BELUGA METHANOL PROJECT: COMMERCIALIZATION OF FUEL METHANOL FROM ALASKAN COAL USING PROVEN TECHNOLOGY

N. Kirschenbaum
Placer Amex, Inc.

G. Winklepleck
Davy McKee Corporation

C. A. Stokes
Stokes Consulting Group

F. Klett
Cook Inlet Region, Inc.

466/467

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Noel Kirshenbaum
Placer Amex Inc.
San Francisco, California

Frank Klett
Cook Inlet Region, Inc.
Anchorage, Alaska

Charles A. Stokes
The Stokes Consulting Group
Naples, Florida

Gordon Winklepleck
Davy McKee Corporation
Cleveland, Ohio
United States of America

Introduction

After much research and heated debate, a national alternative energy program was established by Congress in the late 1970's with the goal of drawing upon those raw energy resources that are domestically-plentiful to create new forms of fuel to replace those which have been traditionally used. Several years have passed, and though the Federal climate for developing alternative fuels has improved, the basic energy dilemma remains the same: we still lack a dependable supply of clean fuels to operate automobiles and generate power without heavy dependency on imports of crude oil and natural gas.

The Beluga project is a model of how to solve the national energy dilemma. It will use proven technology to convert a vast untapped domestic coal resource into a clean, practical, finished fuel -- methanol. Methanol can replace natural gas or oil as fuel for boilers or combustion turbines and has been in use as automotive fuel for years, albeit on a limited basis.

The Beluga Methanol Project will produce 7,500 tons of methanol per operating day or 2,550,000 tons per year with a doubling of plant size contemplated as the market develops. The project is located on deep water and a pipeline exists to take the methanol to an existing tanker loading terminal which is well situated to reach large fuel markets. Fresh water supplies are plentiful. The coal reserve is large and surface-mineable.

The gasification technology is proven, and is, in fact, in use today in plants several decades old. The methanol synthesis technology is in use all over the world.

What will it take to bring this project to fruition? What are its markets? Most important, where does Beluga fit within the long-range national energy plan covering the next 20 to 30 years?

Resource Availability and Plant Site

The Beluga coalfield, which has confirmed reserves of over one billion tons of very low sulfur subbituminous coal and more as yet unexplored, is located about 60 miles west of Anchorage. Placer Amex holds coal leases on state and private lands containing in excess of 500 million tons of surface mineable coal. The private lands are owned by Cook Inlet Region, Inc. (CIRI), one of the project sponsors. The existing reserve base allows for future methanol plant expansion as well as other coal-based projects. Production of 7500 tons/day of methanol, as contemplated for the initial plant, will require a total of about 8.5 million tons of coal annually. It is proposed that this quantity will be obtained from two mines, one in the Capps area, the other in the Chuitna area of the Beluga coalfield.

As shown in Figures 1 and 2, a noteworthy feature of the coal location and the nearby process plant site is its proximity to tidewater on Cook Inlet. The mine sites are from 15 to 20 miles from the plant site near the Inlet. The slope and terrain of the land between the mine and plant site can easily accommodate construction of the railroad which will transport the coal to the plant.

The project will be self-sufficient with regard to electric power. During construction, gas turbine units will be used, and these will be available for standby use during operation. CIRI, a co-sponsor, holds some 20 billion cubic feet of shut-in natural gas reserves about 10 miles east of the project site.

There is an abundance of fresh water in the region. Sources of groundwater and surface water are available in the area in sufficient quantity to meet process needs.

Placer Amex has conducted exploration and drilling programs of the Beluga area and its resources over a period of sixteen years. These studies were generally intended to confirm resource and reserve estimates and to analyze the mining, transportation, and marketing requirements for the utilization of the coal. In excess of $8 million has been spent to date on the Placer Amex Beluga coal properties.

Field work to obtain environmental data of the area was initiated by Placer Amex in 1974. A field program for long lead time items, such as surface hydrology and fishery studies, is continuing in order to maintain continuity of data and to meet criteria requested by State of Alaska agencies. The Beluga Methanol Project has been favored with endorsement from State and local governmental agencies.

The plant site is located principally on lands owned by CIRI, a project co-sponsor, and the balance is on Alaska State lands. A map of the project areas shows the close proximity of the plant site to Cook Inlet. Plant components, many of which will be in modular form, will be barged to a location near the plant site area, so that a minimum amount of land haulage is required. It will also be noted that the plant site is immediately adjacent to an existing pipeline, one which will be used for transporting the product to the shiploading facility.

Process Selection and Description

The production of methanol from coal requires multiple processing steps. Each process stage has been carefully examined for maximum energy yield in order to achieve the highest overall plant thermal efficiency.

