A	285.82 / ST
	H	Abu Dabi	312.63 / ST
	Average		271.26 / ST

APPENDIX C

ELECTRIC POWER COSTS USING ALTERNATIVE FUELS
U.S.A CASE, 1981 Prices

	Coal	Fuel Oil	Gas	Methanol
Kilowatt hours	1	1	1	1
BTU per kwh	3412	3412	3412	3412
BTU Input per kwh	10300	10000	8200	7600
Heat cycle efficiency	33.1%	34.1%	41.6%	44.9%
Fuel Prices:				
Coal $/ST	33.12			
Fuel Oil $/bbl		31.95		
Gas $/mfc			2.961	
Methanol $/ST				189.49
Million of BTUs in Fuels:				
Coal	21.300			
Fuel Oil		6.244		
Gas			1.033	
Methanol				17.139
Power Plant Costs:				
Cost of Fuel in mills/kwh Equation [Input*Price/BTU]				
Coal	16.0			
Fuel Oil		51.2		
Gas			23.5	
Methanol				84.0
Plant Operating Expense:				
Regular cost in mills/kwh				
Capital charges	47.9	24.7	10.1	10.1
Expenses	21.5	10.8	4.4	4.4
Special cleaning & handling in mill/kwh:				
Capital charges	8.4	7.0		0.
Expenses	3.9	3.3		0.
Total cost in mills/kwh	97.7	97.0	38.0	98.5

Costs are based on 1000 megawatt plant capacity.

APPENDIX D

ELECTRIC POWER COSTS USING ALTERNATIVE FUELS
JAPAN CASE, 1981 Prices

	Coal	Fuel Oil	LNG	Methanol
Kilowatt hours	1	1	1	1
BTU per kwh	3412	3412	3412	3412
BTU Input per kwh	10300	10000	8200	7600
Heat cycle efficiency	33.1%	34.1%	41.6%	44.9%
Fuel Prices:				
Coal $/ST	47.98			
Fuel Oil $/bbl		36.92		
LNG $/ST			271.26	
Methanol $/ST				179.50
Million of BTUs in Fuels:				
Coal	22.138			
Fuel Oil		6.245		
LNG			47.876	
Methanol				17.139
Power Plant Costs:				
Cost of Fuel in mills/kwh Equation [Input*Price/BTU]				
Coal	22.3			
Fuel Oil		59.1		
LNG			46.5	
Methanol				79.6
Plant Operating Expense:				
Regular cost in mills/kwh				
Capital charges	47.9	24.7	10.1	10.1
Expenses	21.5	10.8	4.4	4.4
Special cleaning & handling in mill/kwh:				
Capital charges	8.4	7.0	17.4	0.
Expenses	3.9	3.3	3.1	0.
Total cost in mills/kwh	104.0	104.9	81.5	94.1

Costs are based on 1000 megawatt plant capacity.

Note: If Brunei and Indonesia LNG prices were used in the above calculations, the total cost in mills/kwh would be 82.9 and 75.7, respectively.

TOPIC 3

"The assumption that Japan will seek diversified sources of supply of methanol."

Japan has traditionally followed a policy of diversifying its sources of raw materials to help assure its supply security. For example, phosphate rock comes from Florida in the U.S., Morocco, the island of Nauru, and Tunis. Lead, zinc, iron ore, coking coal, petroleum procurement is dispersed widely. The Japanese try to avoid a concentration of their procurement effort in any single source.

In the case of methanol, as dependency begins to build up in the 1990's, it is logical to believe that Japan will adhere to its traditional policy of diversifying its sources of supply.

As mentioned under Topic I (Section 1.2.1), Japanese demand for methanol by 1993 (one year after the Panama project operates at full capacity) would be on the order of 116.7 trillion BTU. The Panama plant would produce 12,000 tons of methanol per day or 3.96 million tons annually. This output would have a heat value of 6.79 trillion or one seventeenth of the estimated Japanese methanol requirement in that year.

By 1990, we anticipate that Japan's requirements for methanol will be growing at a fast pace with more than a four-fold increase from 1990 to 2000. See "new fuels" near the bottom of Table 1-A, under Topic I. This means that even in 1993, the Panama plant will meet only 6 percent (1/17th = 6%) of Japan's needs. This suggests that the Japanese will want to procure from several countries where they think conditions will be most competitive.

However, it is difficult to imagine how they could find a lower cost feed stock than the Illinois No. 6 transported to Panama for

gasification and conversion to methanol. This suggests that they may find it advantageous to arrange for U.S. midwestern coals to be processed at off-shore localities other than Panama, but still close to the Gulf ports.

TOPIC 4

"The prospects for bilateral arrangements between Japan and the U.S., whereby Japan would reduce its trade surplus with the U.S. by importing U.S. fuels, including methanol."

The Japan Economic Journal (English edition) of April 20, 1982 reported:

> "Japan and the United States will set up a bilateral consultative consulting body to coordinate promotion of Japanese imports of U.S. energy resources such as coal in the western U.S. and Alaskan crude oil."

We informed the Coal Task Force of the Department of Commerce about this press article. We were told by the Task Force that the article was wishful thinking on the part of the Japanese and that the U.S.-preferred remedy for reducing the $20.0 billion trade deficit with Japan was to expand U.S. exports of manufactured goods.

The Japanese, on the other hand, have been pressing for alternative remedies and do not want to see an expansion of U.S. manufactured goods exports. One of the alternatives that the Japanese have proposed informally is a stepped-up program of importing U.S. energy resources. The Japanese think this will relieve the pressure on them to accept U.S. manufactures. However, from the U.S. point of view, the export of energy is no substitute for more U.S. exports of manufactured goods to Japan.

The U.S. Trade Representative's Office (Joseph Massey) said the above press report was wrong and there was no agreement between the U.S. and Japan to remedy the imbalance of payments by increasing the exports of U.S. energy resources.

The USTR Office also said that the export of energy resources to offset the U.S. trade deficit with Japan was not on the planned agenda for the international meeting of heads of state scheduled to take place soon in Versailles.

The fact remains, however, that many people both in the U.S. and Japan would like to see increased exports of U.S. surplus coal. If these same people were aware of the Panama coal/methanol project, it would seem logical that they would favor that project also since the project will, in effect, result in the export of U.S. coal in a processed form.

TOPIC 5

"The economic and technical advantages or disadvantages of produc methanol in the U.S. as compared with Panama, for export to the Pacifi

5.1 Economic Advantages

An economic advantage occurs whenever a low grade and consequentl low priced product can be enhanced by processing to a higher grade and higher priced product. This is the essence of the Panama coal/methano project. The project will utilize U.S. midwest coal of low grade and low price because of its high sulfur and ash content.

The project will process this coal to remove the ash (for land fi and road beds) and recover the sulfur (a salabl product). In doing s the project will produce methanol as a clean, high energy product carr ing a relatively higher price. The economic opportunity cost is low f the U.S. because high-sulfur, ash coals are almost useless in the U.S. where environmental considerations have high priority and better coals abound.

The project will result in distinct economic advantages such as:

Economic Advantages of the Project for the United States

- Export of 186.4 million tons of midwestern coal valued at $9.4 billion over life of plant (this coal would otherwise remain unused until U.S. sources of better coal are exhausted)
- $7.0 million in value added in U.S. industry for the construction of ocean going towed barges (1,000 barges for 20,000 ton/day coal lift ex U.S. Gulf, 10-day turn-around)
- Employment of thousands of miners and hundreds of barge crewmembers for inland waterway and ocean transportation of 20,000 tons/day of midwest coal.

- Export of U.S. equipment and services.
- Improves economic stability within the Caribbean Basin.
- Supports the U.S. government's private sector investment overseas in lieu of direct government aid
- Contributes towards establishing price ceilings on mid-east crude sources

Economic Advantages of the Project for Panama

- Opens the northeastern area of Panama for commerce and industry
- Creates about 3000 construction jobs and 800 permanent jobs
- Infrastructure development includes housing, educational, medical and recreational facilities
- Provides the basis for additional industrial and natural resources development
- Enhances Panama as a trading partner with U.S./Japan
- Provides a hydrocarbons feedstock base for creating a future petrochemical industry
- Generates available blocks of relatively low cost electric power for regional growth
- Creates no adverse impact on Panama Canal traffic
- Panama obtains a potential source of methanol as an independent fuel base to meet growing fuel requirements
- Provides an opportunity for local engineers and contractors to supply equipment and services
- Creates a potential stable supply of cooking and heating gas for local consumption
- Makes available the production ammonia and sulfuric acid in the form of (fertilizer) for agricultural uses
- Future expansion of the world's methanol needs can be achieved by adding to the initial installation in Panama and thus create additional work and investments in Panama

- Provides a potential for expansion for the production of coal-methanol slurry for delivery to Japan

Economic Advantages of the Project for Japan

- Provides environmentally acceptable fuel alternatives to mideast sources
- Provides high quality, clean fuel consistent with Japan's Long Range Energy Planning
- Provides diversification of coal resources, reducing Japan's growing dependence upon Australia
- Provides access to a stable U.S. midwestern coal supply region with large reserves for export
- Offsets the current U.S. Japan balance of trade deficiencies by exporting U.S. coal
- Contributes towards price ceilings on mideast crude sources
- Reduces need to install new capital intensive coal fired steam-electric generating capacity
- Reduces land use and environmental problems associated with direct coal use in Japan
- Reduces need for ash/sludge disposal areas in Japan
- Methanol is versatile alternative fuel with minimum retrofits for gas turbines, boilers and transportation fuels
- Methanol transport can utilize the existing charter market for crude tankers

Economic Advantages of the Project for Western Europe

- Provides a market for western European gasification technology and equipment sales
- Provides an alternative fuel source based on U.S. coal that is independent of middle east and communist block countries
- Contributes indirectly towards establishing price ceilings on mideast crude sources

Economic Disadvantages

It can be argued that the siteing of the methanol plant in Panama deprives the U.S. of certain advantages such as: jobs will be generated overseas which otherwise could be generated in the U.S.; much of the heavy equipment, tanks, pipes, and pumps will be bought from Japan (see below) instead of the U.S.; the security climate in Panama is not as favorable as in the Mississippi valley.

However there are some practical reasons why the plant cannot be sited in the U.S.:

- The regulatory process will take nearly four years and capital costs will rise by one-third or more -- see Annex B.

- Approval of this project will require the financial support of an international consortium including the Japanese. In Japan, the trading companies and their supporting manufacturers are a powerful interest group. If they see the opportunity to export plant and equipment worth several billion dollars, they will lend their support to the project and they will help shape attitudes favorable to the project in MITI, the Ministry of Finance, and in the utility companies. Without enlisting the help of the trading companies, Japanese support could well be insufficient to convert the Panama project from a concept to reality.

- Siteing the plant in the U.S. would lessen if not eliminate the possibility of Japanese supply of heavy plant and equipment. That is, the import of heavy vessels, pipes, and pumps from Japan would arouse opposition in the U.S. from labor and industry that could well doom the project and delay the regulatory approval process even more than at present.

- The security climate for investment in Panama may not be as favorable as that of the Mississippi valley, but we believe security in Panama is an acceptable risk when compared with the advantages already cited. Many U.S. companies, including the Texaco refinery have been operating successfully for decades in Panama and traffic through the canal has not been interrupted by political disturbances.

5.2 Technical Advantages

The technical advantages or disadvantages must take into account the present rapid evolution in energy conservation, production, and utilization of new approaches. The concept of converting coal to methanol is not new, but it has not been widely used, given the current price comparisons of different fuels. With the near future gas deregulation and price rises (see Topic 2), methanol has definite advantages in terms of lower maintenance, higher capacity utilization, and much cleaner emissions.

5.3 Political Advantages

The present administration of Panama is making a major effort to improve the standards of living of its citizens. Per capita GNP in 1980 was $1,730, about half that of Puerto Rico. Such figures are misleading, however, because living standards in rural areas are far worse than in the cities.

The proposed project site, close to the Costan Rican border, is one of the least developed of Panama's rural areas. With an election expected in 1984, it will be in the U.S. interest to help create conditions that will strengthen Panama's incumbent administration.

A major infusion of private investment in Panama will supplement the U.S. Government's official aid as part of the new initiative to increase personal well being in the Caribbean basin.

The $20 billion annual deficit in U.S.-Japan trade has created political frictions. The exports of U.S. coal needed to supply the Panama project will help offset the overall U.S. trade deficit and could reduce political frictions between the two countries (see Exhibit 5.3 on the next page).

Article from Washington Post, May 6, 1982

Spat With Japan Called Serious

Bergsten: Conflict Worsening

By Hobart Rowen
Washington Post Staff Writer

5/6/

The current American-Japanese economic conflict is "extremely serious and will get much worse," international economics expert C. Fred Bergsten said yesterday in a speech to the Japan Society in New York.

He labeled the current episode "the nastiest" of three in the past 12 years, with racist overtones already present, and an "obvious spillover to the re-emerging issue of security relations between the two countries."

Bergsten, an assistant Treasury secretary in the Carter administration and now director here of the Institute for International Economics, blames Japanese-U.S. problems primarily on a "severe exchange-rate misalignment between the dollar and the yen."

He offered a new idea—admittedly "a bit unorthodox"—on how to bolster the weak Japanese currency. His idea is that Japan should once again "manipulate" its capital account, as he said it had done in 1979-80, to limit capital outflows and to promote capital inflows.

A cheap yen—now 245 to the dollar—results in a strong price advantage for Japanese goods. In turn, this boosted the Japanese trade surplus with the United States to $18 billion last year, Bergsten said. He predicted that Japan's trading edge would remain relatively

See JAPAN, D13, Col. 1

EXHIBIT 5.3 (concluded)

U.S.-Japan Trade Conflict Called Serious

JAPAN, From D12

unaffected unless the yen were to strengthen to between 180 and 200 to the dollar.