The Beluga project design is based on commercially available and demonstrated technology. All major units have been selected to provide an integrated process plant with maximum reliability. The design incorporates multiple trains, the sparing of critical items and the incorporation of equipment of commercially available size. Particular attention has been given to the optimal integration of all utilities and heat recovery systems and to controlling environmental impact to regulated levels. As a result, an efficient, proven configuration for the 7500 STPD fuel grade methanol plant complex has been developed.

The multiple processing steps and trains for this world scale plant are shown in Figure 3.

Gasification

The gasification section provides the mixture of H_2, CO and CO_2 for methanol synthesis. Three commercially proven large scale coal gasification processes capable of producing this synthesis gas from Beluga coal were considered before a process was selected:

Lurgi	- dry ash/fixed bed
Winkler	- fluid bed
Koppers - Totzek	- entrained

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For a given coal in a specific situation, one of these processes is optimum. For Beluga coal, it was concluded that the Winkler fluid bed system is the most appropriate.

Some characteristics of the Winkler favoring its selection for the Beluga project are:

- High throughput of highly reactive coal.
- Tolerance for high and variable ash content.
- Acceptance of -3/8" coal with fines.
- Moderate coal predrying to 8-10% moisture.
- Optimum carbon utilization.
- Negligable tar, phenols, ammonia, etc.
- Higher H_2/CO ratio requires less shifting.
- Methane production large enough to justify reforming.
- Dry char suitable for offsite boiler.
- High turn down.
- Gasifier can be "Banked" if complete shutdown needed temporarily.

A diagram of the Winkler gasifier with coal lock hoppers and screw feeders and waste heat boiler is shown in Figure 4. The gasifier operates at about four atmospheres pressure. This is about three atmospheres above existing operating Winkler units. The small increase in pressure is well within proven applications of the coal feed system. The increased pressure provides important economies in gasification and compression. Further, one gasifier out of the eight is designed for ten atmospheres. Such operation will produce data for designing expansion or for revamping existing plant to higher capacity.

The refractory-lined, conical bottom gasifier vessel is blown with steam, oxygen and steamoxygen mixture. This arrangement not only develops a fluidized bed of coal for gasification but creates a higher temperature in the freeboard space above the bed. This high temperature, while below the ash softening point, cracks the condensible hydrocarbons and eliminates their residuals.

Heat recovery is achieved in an annular radiant heat exchanger near the top of the gasifier vessel. This heat is added to that from the waste heat boiler and generates superheated steam for certain plant prime movers. Other sources of such steam are the boilers fired with coal and char and the reformer heat recovery boilers.

The high-ash char carry-over from the gasifier is collected by cyclone separators. This material, containing about 30 percent carbon is added to the coal used for steam and power generation in the power plant. The bottom ash from the gasifier contains about two percent of the total char and is not utilized.

A venturi scrubber following the cyclone provides the final stage of particulate removal. The aggregate carbon loss from rejected high ash char is about 3 percent of the carbon fed to the plant.

Synthesis Gas Upgrading

Synthesis gas upgrading includes four major gas processing steps:

- Compression from 40 psia to 1390 psia (methanol loop pressure).
- Adjustment of H_2 to CO ratio.
- Removal of all sulfur compounds and other catalyst poisons.
- Reduction of CO_2 content.

The sequence of processing is shown in Figure 5.

The first step in this section is raw gas compression which increases the pressure of the gas from 40 psia to 770 psia. Centrifugal, multi-body turbine driven compressors are used.

After compression the gas is then saturated, preheated, and sent through a CO shift reactor, where the ratio of hydrogen to carbon monoxide is adjusted with sulfur-resistant catalyst to the required level for methanol synthesis. The reactor is a packed bed of catalyst.

From COS hydrolysis, the raw gas goes to a Selexol acid gas removal unit where the sulfur components in the gas are removed and the CO_2 level in the gas is adjusted to the required percentage for methanol synthesis. This process is selective in that H_2S is removed in the first absorber and CO_2 is removed with a second absorber. Since the solvent is recirculated, it must be continually regenerated by flashing. The absorbers are packed columns in which the gas streams are contacted with the liquid solvent. The purge gas stream leaving the H_2S flash system is sent to the sulfur recovery unit.

The gas leaving the CO_2 vent is 99%+ CO_2 and is simply vented. The synthesis gas leaving the Selexol unit contains only trace levels of H_2S and COS and has the proper ratios of CO, CO_2 and H_2 for methanol synthesis. Guard beds are provided for removal of any trace sulfur compounds and other catalyst poisons.

The final stage in this preparation area is make-up gas compression. The synthesis gas is compressed to the level required for methanol synthesis, which is 1390 psia. Turbine driven, centrifugal type compressors are used.

Methanol Synthesis and Purge Gas Reforming

The ICI low pressure methanol process is used in this section of the plant. In order to produce 7500 STPD of product methanol, three (3) synthesis and distillation trains are required. A schematic of one train is shown in Figure 6.