Bergsten did not take issue with the more or less standard explanations of U.S.-Japan trade frictions focusing on Japanese protectionist instincts, government guidance of and help for business, and American failures on the productivity and export promotion fronts.

But he argued that none of these "phenomena" explains "the periodic outbursts of U.S.-Japan economic conflict which have occurred on three fairly discrete occasions over the past 12 years." Rather, he says, the exchange rate has been "the villain" in all three periodic conflicts, with the dollar in each case moving into an overvalued position vis-a-vis the yen.

He said that the best way to cure the situation would be an altered macroeconomic policy mix in the United States and Japan that would narrow interest rate differentials. But because this is not in the cards as a realistic option, Bergsten argued that the best way to boost the yen rate against the dollar would be for Japan to impose a temporary moratorium on all capital outflows by Japanese residents, including those made for foreign direct investment.

In addition, he said that the Japanese government should follow an "aggressive" policy of borrowing abroad to finance its domestic budget deficit. "The result would be a dramatic improvement in Japan's capital account, which should immediately push the yen substantially upward," he predicted. Among other steps he recommended is an aggressive Japanese effort to attract foreign investment in government yen-securities, presumably by paying high interest rates.

Bergsten said the United States should endorse such a Japanese initiative, and support it by intervening directly in the exchange markets to bolster the yen. He charged that the Reagan administration's refusal to intervene in exchange markets was one of the main factors in keeping the yen at an undervalued level.

In addition, he blamed protectionist rhetoric for weakening the yen, because it gives rise to fears that Japanese exports will be reduced in the future.

TOPIC 6

"The technical and economic problems of shipping U.S. coal from the midwest and southern coal fields to Panama."

There are indeed problems facing the shipment of U.S. coal to Panama. While some of them may seem formidable, they are surmountable and similar challenges have been met elsewhere in the past. Some of these problems and comments thereon are as follows:

1. A large number of ocean-going, towed barges will be needed to ship 20,000 tons of coal per day from Gulf ports to Panama. However, the lead time between 1983 and 1990 is sufficient to permit the construction of such barges.

2. There may be problems with the locks in the Mississippi which are now managed by the Corps of Engineers. Again, the lead time is such that improvements in the locks and expansion of capacity could overcome this difficulty by 1990. Major economies in inland transportation are available thanks to the network of canals and improved waterways leading to Mobile and New Orleans.

3. A special ocean-going barge will have to be designed to carry the coal to Panama. This presents no formidable technical problems and has been done before.

4. To supply 20,000 tons of coal per day, old mines will have to be reactivated and new ones developed. There are substantial reserves of undeveloped coal in Ohio, Indiana, Tennessee, Missouri, and Alabama. With an assured market, these mines could be activated.

5. If coal is assembled from a variety of mines, it will probably require a blending plant in Panama to make the feed stock uniform in quality. This will depend upon negotiations with the major coal suppliers some of whom may be able to provide coal from a single seam.

6. Illinois mines are partially developed but had to be abandoned because of the high sulfur content of coals. These can be reactivated more readily than new mines can be developed. Utilities have begun to experience a reduced demand for power, and coal is therefore declining in use. Mine owners will respond readily to new demands in Panama.

7. The special ocean-going barges mentioned above would have to be built to carry the coal to Panama and they would probably be organized by the coal producers themselves who would take responsibility for the construction of the fleet.

8. At least two alternative technologies are available for converting the barges from coal to oil so that the return voyage from Panama could be revenue producing. A double hull could be constructed or rubber sheathing could be laid in the hold for carrying coal and removed when carrying oil.

9. We anticipate that the coal producers will form a consortium to mine and barge the coal. Some of the major producers are Conoco, Houston Natural Gas, and Keystone. (On the Panama side, the PTP would handle the pipeline transportation of the methanol and would also manage the loading of methanol into tankers as they are doing for crude oil. There would be contract penalties between the international consortium managing the Panama plant and the consortium of U.S. producers. Penalties would be agreed regarding delivery dates, quality and quantities of coal.

TOPIC 7

"The technical and economic problems of transportation and storage of methanol."

The project must have a 30 to 60 day storage for coal on the Caribbean side and the same for methanol on the Pacific side. This is for surging and holding and to assure a steady supply of feed stock to the plants and methanol to the tankers.

There are corrosion problems involved in handling methanol because methanol is hydroscopic. This means that pipelines and storage tanks will be more subject to oxidation than is the case with oil tanks. However, this has been overcome in other places. Methanol is now produced in Alberta and is piped 1,000 miles to Vancouver for storage and loading.

In the U.S. Gulf states, there are pipelines carrying methanol. In New Orleans, existing oil pipelines were retrofitted and initial problems were solved and pipelines are now working well. In California, there are AMFE codes regulating methanol handling which means that handling procedures have become routine.

However, none of the problems associated with methanol are anything like as complex as those associated with the cryogenic handling of frozen gases such as LNG and LPG. In Japan, tanks, pipelines, tubing now used for oil or gas could also be used for methanol with minor modifications.

It is expected that the tankers carrying methanol from Panama would be conventional (not cryogenic) in the 200,000 dwt range. There is a world wide surplus of these tankers and the cost of transportation according to Poten & Partners, 711 Third Ave., New York, would be as low as $5.00 per ton to Yokohama (consecutive voyage basis, every two months, two-year charter). Because of the 4,000 foot mountain range to

be crossed, doubts have been expressed by some of the people we interviewed about the pipeline transportation of methanol from the Caribbean side to the Pacific side of the Isthmus. However, the fact is that the Morrison Knudsen project to transport Alaskan crude along the same pipeline right of way is going well, and crude oil should be moving through the pipeline in October 1982, the scheduled completion date. (See Annex C, a report on the Morrison-Knudsen pipeline project in Panama.)

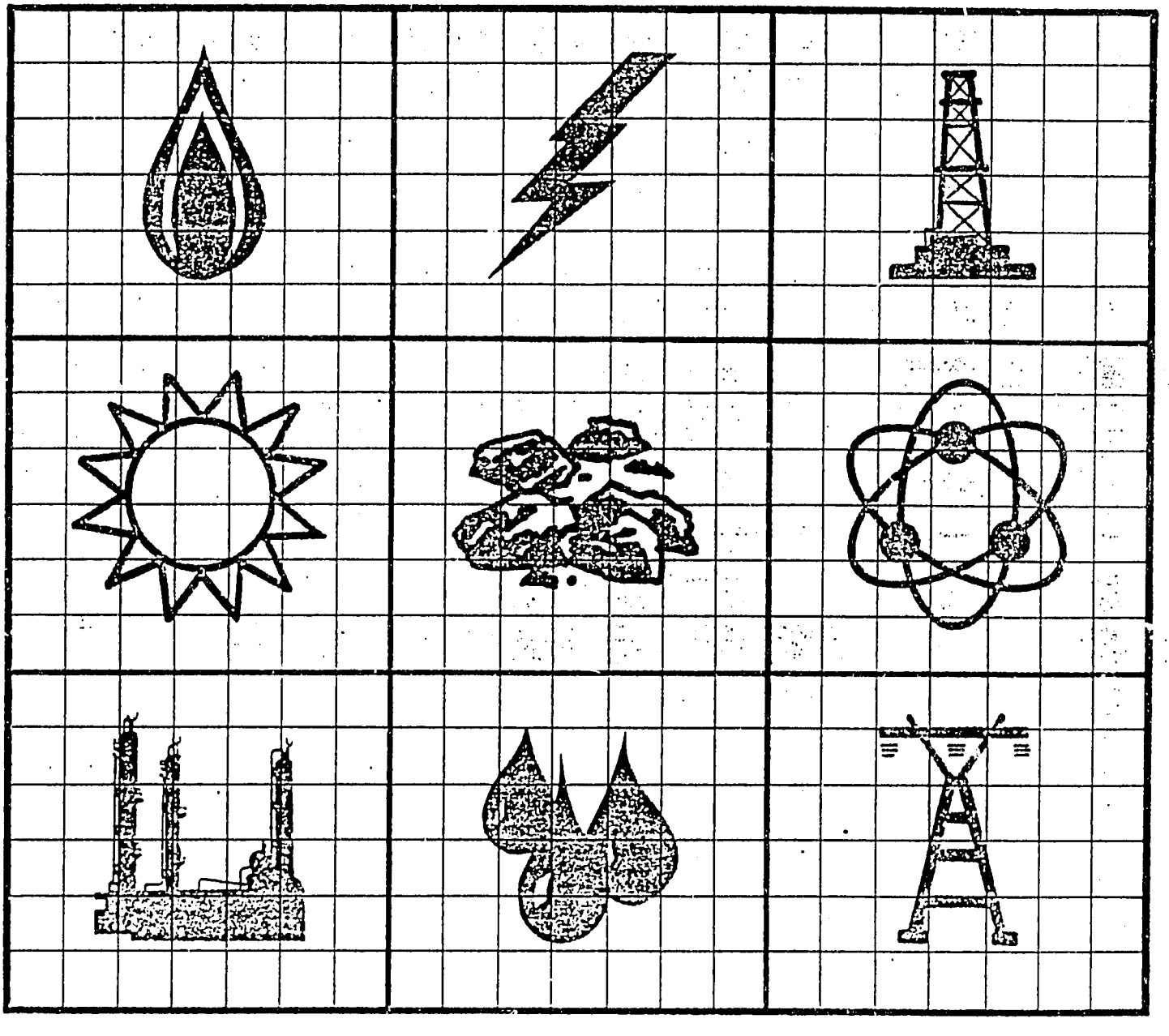
ANNEX A

COAL GASIFICATION IN POWER GENERATION--
AN ALTERNATIVE STRATEGY

EBASCO

Coal Gasification in Power Generation— An Alternative Strategy

by J. P. Lekstutis, Manager of Projects, Envirosphere Company,
a Division of Ebasco Services Incorporated
and M. S. Brown, Projects Manager



American Power Conference, April 1982

INTRODUCTION

Medium Btu coal gasification combined cycle systems can be environmentally and economically attractive alternatives to direct coal firing. Depending on the daily demand for medium Btu gas (MBG) and electrical power, the MBG approach provides the potential for cogeneration of steam and electricity and the production of alternate fuels and by-product chemicals. It also holds the potential for joint venture operations wherein third parties undertake the coal conversion activities while the utility limits its investment to the combined cycle power generation facilities only. Alternatively, a utility may sponsor the development of the complete coal conversion, cogeneration, and alternate fuel production facilities in an aggressive approach to entering new energy markets.

Drawing largely on developments of ongoing project feasibility studies, this paper will address: the production of medium Btu gas from coal as a potential fuel source for utility and industrial application; the use of MBG in cogeneration and for the production of alternate fuels and by-product chemicals; and the economic and environmental implications of the MBG approach by comparison with a direct coal fired alternative.

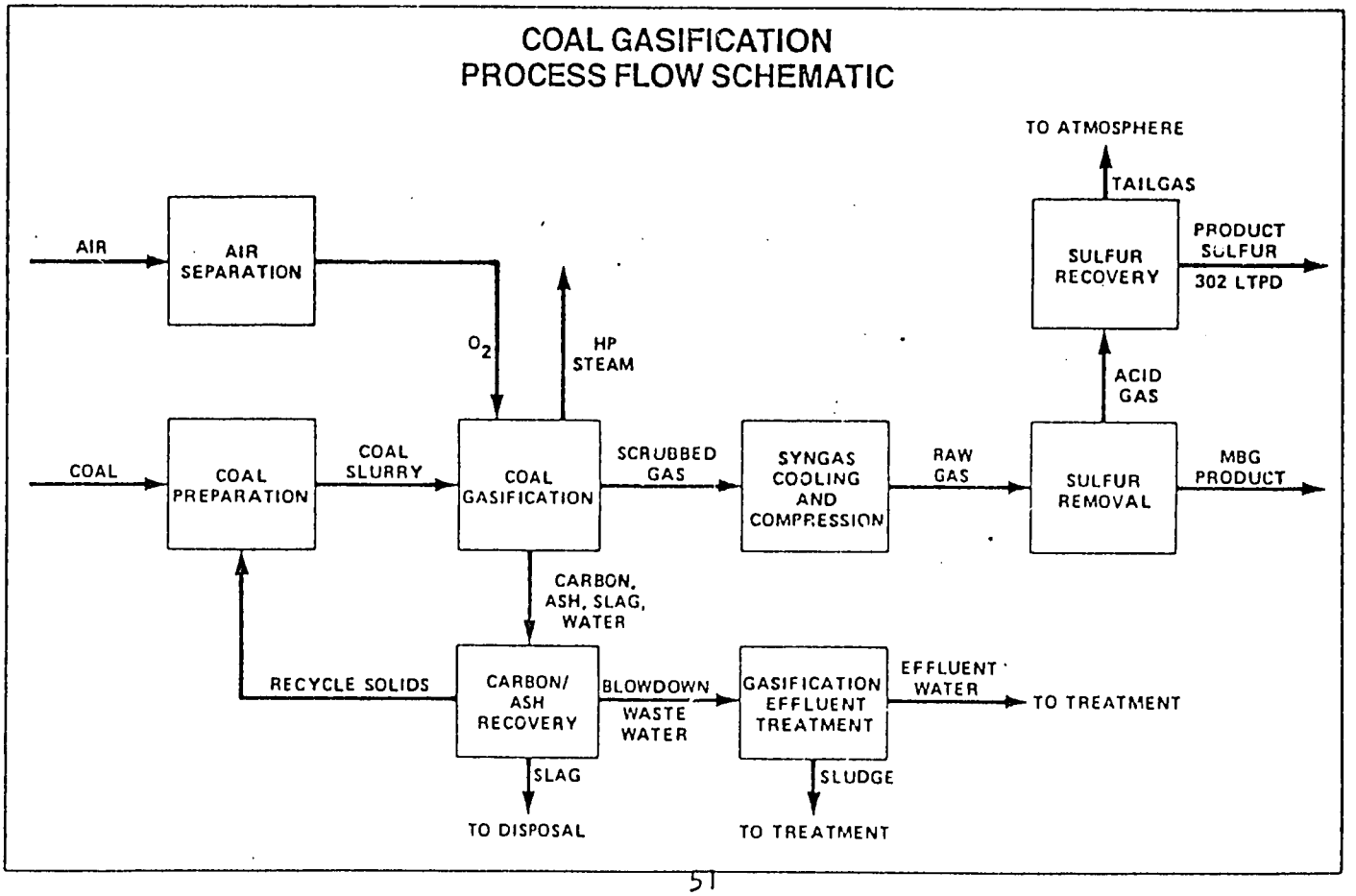
MEDIUM BTU GAS PRODUCTION

Coal gasification, as shown on Figure 1, is essentially the reaction of coal, water, and air or oxygen at high temperature to produce a coal gas. When the source of oxygen is air, the gas produced has a heating value of approximately 100-150 Btu/SCF and is called low Btu gas (LBG). When the source of oxygen is relatively pure, the gas produced will have a heating value of 250-400 Btu/SCF and is called medium Btu gas (MBG). The major constituents in the product gas are carbon monoxide, hydrogen and carbon dioxide with varying quantities of methane depending on the gasification technology employed.[1]