The Davy McKee/ICI methanol converter is a pressure vessel of single-wall design constructed of low-alloy steel holding a single continuous bed of catalyst. Temperature control of the exothermic reaction is achieved by injecting feed gas at appropriate levels directly into the bed, using specially developed distributors.

The converter exit gas is split for optimum heat recovery; one part heats the feed gas to the top of the converter, and the second heats the CO shift saturator water and reboils the distillation column. The crude methanol is separated and let down from loop pressure to 60 psia.

The nonreactive components (mainly CH_4 and N_2) in the make-up gas are purged from the synthesis loop between the separator and the point of make-up gas addition. This purge gas and the flash gas from the letdown vessels are used as feed to a Davy McKee modular steam reformer. Seventy-five (75%) of this gas is used as process feedstock, and 25% is utilized as fuel for the reformer furnace. The reformed gas is recompressed and blended with the main synthesis gas stream.

The endothermic reforming reaction receives well distributed heat input in the radiant box through roof burners. This automatically supplies adequate heat at the top of the reformer tubes where the endothermic reaction is proceeding most rapidly.

The mixed steam and purge gas enters the catalyst-filled reformer tubes through manifolds and flexible inlet pigtails. The reformed gas is collected through similar pigtails and Incoloy manifolds.

Heat is recovered from the reformed flue gas in the convection section which contains the waste-heat steam-generating surface.

Methanol Distillation

A one-column distillation system illustrated in Figure 7 is provided to produce the required product purity. Crude methanol from the letdown vessels flows to the preheater and then to the column. The reboiler heat is provided by part of the converter exit gas. The purpose of the distillation column is to remove water and the light ends from the crude methanol. The column overhead is completely condensed and returned to the column as reflux as well as to the reformer. Product methanol is withdrawn three trays below the reflux tray and is cooled prior to passing [redacted] [redacted]

to the methanol product storage tank. The distillation column bottoms, which is essentially water, is cooled and pumped to the wastewater treatment area.

Overall Balances

The Beluga project is designed for maximum utilization of chemical heat in the mined coal to produce fuel grade methanol with minimum environmental effects. The project is self-sufficient with respect to utilities. The only by-product considered saleable is a large quantity of high purity CO_2, anticipated to have a market for enhanced oil recovery in the nearby Cook Inlet production field.

The overall material and heat balance is given in Figure 8. Coal is mined at the rate of 8.55 million tons per year. It is fed to the process and boilers at a rate equivalent to 14.4 x 10^9 Btu per hour.

Fuel grade methanol production accounts for 6.2 x 10^9 Btu HHV per hour. This corresponds to 7500 STPD or 2.55 million STPY for 340 operating days per year.

TRANSPORTATION AND DISTRIBUTION

Transport from Plant to Port

The existence of a well-maintained pipeline system to transport methanol the 42 miles to the Drift River Terminal is of obvious and substantial benefit to the project. Some modification will be required of the existing pipeline and liquids storage system at the shiploading terminal, but this will be relatively minor.

Methanol will be pumped from product storage tanks at the plant to existing facilities of the Cook Inlet Pipe Line Co., about two miles away. The CIPL pipeline transports crude oil produced from offshore production platforms in Cook Inlet to that company's shiploading facility at Drift River on Lower Cook Inlet as shown in Figure 1. Because of continuously decreasing production since 1975 of petroleum from these Cook Inlet fields, there is already more than ample capacity to accommodate the 7500 tons/day production of the methanol plant in this 20-inch pipeline from Granite Point to the storage and shiploading facilities at the Drift River Terminal.

The operators of the CIPL pipeline have performed an engineering and cost study which considered batching of separate streams of crude oil and methanol in the pipeline. It was found that with the exception of an interface of small volume which can easily be directed to a special tank, methanol will not be contaminated with crude oil, associated water, or paraffinic material which could conceivably be leached from the pipeline wall. Nor will such operation result in the crude oil accumulating any substances which would have detrimental effects upon refinery operation.

The Drift River terminal will load methanol on tankers at its offshore loading platform, which routinely berths vessels up to about 70,000 DWT. This terminal is an all-weather facility and operates year-round. During winter months, ice floes are sometimes present in this part of Lower Cook Inlet, but ice coverage is much less extensive than at Anchorage, an important all-year port at the head of navigation in Upper Cook Inlet.

Marine Transport to Major Market Areas

Delivery of methanol to the important market areas of west coast states would best use efficient marine transport or pipeline systems. In the Western States, however, trunk pipelines are generally limited to routes along three major east-west corridors. The limited number and capacity of these pipelines consequently impose a constraint on this type of transport for widespread distribution of liquid fuels within the Pacific Coast states.