A variety of gasifiers as shown on Table 1 are presently available or under development for the gasification of coal. There are three basic gasifier types: fluidized bed; fixed bed; and entrained flow. The selection of the proper gasifier is critical to the technical and economic success of a project. Some gasifiers are applicable to specific types of coals, while others can be applied to a wide range of coal, with varying economic incentives. Fixed and fluidized bed gasifiers are generally employed for highly reactive coals, while entrained bed gasifiers may be used for less reactive and caking coals. Several of these gasifiers are already in commercial operation, while others are considered near commercial in view of their development status.

In addition to the central gasifier unit, the gasification process requires a front-end coal handling and preparation unit. For the production of medium Btu gas, an air separation plant would also be required. Gas cooling and carbon-ash scrubbing typically follow the gasifier unit. Ammonia would be produced by stripping the wastewaters formed in the scrubbing and cooling of the raw gas. For the removal of sulfur compounds from the raw gas (primarily H_2S and COS) and recovery of elemental sulfur, conventional technology similar to that in use in petrochemical installations

Figure 1



(such as a Selexol and Claus-SCOT combination) would follow the gasifier unit.

POTENTIAL USES OF MBG

Beaver Project

Use of the MBG in the generation of electricity and the production of alternate fuels and by-product chemicals is the approach presently being studied as the Beaver Coal Gasification Project by the Portland General Electric Company in conjunction with Ebasco Services Incorporated and Procon, Inc. The process concept is illustrated on Figure 2. The Beaver project would employ a Westinghouse coal gasification process for the production of 120 billion Btu per day of MBG for use at Portland's existing 600 MW Beaver combined cycle generating station. The MBG can also be used for the production of methanol, synthetic natural gas (SNG), and 300 MW of electrical power. The present feasibility study envisions a capacity of approximately 11,000 TPD of Alaskan or Wyoming subbituminous coal, with a conversion efficiency of coal to electricity at the busbar of about 33 percent.[2] This is about the same as for a conventional direct coal-fired power plant employing pollution control equipment. The major facilities which require development include coal receiving and storage, solid waste disposal facilities, coal gasification, and methanol units.

In this concept, MBG produced in the gasification units would be available at approximately 300 psig as fuel for the Beaver combined cycle plant or, alternatively, as feed for the methanol synthesis unit after the appropriate treatment and compression. About half of the 120 billion Btu/day of MBG produced by the gasification units would be used to synthesize 1750 TPD methanol and 10 billion Btu/day SNG. The remaining 60 billion Btu/day of MBG would then be available for the production of 300 MW of power.[2]

The conceptual design for the Beaver facility permits independent operation and internal optimization of the coal

Table 1

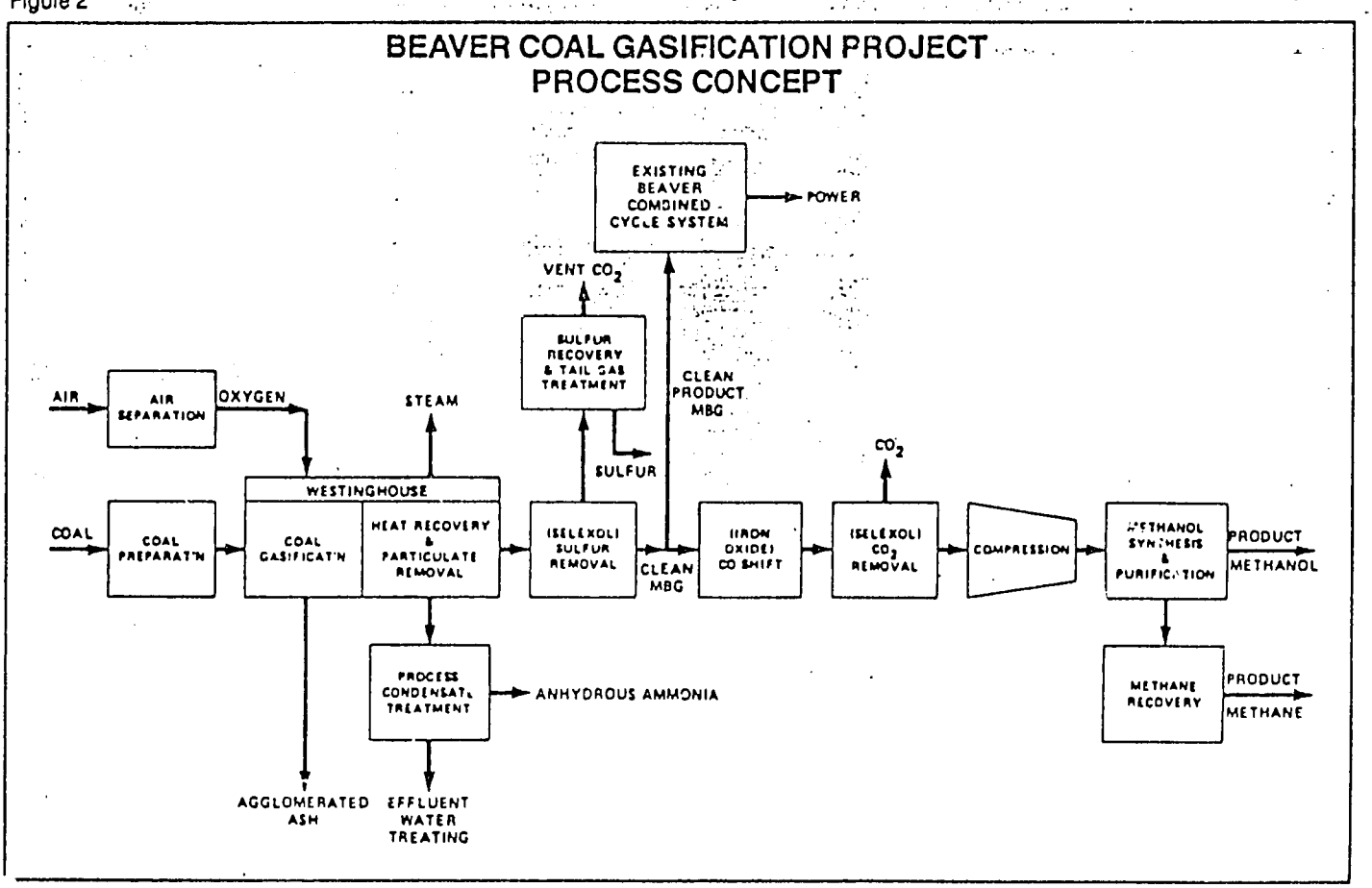
CURRENTLY AVAILABLE COAL GASIFICATION SYSTEMS

ENTRAINED BED
- TEXACO
- KOPPER–TOTZEK
- SHELL–KOPPERS
- BABCOCK & WILCOX
- SAARBURG–OTTO

FLUIDIZED BED
- WESTINGHOUSE
- WINKLER

FIXED BED
- LURGI
- BRITISH GAS COUNCIL (SLAGGER)

Figure 2



gasification units, the methanol synthesis unit, and the combined cycle generating plant. In this way the coal gasification plant would avoid abrupt changes in operating conditions thereby minimizing maintenance costs and loss of service. In effect, operation of the methanol unit provides the capacity to absorb diurnal and seasonal demand swings on the combined cycle plant and allows the gasification facility to operate at base load.

The methanol plant would be load following inversely to the combined cycle plant and would be operating at full design capacity when the combined cycle plant draws MBG at a rate of 60 million Btu/day. When the electricity demand peaks and most of the MBG would go as fuel for electricity production, the methanol unit could be turned down to 20 percent or less capacity. The economic justification for this arrangement is based on the relative size of the capital investment for each of the plant segments. About 85 percent of the total investment represents the coal gasification and support facilities, while about 15 percent or less is for the methanol plant. Figure 3 illustrates the beneficial effect that methanol production and price can have on the cost of the generated electricity.[1]

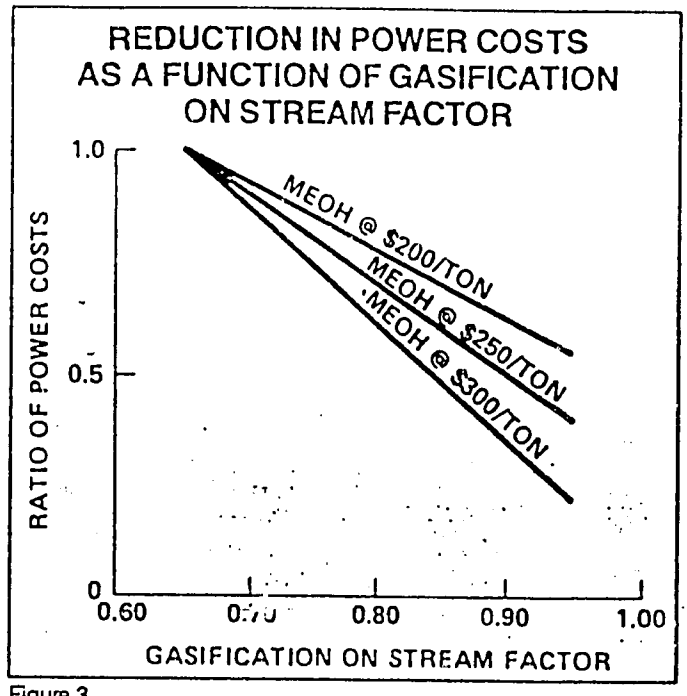
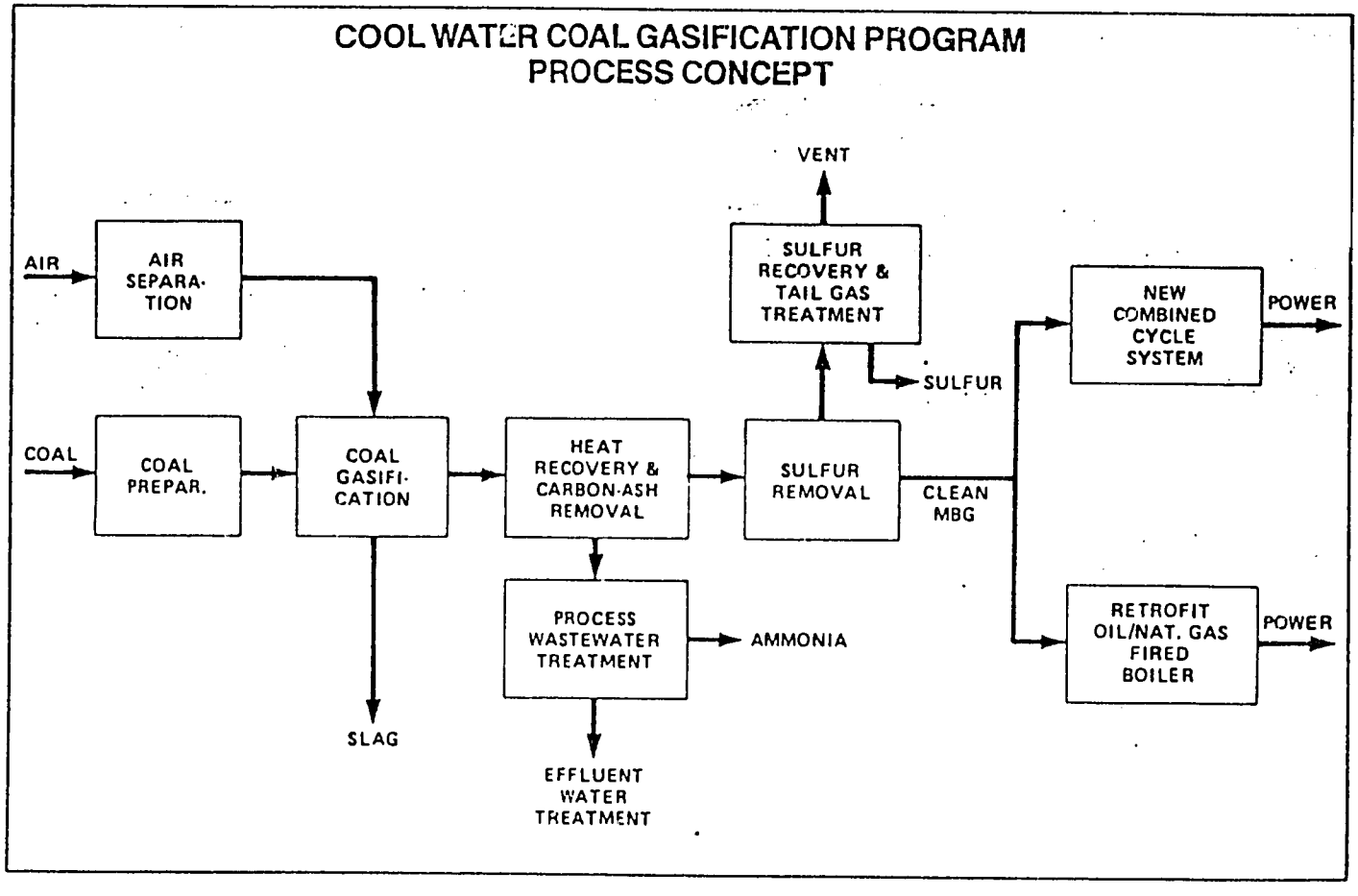


Figure 3

Cool Water Coal Gasification Program

The Cool Water project, presently under construction near Barstow, California, is sponsored by a consortium of Southern California Edison (SCE), Electric Power Research Institute (EPRI), Texaco and others. It is intended to demonstrate the effectiveness of an intergrated coal gasification combined cycle generation arrangement. Utilizing the Texaco Coal Gasification Process, the demonstration facility will process 1000 TPD of Western coal. Figure 4 depicts the Cool Water process concept. As with the Beaver project, MBG is produced from coal and purified of carbon-ash and sulfur. While the MBG is produced primarily for the purpose of supplying a combined cycle system, flexibility is provided in that MBG may also be burned in a conventional oil/natural gas-fired boiler.

Figure 4



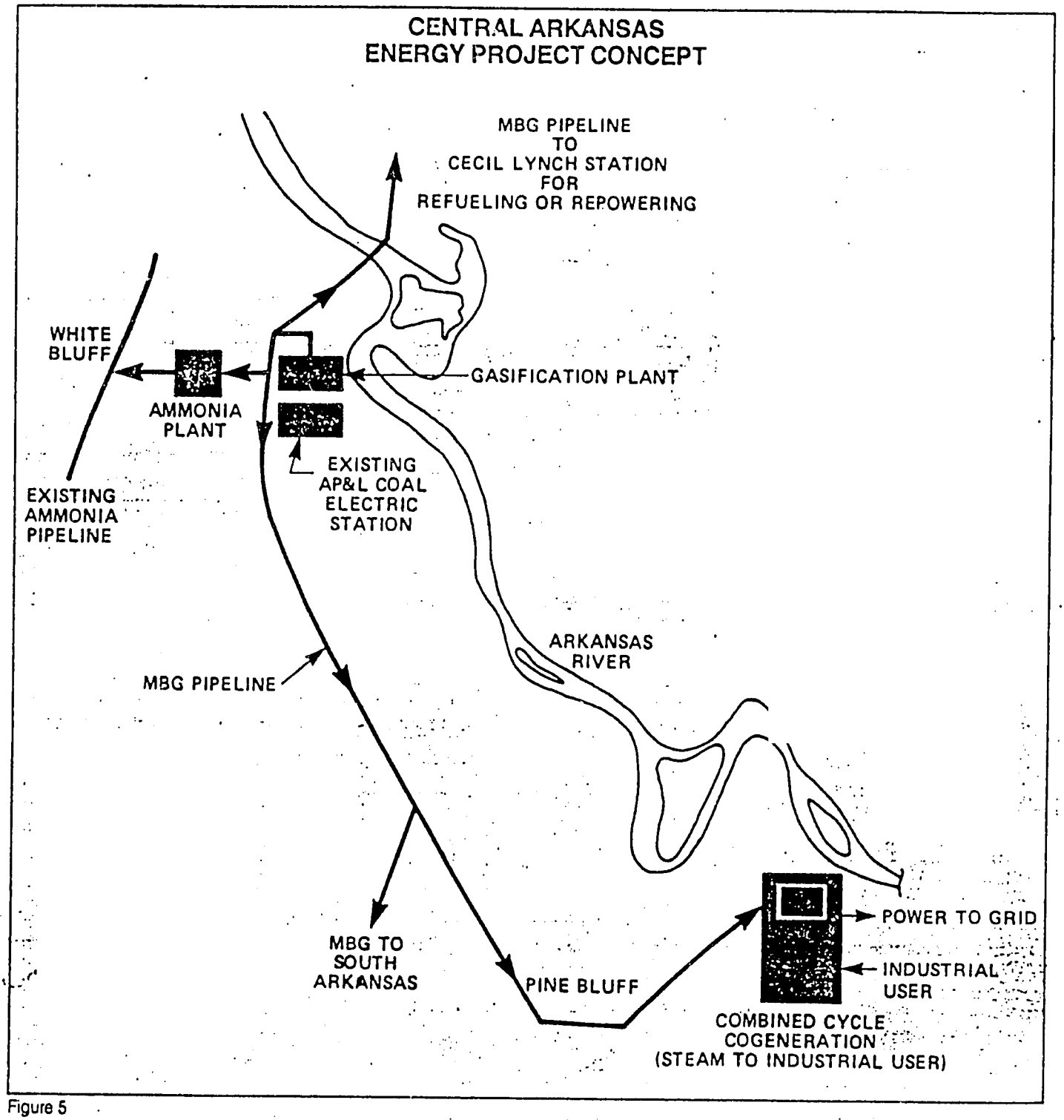


Figure 5

The facility is to be situated adjacent to SCE's existing Cool Water 600 MW power plant. New combined cycle gas and steam turbine components will produce approximately 100 MW of net electrical power. One of SCE's existing generating units however will be retrofitted to burn MBG as part of the test program. The arrangement is such that the gasification facility may be operated in either a base loaded or load following mode.[3] The Cool Water plant is designed to be an integrated coal gasification combined cycle facility. The two sections will share cooling towers and the boiler feedwater systems. Plant control will be centralized on an integrated control panel.

Central Arkansas Energy Project

Additional flexibility may be illustrated with the introduction of Arkansas Power and Light Company's concept of a central coal gasification facility utilizing pipelines to feed MBG to combined cycle cogeneration plants for "over the fence" sale of steam and electricity. The feasibility of this concept, shown on Figure 5, is presently being addressed in a study undertaken by Arkansas Power and Light Company (AP&L) in conjunction with Ebasco Services Incorporated. Coal would be gasified in a central coal gasification facility to produce MBG, which could be pipelined up to approximately 200 miles away. Combined cycle cogeneration

plants would be located at the end-of-lines, situated to provide process steam and electricity to industrial users. Electricity produced for return to the AP&L grid would be a secondary product in this arrangement. Arkansas Power & Light's concept incorporates, on an optional basis, the production of ammonia and the use of the MBG for the refueling or repowering of an existing station to allow base loaded operation of the gasification facilities.[4]

Under the AP&L concept, the central coal gasification facility would be owned by the utility; the end-of-line combined cycle cogeneration plants would be owned by an unregulated subsidiary or subsidiaries; the ammonia facility would be owned by a chemical company; the industrial process steam would serve various industries; while the AP&L grid would represent a means of marketing excess cogenerated electricity.[4]

Arkansas Power and Light Company sees the coal gasification end-of-line combined cycle cogeneration concept, shown on Figure 6, as an opportunity for electric utilities to expand their business into a multiple product line and to significantly increase utility revenues. Utilities may also benefit from the AP&L concept to the degree that its implementation would be responsible for the retention of existing electricity revenues collected from industries having the potential to independently develop conventional cogeneration facilities. Additionally, implementation of AP&L's concept would diminish the need for a central electric generating station and would provide a utility with new generating capacity distributed through its area of service.

Coal Gasification—The Basic Building Block

The optimum role of coal gasification in power production on a case-specific basis is dependent on a number of variables. Among these are: local and regional demand for potential energy products and by-products; financial capabilities and goals of the participating utility and industry(ies); steam profile and demand swings of potential participants; and potential regulatory and statutory constraints/incentives. Coal gasification, however, as illustrated on Figure 7, is the basic building block in an array of opportunity. Beginning with coal gasification as the essential first step, developers hold the options to co-produce:

MBG—as a fuel source for centralized or decentralized cogeneration or conventional power production

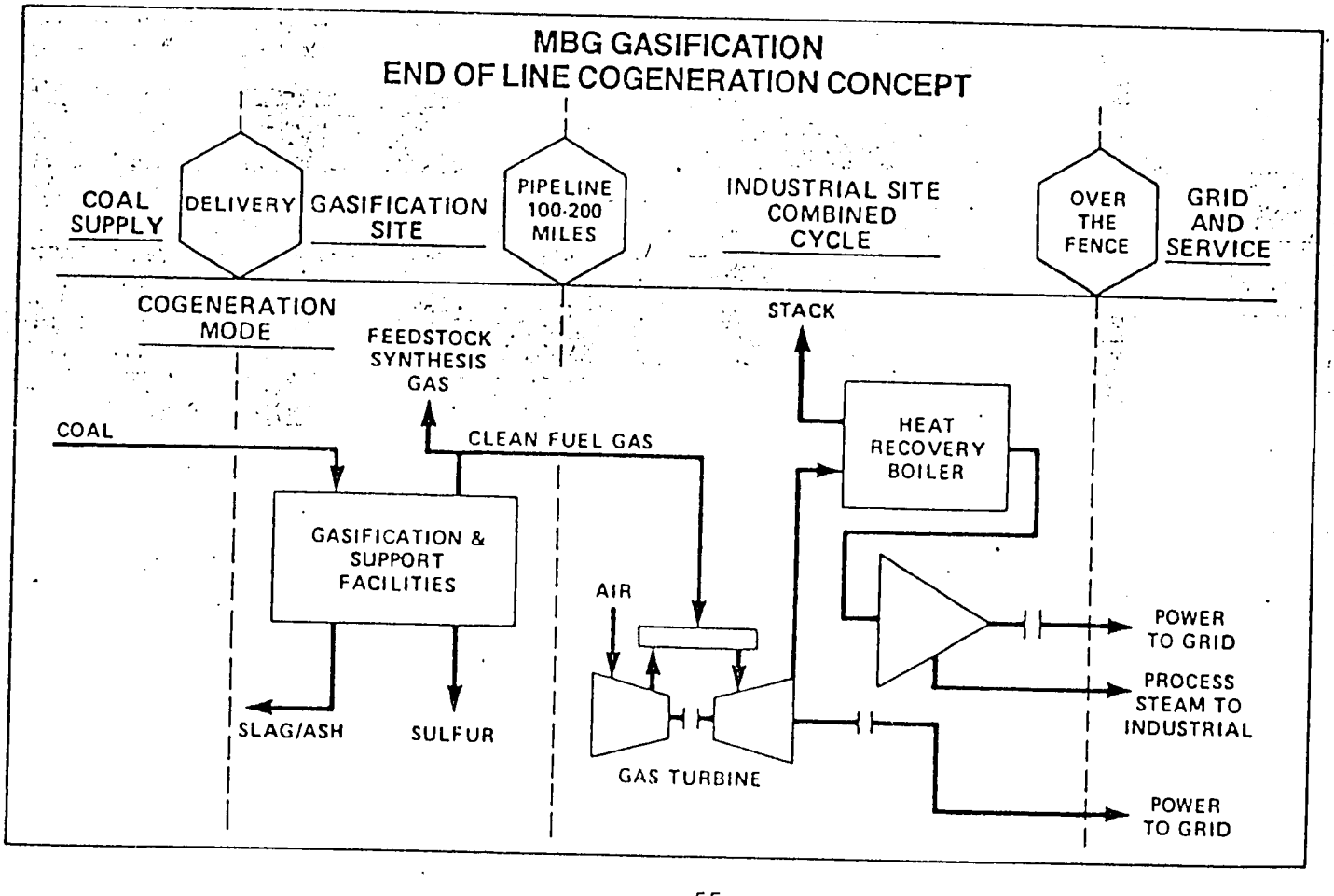
Methanol—as a chemical feedstock or fuel source for power production or transportation. Co-production of methanol allows for base loaded operation of the gasification facility

Synthetic Natural Gas—as a fuel source or chemical feedstock

By-Product Chemicals—such as ammonia, hydrogen and sulfur, which increase the economic attractiveness of installations through the sale of these marketable commodities

Steam and Electricity—when combined cycle cogeneration is included in the configuration, steam and electricity may be produced at rates economically competitive with the direct coal firing alternative.