By contrast, the economies and flexibility inherent in marine transport are outstanding advantages of the shoreside location of the Beluga project. Ocean-going tankers sailing from the terminal at Drift River on Cook Inlet can serve the important population and industrial centers in all the Pacific Coast States. As these centers are close to the port areas, there is excellent opportunity to serve major receivers with little or no transshipment by land. Most of the ports in the Pacific Coast states are able to berth the largest vessels that can be accommodated at the Drift River Terminal.

Shipment of methanol by tankers and barges is routine practice. Intercoastal marine shipments of methanol are carried out from the U.S. Gulf Coast, and there are international movements such as Gulf Coast-to-Europe, Western Canada-to-Japan, and Libya-to-Europe-and-U.S. Marine shipment of methanol is expected to increase greatly in the next five or six years, with Saudi Arabi, Canada, Mexico, Trinidad, Indonesia, and New Zealand being major exporters.

Five principal market areas for Beluga methanol are foreseen on the West Coast. Each is a major population and industrial center and has well-developed marine facilities.

- Puget Sound: Such important port areas as Tacoma, Seattle, and Bellingham can easily berth the largest vessels accommodated at the Drift

River Terminal. Besides electric power generating units (combustion turbines) located near Puget Sound, which can utilize methanol fuel, a relatively large quantity of chemical grade methanol is brought into this area, a principal timber product manufacturing region, for the manufacture of formaldehyde.

- Columbia River: The Columbia River bar near Astoria is an impediment to deep draft ships entering this river, but vessels up to about 50,000 DWT can reach the port of Portland. A large combined cycle power plant is on the Columbia River downstream from Portland, and there is a demand in this area for chemical methanol because of the timber and plywood industry.

- San Francisco Bay Area: The largest vessels that would deliver methanol from Cook Inlet can berth in several locations in San Francisco Bay, although channels to interior ports such as Stockton and Sacramento would not be able to accommodate ships drawing over 30 feet.

- Southern California: Large ships can enter and berth at the ports of Los Angeles, Long Beach and San Diego. Several marine facilities in this area are connected by pipeline from ship's rail to fuel storage tanks of electric utilities.

- Honolulu: This is a major port which can accommodate ships that deliver fuel to the oil-burning electric generating plants on the island of Oahu.

Although much of the methanol used in the West Coast chemical industry has been brought in by railroad tank cars, at least two San Francisco Bay receiving terminals have received marine deliveries of methanol in bulk. Thus, there is established West Coast experience in receiving methanol delivered by tanker. Storage facilities at these marine terminals can be owned by customers or by bulk terminal operators.

MARKETS

Synthetic fuels when first produced are not likely to be price-competitive with petroleum fuels or natural gas. The situation is analogous to that facing a utility that might start now to build a new grassroots, coal-fired power station: The kilowatts from the new plant will not even come close to competing with the average cost of power from existing units. The problem is handled by two regulatory measures: (1) an exclusive territorial market franchise and (2) price roll-in or averaging to mitigate the effect on the consumer of the higher price of the new energy supply.

In support of synthetic fuels, however, the measures provided by Congress are different. The Energy Security Act includes guarantees of capital (loan guarantees) and absorption of the difference between a price for the synfuel sufficient to cover the producer's cost plus profit and the equivalent competitive price of the customer's alternate fuel. Additional support is available in the form of federal tax-related benefits.

Capital-intensive projects such as synfuel plants require assured full-load operation as a basic economic necessity. Although there is a temptation to market synthetic fuel where it has the highest value so the ten years of SFC price support will require the least amount of government assistance, only the electric utilities can offer a large assured (contract) market to enable the synfuels plant to operate at capacity. The higher-priced markets, such as for gasoline blends, are not now amenable to long term contracts. The most practical resolution to this dilemma is to rely upon the utility market for the first plant. Increases in production over designed capacity or construction of additional plants can provide methanol for the gasoline blends and, ultimately, the neat methanol motor vehicle fuel markets. The chemical industry market can be an exception, as some contracted sales are possible in areas like the West Coast where the market is protected by a large freight cost differential for domestic methanol from the Gulf Coast and by freight differentials and/or tariffs on foreign methanol for chemical use. (There is no tariff on fuel methanol.)

Utility markets for Beluga methanol have been identified by specific plants and units. In each case, the proposed use is backed up by adequate technical data to ensure applicability of the product as fuel for combustion turbines and gas or oil/gas fired boilers. The identified markets are several times the output of the 7500 TPD Belgua project. Only those utility plants were considered that are readily accessible to deep water and where docks, transfer lines, and tankage exists that could be used for methanol service with minimum modifications. Finally, plants were targeted that are sufficiently large consumers to justify a fuel switch. Particular emphasis is given to plants with existing environmental problems, as use of methanol can lower undesirable emissions significantly.

For a utility to enter into a long-term contract, it must be assured that the fuel price will be competitive after due allowance for any advantages methanol may offer and after allowance for differences in efficiency. Moreover, fuel contracts must be compatible with the regulatory requirements to best serve the long run interest of the ratepayers.

In the five Pacific Coast states the gasoline-blend market, using a blend of 6 percent methanol (which might use 3 percent tertiary butyl alcohol as a cosolvent), offers volume potentials of 803,000 to 3,212,000 tons/year for market penetration of 25% to 100%, respectively. These volumes are to be compared to the plant output of 2,550,000 tons/year.

The neat motor fuel market for the Pacific Coast states could develop to a potential of some 3,285,000 tons/year by 1996. At this level, it would represent about 10 percent of the passenger car population in the five-state market area.

In the blend market, methanol could be expected to require a market price of up to 20 to 25 percent less than gasoline (on a volume basis), in order to induce purchase, depending upon mileage performance and the cost of octane improvement by alternate means. Mileage performance depends on the type of engine and how it is tuned. The latter factor depends, in turn, on what happens to environmental restrictions and whether methanol in blends will be given vapor pressure latitude like ethanol. (There is no vapor pressure problem with neat methanol.) In the neat fuel market, the value of methanol will range from 65 to 75 percent of gasoline value on a volume basis. As with blends, the mileage performance depends on the type of engines; the tuning problems to meet emission constraints is much less with neat fuel than with blends.

The potential chemical market for methanol in the five-state area will be in the 0.5 to 1.0 million TPY range by the late 1980's whereas the estimated total U.S. market potential is more like 6 million tons.

No other domestic methanol projects are proposed at this time in Alaska or west of the Rocky Mountains. Thus, the Beluga project has a natural market area and all states in question have deep water ports to receive methanol directly from Cook Inlet by comparatively large tankers, i.e., in the 50-70,000 DWT class.

There is more than ample market for the Beluga project output, depending only on the factor of price. The potential market, including expansions of utility capacity to the year 2000, is enough to support several more plants the size of the initial Beluga plant.

In addition, the economics of the project are expected to be significantly enhanced by the sale of a large amount of by-product gas from the methanol plant. Over 172 million standard cubic feet of high purity carbon dioxide will be vented from the gas purification section of the plant, and over 720 million standard cubic feet of nitrogen will be a by-product of the air separation plant, of which only a small portion will be used in the methanol plant. Enhanced recovery methods using carbon dioxide have been developed for the production of otherwise unrecoverable oil. The nearby four oil fields in Upper Cook Inlet provide an attractive commercial opportunity, and several of the area's petroleum producers have responded favorably as to their interest in such use of carbon dioxide. Based on information on carbon dioxide being used for this purpose in other petroleum recovery projects, a value of $1.00 per MCF has appeared to be reasonably conservative for this high purity gas.

Because these oil fields are currently being water-flooded (secondary recovery), commencing tertiary recovery with carbon dioxide should be timely before the end of this decade. It is expected that the entire quantity of carbon dioxide will be sold to the production platforms in Cook Inlet, most of which are within fifteen miles of the plant. Although some Cook Inlet oil producers have expressed interest in nitrogen for maintaining reservoir pressure, no anticipated revenues are assumed for sale of this gas which is not so attractive as carbon dioxide for enhanced oil recovery.

Project Economics

The Beluga project is analyzed as a single entity which includes the coal mines, process plant and associated infrastructure. Transfer pricing is not used to segregate components of the project. Instead, all costs incurred by operations are included.

The saleable products are fuel grade methanol, selling basis CIF California coastal port, and CO_2 sold as-is exworks.

Capital Cost

Capital cost for the project, including coal mines, at time of start-up is estimated to be $2.3 billion in 1982 dollars. In as-spent dollars the cost is $3.3 billion. Start-up costs, working capital requirements and interest during construction raise the total capital employed to $4.0 billion. Ongoing capital expenditures are required for the mines as the stripping ratio increases over time.

Operating Cost

Operating costs for the coal mine generally increase from year to year for constant annual production. Combining the weighted average mine cost per ton of methanol with the process plant operating costs brings the total production cost to about $95 per ton of methanol (1982 dollars). The by-product credit for CO_2 sales reduces the cost to $72 per ton.

Methanol transportation via pipeline (42 miles) and tanker to California coastal ports costs $18 per ton.

The total direct costs, exclusive of capital charges, is $90 per ton CIF California coastal port.

Return on Investment

Fuel grade methanol is expected to be saleable for large scale use to electric utilities. The principal use would be in combined cycle units and in central station boilers. Because of the exceptionally low noxious emission levels from its combustion, methanol is expected to command a modest premium in Btu price over No. 2 distillate.

Project economics are based on the 1981 Tax Act. A partnership is assumed wherein the participants are able to fully utilize all tax benefits to shelter other taxable profits.