Figure 6



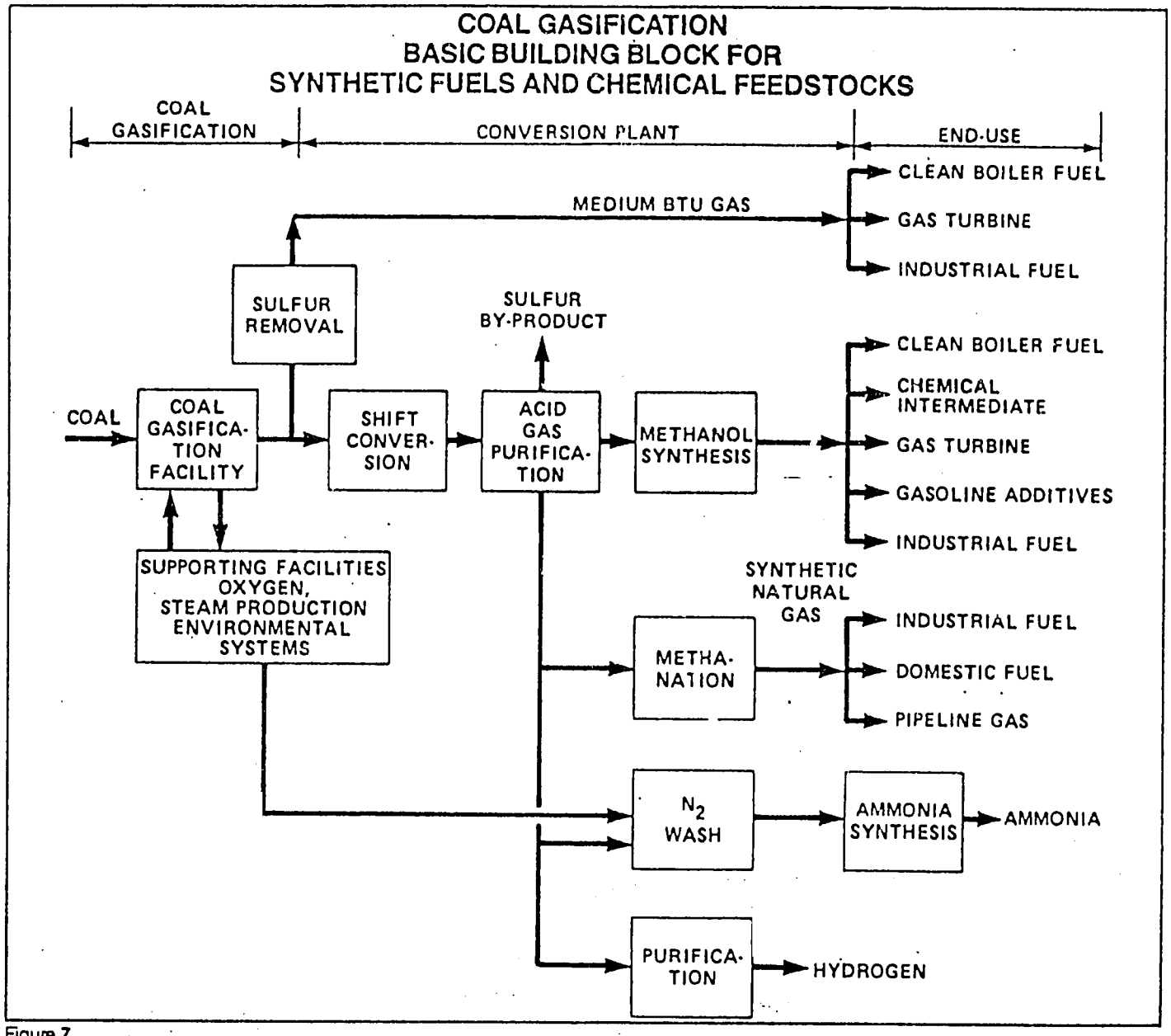


Figure 7

ECONOMICS OF COAL GASIFICATION

Cost estimates for both coal gasification plants and direct coal fired stations vary substantially according to the type of technology, the location and the source of the information. Generally speaking, however, most studies published to date indicate that both operating and capital cost of a number of second generation gasification technologies currently entering commercialization phases will be lower than direct coal fired generation costs once the technologies are fully developed commercially. Economics favorable to the coal gasification route have been presented in detail by EPRI as early as 1978.[5] A recent update[6] has confirmed these findings which indicate, as shown on Table 2, that the cost of electricity using the coal gasification combined cycle concept would be the equivalent of or less than the cost using a direct coal fired plant.

Ebasco studies in this area, which have been based on present day technology without the design refinements that can be expected as commercial exploration of the new technology proceeds, have indicated that operating costs

Table 2
ELECTRIC POWER COST AT
70 PERCENT CAPACITY FACTOR
GASIFICATION COMBINED-CYCLE POWER SYSTEMS
WITH 2400°F GAS TURBINES

GASIFIER	OXIDANT	TOTAL CAPITAL REQUIREMENT $/KW**	30-YEAR LEVELIZED COST OF ELECTRICITY **
LURGI	AIR	965.27	56.24
BGC SLAGGER	OXYGEN	770.46	44.53
FOSTER WHEELER	AIR	749.37	43.69
COMBUSTION ENGINEERING	AIR	907.92	52.13
TEXACO	OXYGEN	871.47	49.68
COAL-FIRED PLANT WITH FGD SUBCRITICAL 2400/1000/1000		875.12	56.25

** MID-1978 DOLLARS
** COAL COST EQUALS $1/10^6$ BTU ASSUMING 6 PERCENT/YEAR INFLATION
SOURCE: ELECTRIC POWER RESEARCH INSTITUTE, REPORT NO. AP172, FEBRUARY 1981

of coal gasification combined cycle plants are comparable with those of a direct coal fired station and that capital costs are higher. Despite this, Ebasco believes that current coal gasification combined cycle designs can frequently allow a utility to generate electricity at a lower cost than from a direct coal fired plant of similar capacity. This is because of fundamental differences between the nature of the plant's configurations which tend to favor the coal gasification approach. These differences can be important and must be recognized.

Availability and Capacity Factor

The availability of a large (600-800 MW) direct coal fired station is generally in the area of 75 percent. Capacity factors are usually five points lower.

Conversely, the availability of a typical coal gasification combined cycle plant of comparable capacity is substantially higher (typically about 90 percent). This is because plants of this capacity are multi-train, with sufficient redundancy of equipment to allow full plant production while following a regular maintenance program.

Of course, high availability is not necessarily an advantage if the gasification plant is not base loaded, or if other factors present a fluctuating electricity demand. While gasification plants are capable of following a varying load, Ebasco believes that alternate modes of operation that maximize the capacity factor of the gasification plant can result in more favorable economics.

Financing

Various scenarios have been suggested that would result in utility ownership of only the combined cycle element of the facilities. The gas production plant could be owned and operated by others. This means that the utility could acquire additional generating capacity for the relatively modest capital outlay of $300-400/kW (current pricing). This approach can be extended still further in cogeneration applications to the point where utility ownership is limited to the gas turbine, with resultant additional savings of about 30 percent.

Tax Credits

The issue of energy tax credits is far from clear, but it appears that part, at least, of the coal gasification combined cycle plant should qualify for tax credits additional to those applicable to a direct coal fired plant.

Cogeneration Leverage

Coal gasification combined cycle economics are greatly enhanced in cogeneration situations because of the vastly increased ratio of electricity to steam from a gas turbine combined cycle configuration as compared to a direct fired cogeneration station. Typically, 300 MW of electricity can be cogenerated with a 600 psi steam output of about 1,000,000 lb/hr. This compares with a gross output of typically 30 MW for a comparable direct fired cogeneration installation. Furthermore, with a pipeline concept similar to the Arkansas concept, cogeneration economics are favorable even for relatively small steam requirements, for example 250,000 lb/hr.

Transmission Line Savings

Transmission of power from a large central station to demand centers can be expensive particulary if there are right-of-way restrictions. The coal gasification combined cycle configuration allows the option of locating combined cycles close to the users and piping the gas in from a central gasification plant, which can be up to 200 miles away. Combined cycles are very clean and relatively unobtrusive. Furthermore economical power generation can be achieved with relatively small individual plants (say 120 MW each)—economies of scale with combined cycle plants are not particularly significant above this capacity.

ENVIRONMENTAL COMPARISON

The use of MBG for the production of power in coal gasification combined cycle arrangements such as those described above offers advantages over direct coal firing, with regard to environmental impact. This may be demonstrated through a comparison of gaseous and liquid emissions to the environment, characteristics of solid wastes generated for disposal, and water withdrawal requirements.

The following comparison of coal gasification to direct coal firing assumes the selection of a high temperature, entrained flow gasifier. As discussed elsewhere, this type of gasifier is the most environmentally attractive due to the nature of its emissions.[7] Further, the following comparison is based on equal coal consumption rates, 10,000 TPD of Illinois No. 6 coal. While the various gasifiers require somewhat greater or lesser amounts of coal to produce equivalent amounts of energy, in general, coal gasification combined cycle systems require the same rate of coal consumption per MW produced as would be required by a direct coal fired plant.

Air Quality

Table 3 compares typical atmospheric emissions occurring from a coal gasification combined cycle system and a direct coal fired power plant, unitized to a coal throughput rate of 10,000 TPD. These are generic estimates based on our experience with a number of facilities. The actual numbers would vary according to the specific coal characteristics and process arrangements. For the puposes of this comparison the SCOT process has been assumed for treatment of tail gases in the gasification section. The most significant difference in this comparison is the low output of SO_2 from the coal gasification combined cycle arrangement. This is due to the ability of the process to remove sulfur contaminants from MBG as saleable, elemental sulfur. Secondly, NO_x emissions would be reduced by the stripping of ammonia from MBG after gasification and by saturating the gas with water vapor and preheating it prior to feeding to

Table 3

COMPARISON OF TYPICAL ATMOSPHERIC EMISSIONS (Tons Per Year)

	SO_2	NO_x	TSP	CO	H_2S	COS
COAL GASIFICATION FACILITY (SULFUR PROCESSES)	320	620	–	–	–	–
METHANOL SYNTHESIS (CO SHIFT)	20	250	–	200	2	15
COMBINED CYCLE	90	4,500	–	800	–	–
TOTAL COAL GASIFICATION – COMBINED CYCLE SYSTEM	430	5,370	–	1,000	2	15
DIRECT COAL FIRED PLANT	34,500	29,700	1,190	1,700	–	–

the combined cycle section. Total suspended particulate (TSP) emissions have been shown for stack sources only. Fugitive dust emissions have not been shown since, for either type of plant, these would be predominantly a function of coal consumption rate and emission controls built into the coal handling and preparation equipment.

Water Intake/Wastewater Discharge

Table 4 shows typical water withdrawal requirements and wastewater discharge quantities for both the coal gasification combined cycle arrangement and a direct coal fired plant. These numbers are subject to a number of variables however such as coal characteristics and intake water quality. While the coal gasification combined cycle arrangement typically consumes and discharges greater volumes of water, this may be minimized by incorporating zero discharge and wastewater reuse technology into the plant design.[7] Unitized to 10,000 TPD coal consumption, the Cool Water design, at about 11,000 gpm/10,000 TPD coal, would be comparable to a direct coal fired plant's water requirement.

Table 4

COMPARISON OF TYPICAL WATER REQUIREMENTS AND WASTEWATER DISCHARGE(gpm)

	DIRECT COAL FIRED PLANT	COAL GASIFICATION COMBINED CYCLE
WATER INTAKE	10,000–15,000	19,000
CONSUMPTION	2,500–12,000	9,500
WASTEWATER DISCHARGE	2,500– 7,500	9,500

Water quality characteristics of the discharge are also subject to a number of variables such as coal type, process arrangements, effluent limitations, and hydrology and water quality existing in the receiving water body. It is widely recognized, however, that high temperature, entrained flow coal gasification wastewaters can be treated to acceptable levels using conventional control technology.[7,8,9]

Solid Waste

Approximate quantities of solid waste generated for disposal from both coal gasification facilities and direct coal fired power plants are given in Table 5. The largest quantity of waste generated in coal gasification comes from slag. In high temperature gasifiers, slag is produced when molten, unreacted portions of the coal are quenched in water to form hard, rock-like particles. A number or process sludges are also produced in coal gasification facilities from water pretreatment, wastewater treatment, and maintenance activities.

Table 5

COMPARISON OF TYPICAL SOLID WASTE QUANTITIES (Tons Per Year)

	DIRECT COAL FIRED PLANT	COAL GASIFICATION COMBINED CYCLE
FLY ASH	365,000	NA
BOTTOM ASH	90,000	NA
FGD SLUDGE	490,000	NA
COAL SLAG	NA	540,000
PROCESS SLUDGES	NA	150,000
BIO-OXIDATION ASH	NA	1,000
TOTALS	945,000	691,000

The quantity of solid waste generated in a coal gasification plant is typically less than that generated in a direct coal fired plant, and the quality of the leachate is quite inoccuous. Tennessee Valley Authority addressed slag leachate quality in the Final Environmental Impact Statement prepared for their proposed Murphy Hill coal gasification project.[10] TVA found, based on a number of studies, that slag is nonhazardous when subjected to the EPA EP toxicity test (40 CFR Part 261). Recent studies by Ebasco, addressing high temperature, entrained flow gasification processes, indicate that the process sludges would similarly be nonhazardous in nature. Only low volume process catalysts and oily wastes are potentially hazardous and these may typically be removed from the plant site for resource recovery or disposal.

CONCLUSIONS

The production and use of medium Btu gas for power production and alternative fuels and/or chemical feed

stocks offer utilities a viable option to direct coal firing. Th concept would reduce some of the traditional environme tal concerns of direct coal firing and open a number of bus ness opportunities that would otherwise be unavailabl With respect to economics, the coal gasification concep particularly as it applies to the combined cycle cogener tion mode for power production, appears on the verge competitiveness with direct coal firing. Furthermore, it is e pected to be generally competitive with direct coal firin once commercialization proceeds and design refinement are incorporated. The economics, of course, would still b dependent on case specific circumstances.

In light of these benefits and the additional security of a uninterruptible source of energy, serious consideration the coal gasification approach to power generation is es sential and a very responsible investment in the future secu rity of the electric utility industry.