The discounted cash flow return on 100 percent equity financing is shown in Figure 9. The rate of return is given as a function of methanol selling price given in constant dollars, dollars inflated at 7 percent and with real price growth 3.5 percentage points above the inflation rate.

CONCLUSIONS

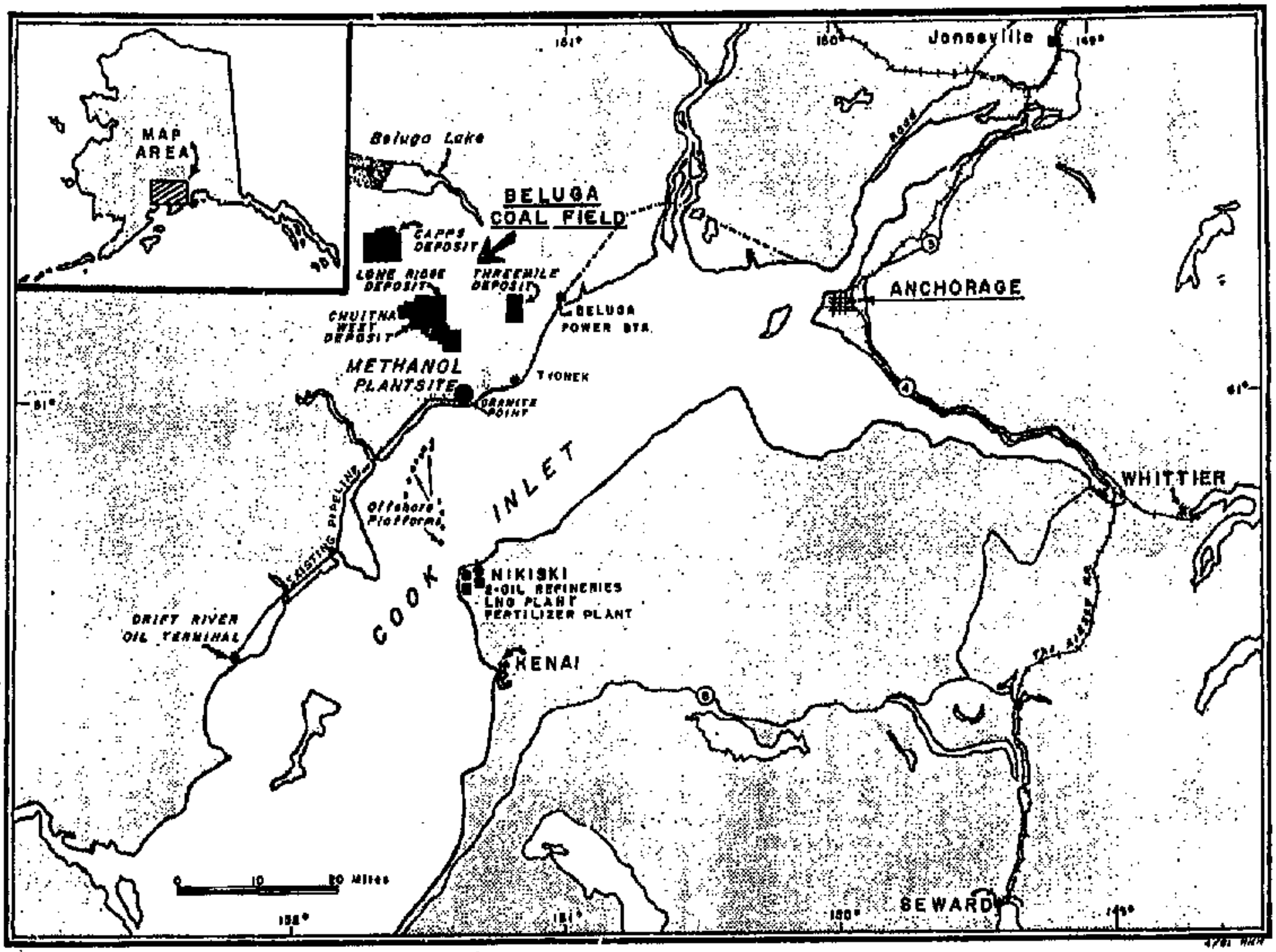
The production of methanol from Alaskan coal using proven technology is a straightforward matter involving no technological risks. Operating interruptions will be only the routine ones associated with occasional equipment failures. Even this amount of risk is kept to a very low level by parallel process lines and suitable spares and spare parts for critical equipment.

The cost of the product, when compared on an equivalent basis, e.g., making finished gasoline by direct hydrogenation of coal with no lower grade by-product fuels, is no more than other viable approaches to high octane motor vehicle fuels from coal. On the other hand, the product will cost more per million Btu than incremental gasoline made from crude oil but only because of capital charges.