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8. R.G. Luthy, Carnegie-Mellon University; "Treatment c Coal Coking and Coal Gasification Wastewaters; Journal Water Pollution Control Federation, Marc 1981.
9. R.G. Luthy, et al., Carnegie-Mellon University; "Re moval of Organic Contaminants from Coal Conversio Condensates;" Fifty Fourth Annual Water Pollutio Control Federation Conference, Detroit, October 8 1981.
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Annex B

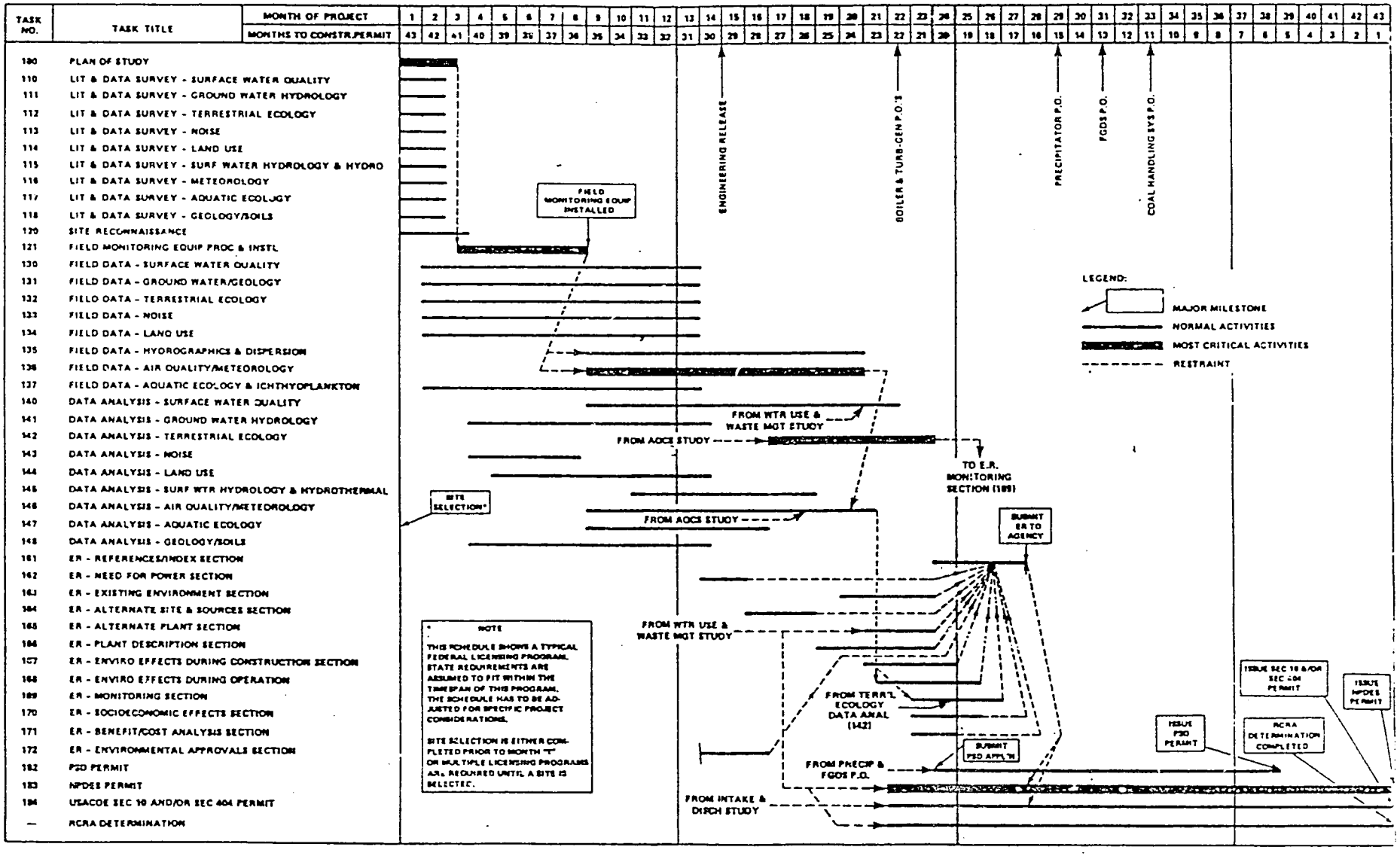
This Annex B shows the typical time schedule for obtaining permits from Federal regulatory agencies for the construction of a power plant in the U.S. The total elapsed time is 43 months, or nearly three and a half years.

The schedule does not include the time for obtaining state and local clearances, some of which can be obtained simultaneously, but will inevitably add to the total elapsed time.

The purpose of this submission is to show how long it would take to obtain permission for a coal-fired power plant utilizing coals, for example, from the U.S. midwest. Such coals can be utilized in Panama with no regulatory processing delays. The builders of the proposed Panama facility would be committed, however, to achieving environmental standards in Panama equal to or better than those required in the U.S.

Annex B

Ebasco Services Incorporated
TYPICAL FEDERAL* LICENSING SCHEDULE FOR A COAL FIRED POWER PLANT



ANNEX C

REPORT ON THE TRANS-PANAMA PIPELINE SYSTEM

Prepared by Morrison-Knudsen International Company, Inc.

April, 1982

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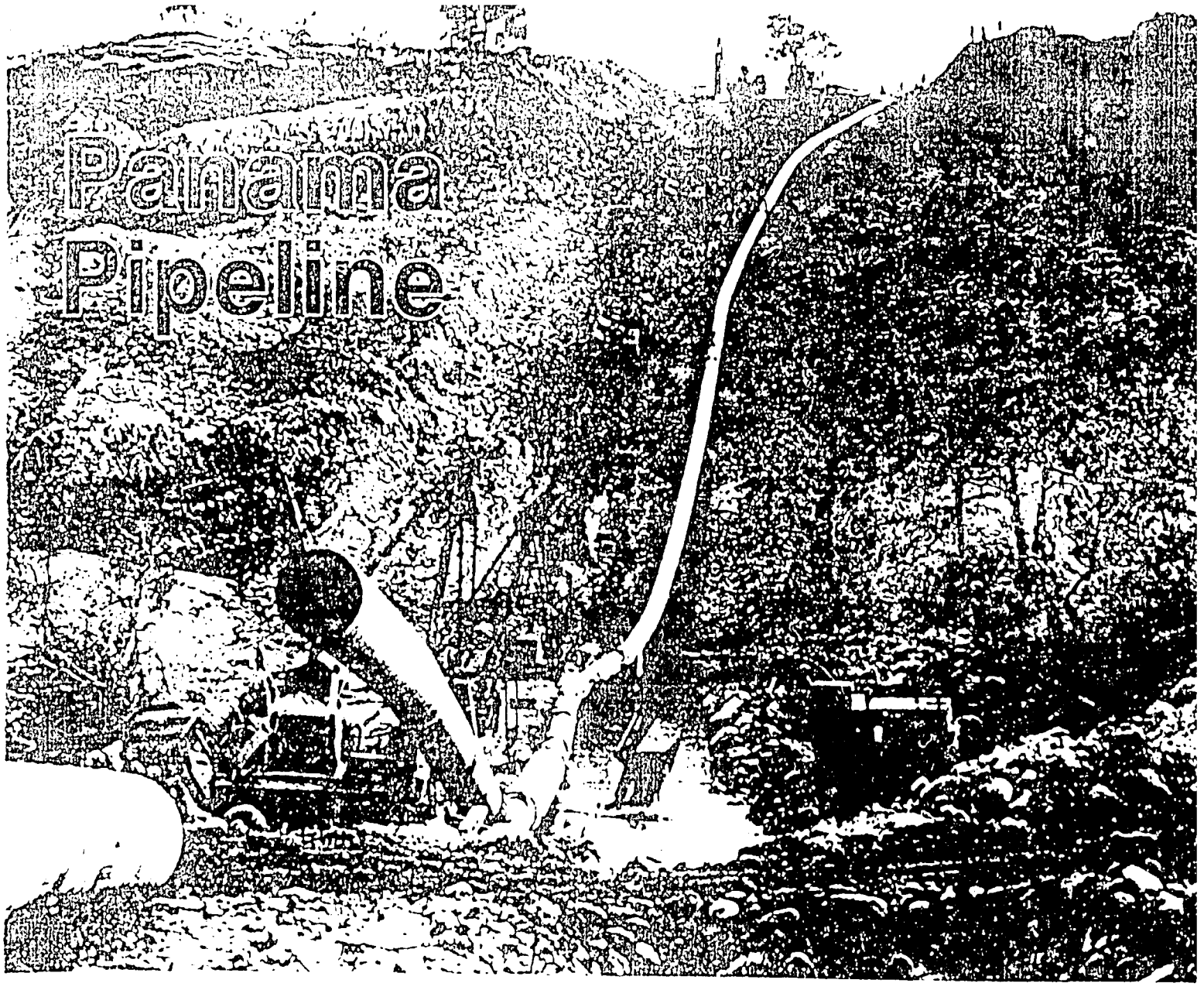
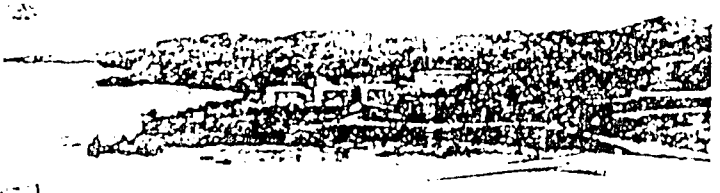
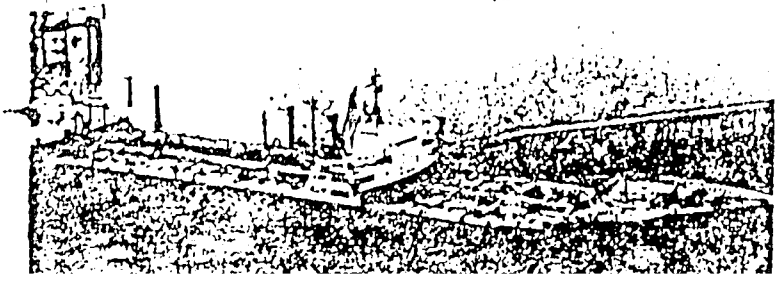
Panama Pipeline







IN 1914, A TRANSPORTATION milestone of international significance occurred with the opening of the Panama Canal, a 50-mile long navigable waterway across the Isthmus of Panama that greatly shortened shipping routes between the Pacific and Atlantic oceans.

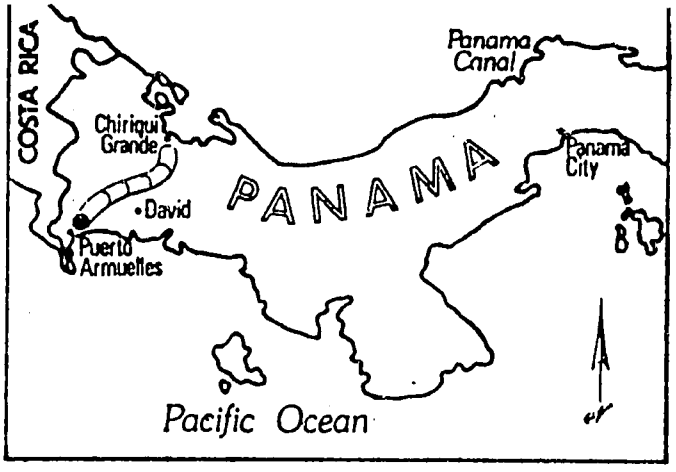
Now, nearly seven decades later, a new transportation artery of a vastly different type, but of similar economic importance, is under construction in the Republic of Panama, some 220 miles west of the Panama Canal. It is known as the Trans-Panama Pipeline System and will reduce the time and cost of moving crude oil from the North Slope of Alaska to refineries along the Gulf Coast of the United States. At present, large tankers bring the crude from Alaska to Panama where it is transferred to smaller tankers, taken through the Panama Canal and on to the refineries.

The Trans-Panama Pipeline System is a development of Petroterminal de Panama, S. A., a joint venture of the Panamanian government with Northville Industries Corp., of Melville, New York, and CBI Industries, Inc., of Oak Brook, Illinois.

Morrison-Knudsen International Company, a wholly owned Morrison-Knudsen subsidiary, is performing design, procurement and construction services on the approximate $170-million project in association with the Panamanian firm of Constructora Urbana, S.A., under a contract awarded in March of 1981. Major features of the system include:

approximately 130 kilometers (80 miles) of 40- and 36-

ABOVE: [illegible] pipe is headed for [illegible] of [illegible] scale



ABOVE, LEFT, map shows pipeline route across Panama some 350 kilometers west of Panama Canal. ABOVE, pipe sections and steel plate for storage tanks are stockpiled at Chiriqui Grande. BELOW, tropical rain forest borders Chiriqui Grande port on the Atlantic.

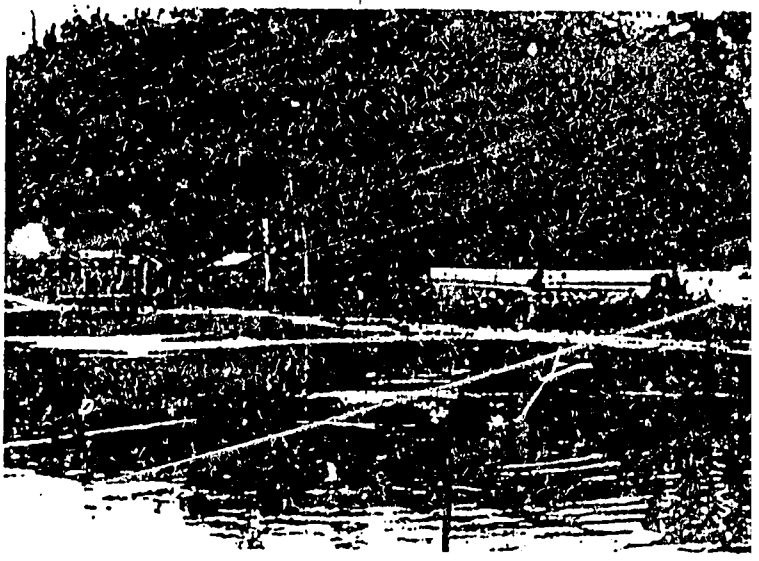
inch-diameter pipeline with a maximum design flow of 800,000 barrels per day, reaching from Puerto Armuelles on the Pacific side of the isthmus to Chiriqui Grande on the Atlantic side.

—all-new oil storage and tanker loading facilities, as well as extensive support structures at Chiriqui Grande.

—pumping stations located at the existing Puerto Armuelles port and at Caldera, which is located along the pipeline route approximately two-thirds of the way between the Pacific and Atlantic sides.

The pipeline and its appurtenant facilities are posing a stern design and construction challenge to forces of the M-K organization. The oil artery route traverses widely varying terrain . . . banana plantations and vast grasslands . . . jungle-clad rain forests with rainfall up to 200 inches a year . . . craggy mountain passes . . . and lowland bogs and mangrove swamps. In addition, there are more than 100 water crossings, including nearly 30 major waterways up to 300 feet in width. In these water areas, the pipeline carries a coat of heavyweight concrete to help provide negative buoyancy.

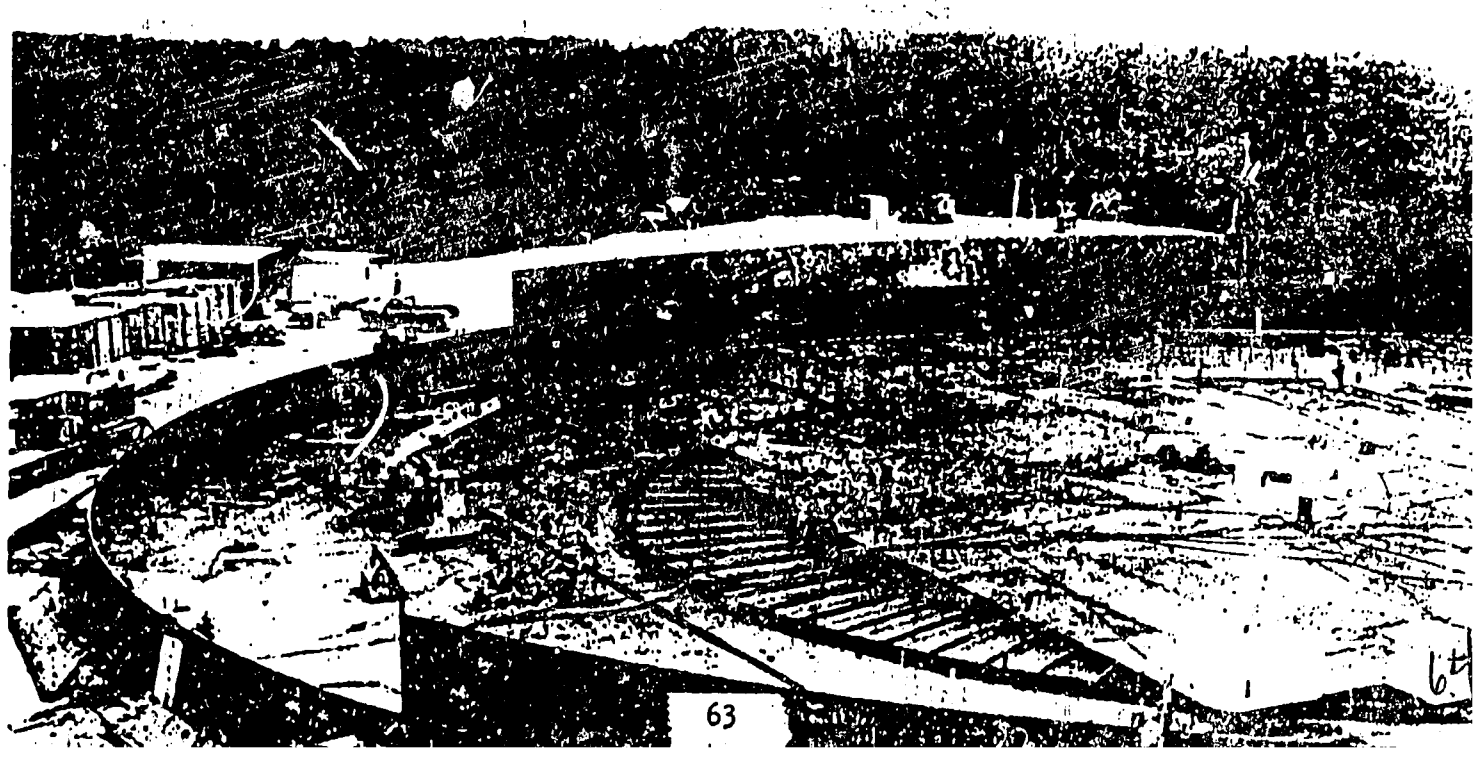
Starting from Puerto Armuelles, the pipeline is of 40-inch diameter and crosses lowland pastures and banana plantations for a distance of some 80 kilometers (50 miles) to the Caldera pump station. Here, the welded steel tube will taper to 36-inch diameter and begin a sharp climb into the rugged Serrania de Tabasara Mountains, reaching an elevation of

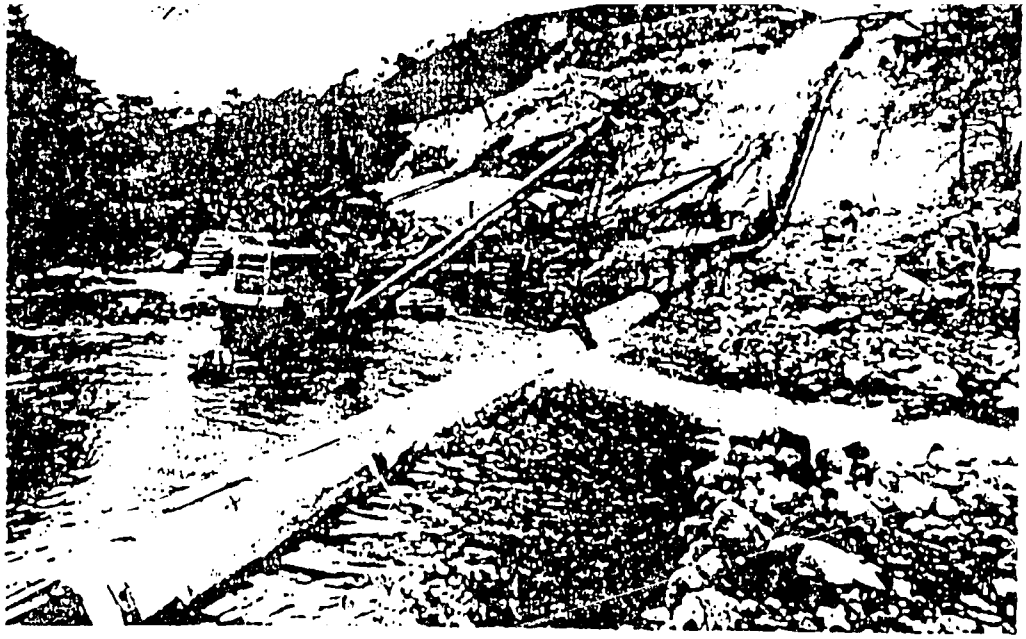


nearly 4,000 feet. The final leg will take the pipeline down the steep mountain range and through swamps and bogs to the marine terminal at Chiriqui Grande. On this downward section to the terminal, oil will flow at a velocity of some 7½ feet per second.

A fleet of well over 250 units of major equipment — among

BELOW, one of three crude oil storage tanks, each with 850,000 barrel capacity, takes shape at Chiriqui Grande. Tanks will feed crude oil to vessels of up to 160,000-ton-deadweight capacity.





ABOVE, pipe section, coated with heavyweight concrete, is lowered into place at river crossing. More than 100 water crossings are required, including 30 major crossings.

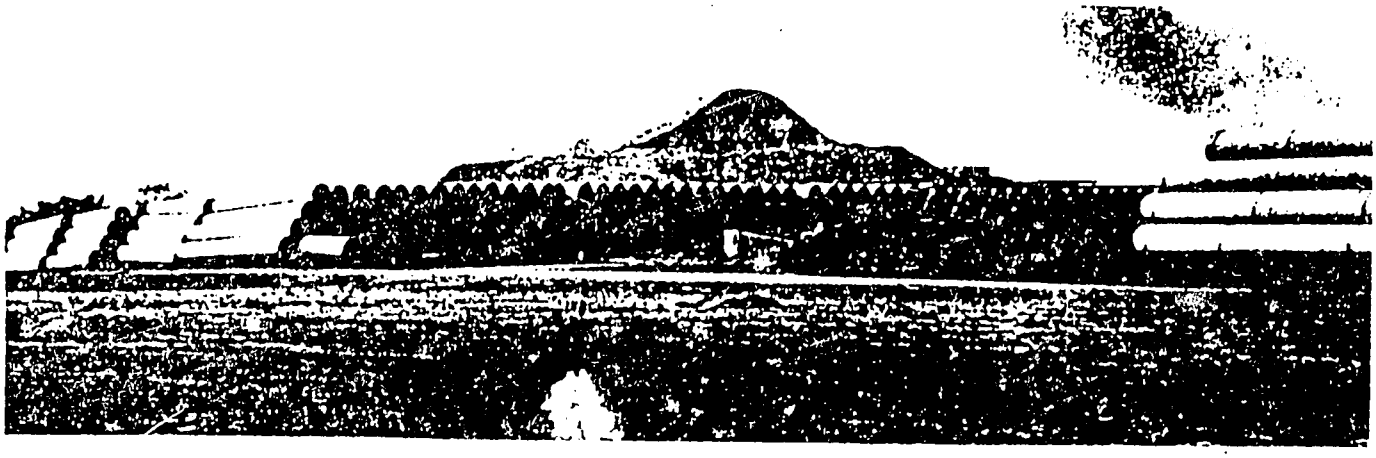
them some 75 crawler tractors, nearly 30 side-boom pipelayers and an assortment of backhoes, loaders and cranes — is advancing on the big job at a number of locations along the route. Working in a fast-paced and well-coordinated procedure, M-KI specialists by early March had prepared more than 100 kilometers of right-of-way, welded more than 90 kilometers of pipe and tayed more than 80 kilometers of pipe.

Along about 30 kilometers of the route where soil conditions permit, the trench is being opened by a bucket-wheel machine. On the remainder of the route and at river crossings, the trench is being excavated by a team of hydraulic backhoes and cranes handling grapples and clams

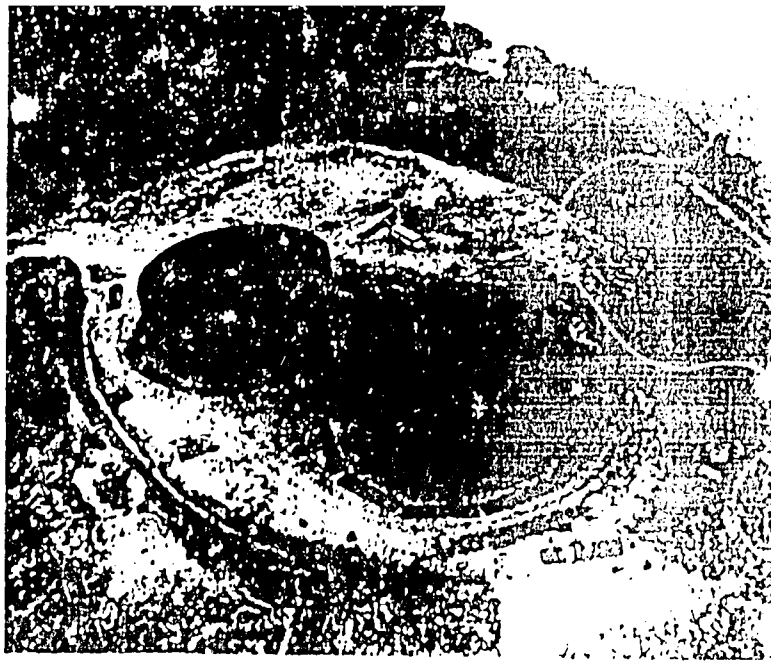
Pipe is being supplied in 40-foot sections, or "joints," most of it to the Pacific side terminal where it is welded into double joints then transported to stockpile areas along the route. From there, the pipe sections — which have wall thicknesses ranging from .312 to .625 of an inch — are hauled to the right-of-way by tractor rigs with self-steering trailers. Some 19 kilometers of pipe are being received at the Chiriqui Grande port and left in single joints for distribution in the mountainous areas where access is limited. In all, some 37,000 tons of pipe are required.

After pipe sections are positioned along the right-of-way, they are shaped by bending machines as required to match the contour of the terrain, joined by welders, then lowered into the trench and backfilled.

At the Chiriqui Grande marine terminal, work is under way by CBI Industries under a subcontract on erection of three crude oil storage tanks with a total capacity of 2.5-million barrels and on three other tanks with a 360,000-barrel capacity for storage of tanker ballast water. The oil tanks are being fabricated on a hillside some 3½ kilometers from the shoreline and 250 meters above sea level to allow gravity flow of oil to awaiting vessels. From the storage tanks, two 36-inch-diameter pipelines will deliver the crude to a shoreline manifold where it will continue via two 36-inch submarine lines out some 1,900 meters offshore to two catenary anchor



ABOVE, pipe is stockpiled at storage yard near city of David. BELOW, LEFT from left (front), Jim Santelli, structures gen. supt., Tony Zatonski, excavation supt., Tex Rix, gen. supt., Gerry Von Sychowski, electrical gen. supt., Lew White, resident design engineer, (back), Joe Bickerson, pipeline general supt., John B. Renwick, project director, W.L. Fox and Fred Caton, project managers, Tommy Derryberry, pipeline gen. supt., Ed Widgeon, manager of project engineering, Darrell Newton, logistics general supt., Doc Kidwell, camps supt.; RIGHT, (front) Frank Collard, camp supt., Lincoln Davis, supt., Bill Dodge, bending supt., (back), Melvin Johnson, bending supt., Henry Jeans, pipeline supt., Supt. Derryberry, James Martin, supt., Bob Person, pipeline general supt. and Ronald Dunn, welding supt.



ABOVE, LEFT, foundation preparation progresses on oil storage tank in background while fabrication of companion tank proceeds in foreground. RIGHT, two of an eventual three ballast storage tanks with combined 360,000 barrel storage capacity take shape at Chiriqui Grande.

leg mooring buoys that are designed to handle tanker vessels up to 160,000-deadweight-ton capacity. The two mooring points — located in 70 feet of water and separated by approximately 1,000 meters — have a designed loading capacity of 120,000 barrels an hour.

All of the offshore pipe is being prepared with corrosion protection and heavyweight concrete at a plant of M-KI and associates at Invergordon, Scotland.

M-KI forces also are installing 30-inch oceanfloor pipelines to bring ballast water from the sea-going vessels to storage and treatment facilities on the shore. Here, oil will be reclaimed from the ballast water and the cleansed water returned to the ocean.

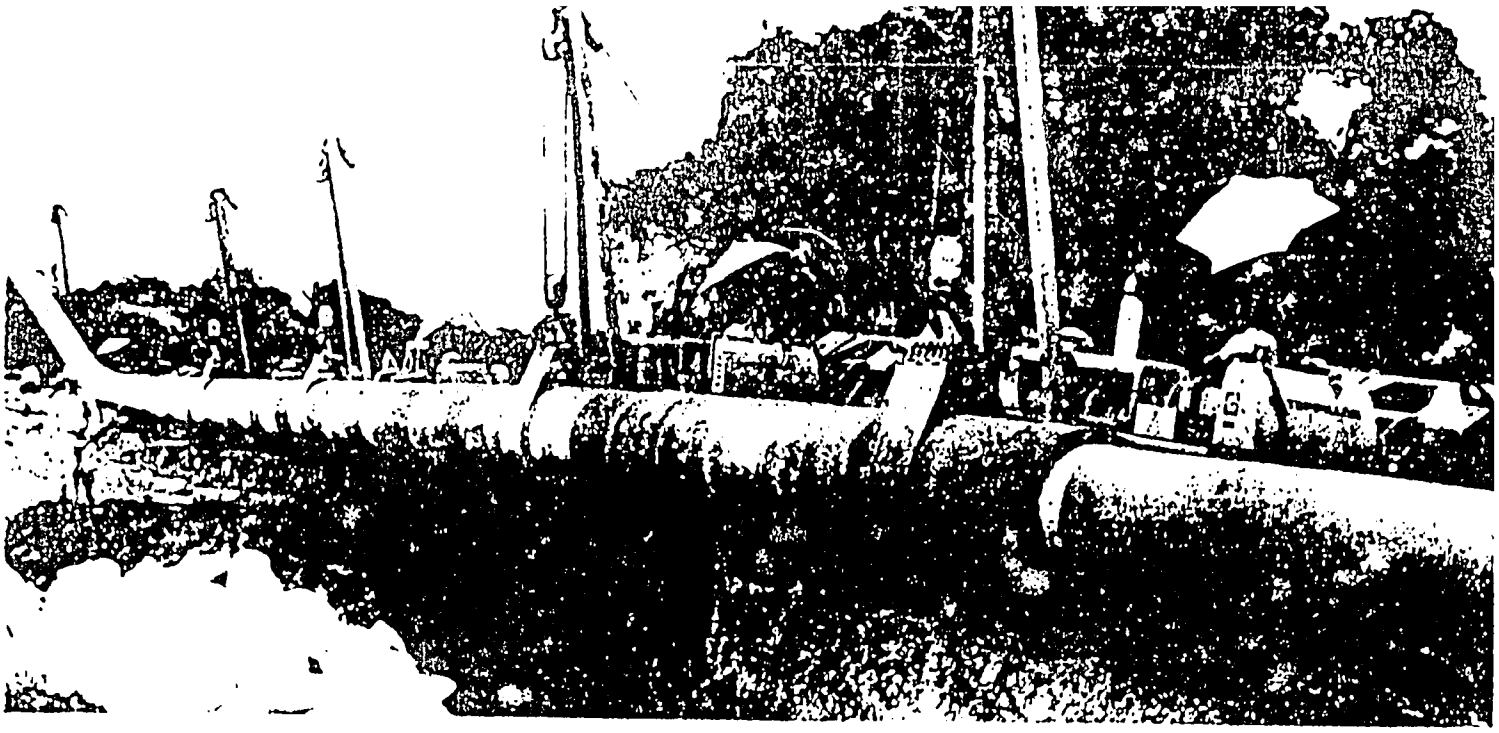
Other major facilities being erected at the isolated Chiriqui Grande site include emergency earthen containment structures for the storage tanks, fire-fighting pipelines and equipment, as well as a permanent dock facility, protective rock causeway and a camp area and airstrip.

Two pumping stations are required to boost the oil to its destination at Chiriqui Grande. One is located at the Puerto Armuelles port which is presently used to transfer oil from large tankers into smaller vessels for transit through the Panama Canal. The other station will be at Caldera at the base of the Serrania de Tabasara Mountains.

Each station will be equipped with four large pumps driven by 5,000-horsepower electric motors. The Puerto Armuelles station will be powered by eight 2,500-kilowatt diesel-fired generators assembled by M-K's Power Systems Division at its Rocky Mount, North Carolina production facility. Power for the Caldera station will come by connecting with existing transmission lines of Panama's electrical utility. To accomplish this, M-KI is constructing a switching station and transmission lines near the station.

John Renwick is in charge of the job for M-KI as project director, assisted by W. L. Fox, construction manager, Ed Widgeon, engineering manager, and R. S. Thorn, general business manager. Design work is being performed by International Engineering Company at its Gulf Coast District office in Houston, under the direction of Richard Barfield as vice-president. Oscar E. Starke is

RIGHT, 80-foot-long "double-joint" sections of pipe are strung along [illegible] near Rio David. BELOW from left (front) D. Anderson, drill [illegible] Chiriqui Grande office manager, H. D. Baum and G. Teigen, gen. mechanic foremen, G. Martin, warehouse manager, N. Choy, associate engineer, (middle), F. Calon, project manager, [illegible] senior office engineer, B. Markwell and [illegible] Rasberry, supts. [illegible] MacDonald, gen. mechanic foreman, H. Boyle, mechanical supt., J. [illegible], general mechanic foreman, L. May, asst. excavation supt., C. [illegible], excavation foreman, (back) D. Clark, general mechanic foreman, M. Alcock, asst. general equipment supt., B. Outsler, materials [illegible], C. Price, asst. tube supt., B. Steele, general mechanic foreman, M. Barron, mechanic foreman, and A. Pagoni, asst. buildings supt.



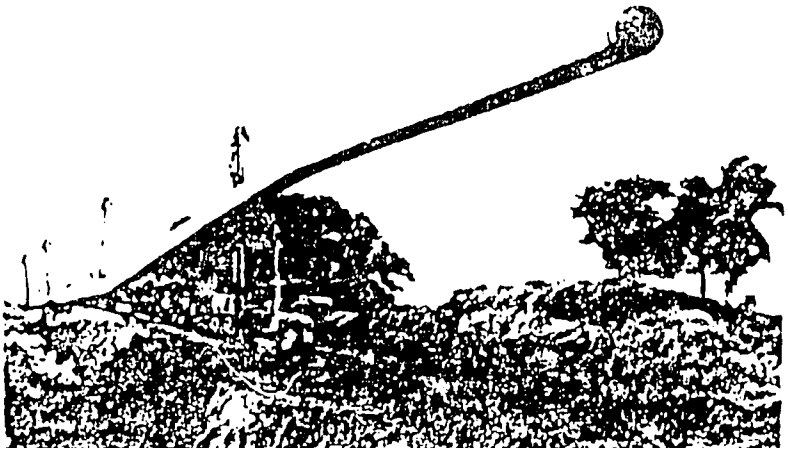
ABOVE, sideboom tractors cradle long string of pipe coated with heavyweight concrete prior to placement at river crossing. More than 37,000 tons of pipe are required for the job.

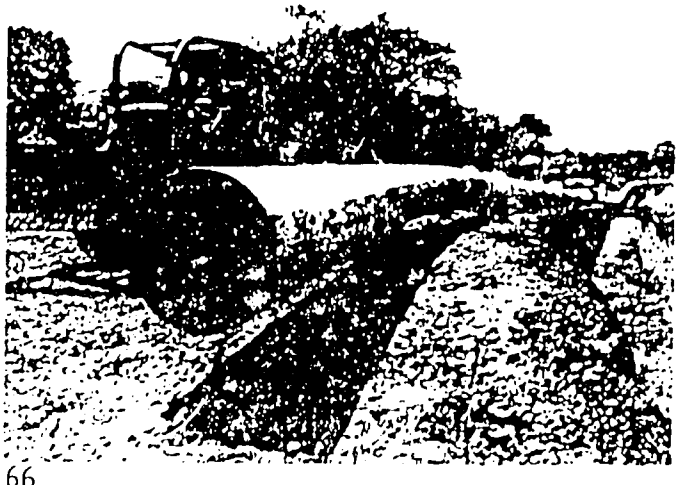
manager of onsite activities for Northville Terminal Corporation, owner's representative on the project.

An advanced communications and instrumentation system is being installed to control and monitor operations of the pipeline, pump stations and terminals, including a 12-channel point-to-point microwave communications system that will link all portions of the project. As part of this system, M-KI is installing five microwave towers, including a 180-foot-high repeater tower at Volcan Baru peak high in the mountains, one of only a few places in the Western Hemisphere where the Pacific and Atlantic oceans can be viewed from the same point.

The Trans-Panama Pipeline System is set for completion late this year. Once it begins pulsing with oil, it will assume its role as an unseen yet vital artery — the Panama petroleum "canal."

ABOVE, LEFT, from left (front) M. Cordova and Victor Kaa, clerks, J. Conrad and L. O'Lisser, topographers, M. Murgas, draftsman, T. Kelly, [illegible] D. Reilly, senior field engineers, K. Tinker, field engi[illegible] (back) J. Zelaya and J. Caballero, draftsmen, Fred Gilette, associate engineer, A. Schwager, staff engineer, Bill Keys, senior materials engineer, P. Kelly, senior office engineer, Ed Widgeon, engineering manager, T. Domaguez, cost engineer, I. Ordonez, draftsman, R. Choy, associate engineer, and Frank X. Gillespie, senior scheduling engineer. RIGHT, Larry Kennedy, operator, Devon Campbell, mechanic, Les Hause, equipment supt., Bill McCray, materials manager, Buck Oursler, equipment gen. supt., and J. Caton, equipment supt. BELOW, LEFT, welded pipe is readied for lowering in. RIGHT, welders in background join pipe sections, with wall thicknesses of up to ⅞ of an inch.





ANNEX D

STATEMENT OF WORK--
EXCERPT FROM WORK ORDER ISSUED UNDER IQC AID/SOD/PDC-C-0399

Annex D

STATEMENT OF WORK -- EXCERPT FROM WORK ORDER ISSUED UNDER IQC AID/SOD/PDC-C-0399

ARTICLE I - TITLE

Panama Coal/Methanol Complex

ARTICLE II - STATEMENT OF WORK

The Contractor will complete and deliver to TDP by May 12, 1982, an economic and technical review of a proposal from Ebasco Services, Incorporated for a coal gasification/methanol complex in Panama. The review will examine, but not be limited to, the following topics:

1. The assumption that Japan will import substantial quantities of methanol in the future as part of total imports of liquid hydrocarbons. (Compare with imports of steam coal from Western U.S., Colombia, China.)

2. The projection that methanol produced in Panama from U.S. coal will be price-competitive, after amortization of debt, with methanol produced from natural gas in a Pacific Rim country.

3. The assumption that Japan will seek diversified sources of supply of methanol.

4. The prospects for bilateral arrangements between Japan and the U.S., whereby Japan would reduce its trade surplus with the U.S. by importing U.S. fuels, including methanol.

5. The economic, technical and political advantages or disadvantages of producing methanol in the U.S., as compared with Panama, for export to the Pacific Rim.

6. The technical and economic problems of shipping U.S. coal from midwest and southern coal fields to Panama.

7. The technical and economic problems of transportation and storage of methanol.

Reference documents for this review are "Proposal to Republic of Panama for the Panama Coal Gasification/Methanol Complex", EBASCO, January 1982, and "Supplementary Information to the United States Trade and Development Program, Panama Coal Gasification-Methanol Complex", EBASCO, April 1982.

ARTICLE III - RELATIONSHIPS AND RESPONSIBILITIES

The Contractor will submit the report to Christian Holmes, Director, TDP. The Project Officer in TDP is Joe J. Sconce.

ARTICLE IV - TERM OF PERFORMANCE

The starting date is April 28, 1982, and the estimated completion date is May 15, 1982.