Methanol from coal appears to offer the quickest and most reliable way to deliver clean fuel to the west coast market for power generation and motor vehicle fuel use. Further, methanol is unique among liquid synfuels in the degree to which it can mitigate the critical air quality problems of the west coast. Given a solution to the initial price premium required for any synfuel, the markets for Beluga methanol exist now and in a volume several times the planned Beluga output.

The problems facing synfuels investors are identical with those facing the investor-owned utilities when major new power generation facilities are required. There must be an assurance that the higher cost of the new electrical energy can somehow be rolled in and that virtually all of the new output can be used on a base load basis. Otherwise, new power stations simply cannot be built.

The choices facing the nation on liquid fuel security are no different than those faced in 1973 or that will be faced in the future until there is a proper balance among (1) the relatively low cost petroleum fuels from domestic sources, (2) the more risky but similarly priced petroleum fuels based on imports, and (3) the higher cost synthetic fuels from our large domestic reserves of coal. This balance should be made in such fashion as to insure the lowest possible cost per barrel for petroleum imports and to insure a degree of security appropriate for national economic and defense needs. A project such as Beluga is a clear example of what can be done to provide a large region of the U.S. with a clean liquid fuel made from the nation's largest fuel resource.



LOCATION MAP

FIGURE 1

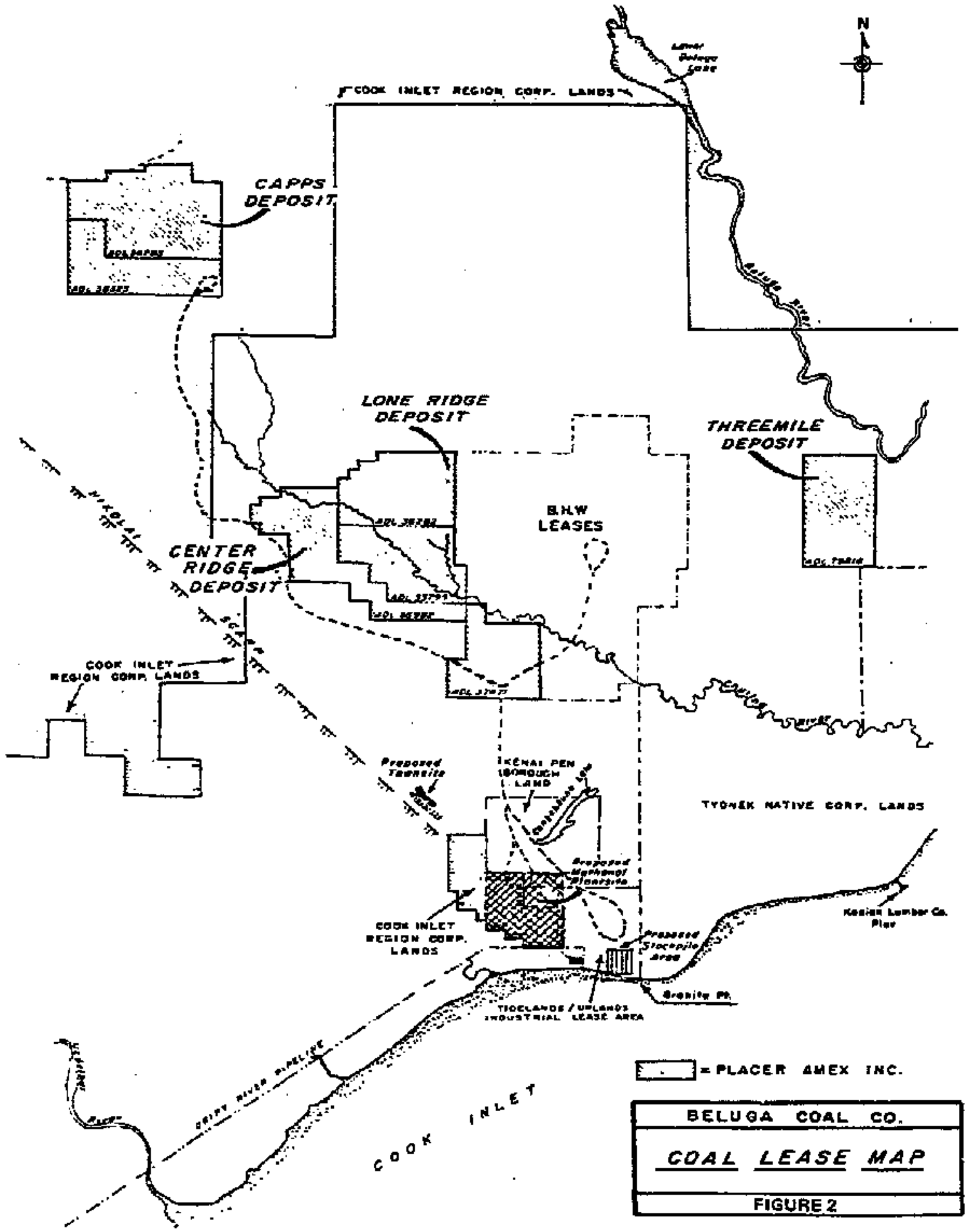
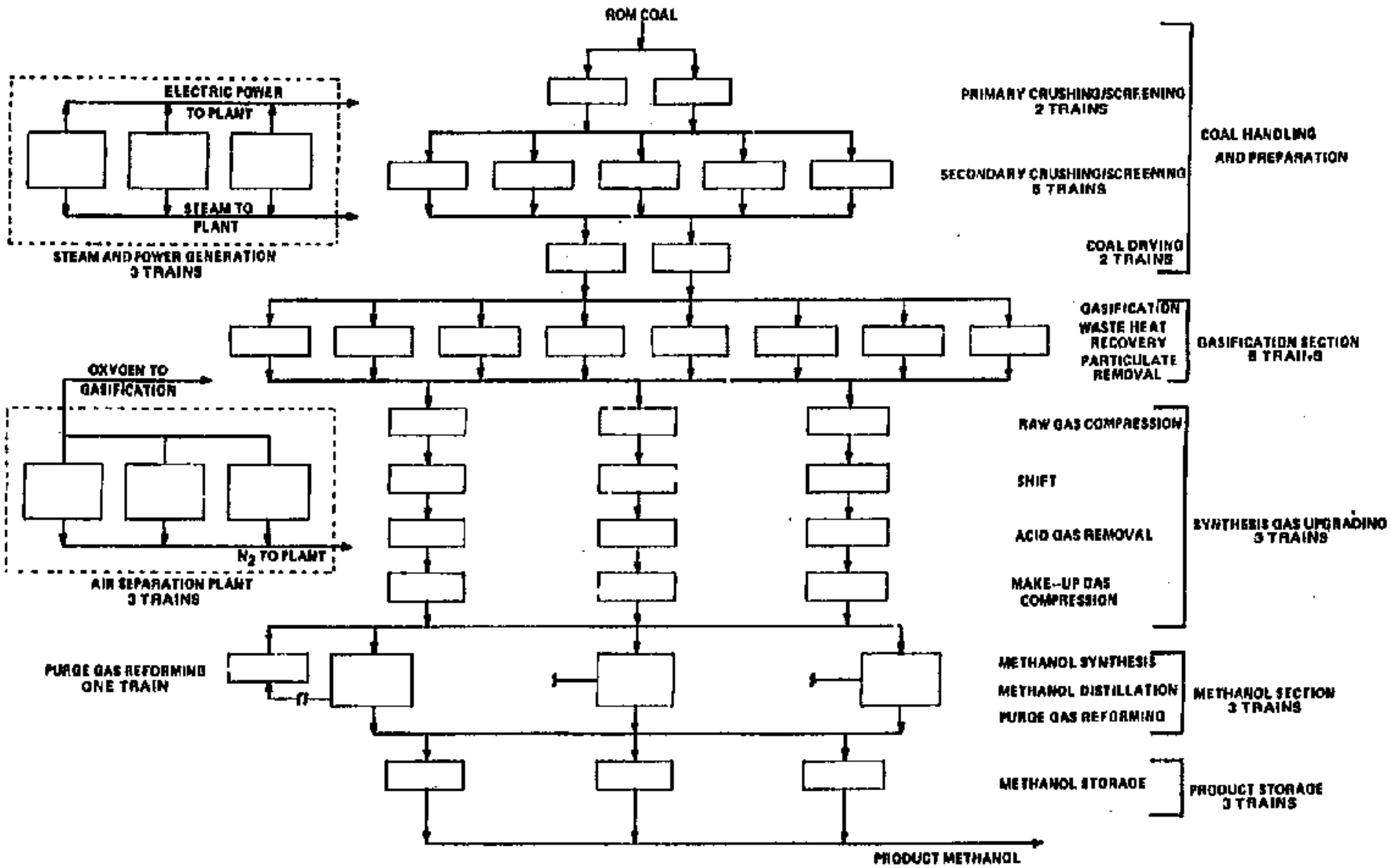

COOK INLET REGION CORP. LANDS
Lower Beluga Lake
CAPPS DEPOSIT
LONE RIDGE DEPOSIT
THREEMILE DEPOSIT
B.H.W LEASES
CENTER RIDGE DEPOSIT
COOK INLET REGION CORP. LANDS
Beluga River
Chuitna River
Proposed Townsite
KENAI PEN BOROUGH LAND
Proposed Methanol Plantsite
TYONEK NATIVE CORP. LANDS
COOK INLET REGION CORP. LANDS
Proposed Stockpile Area
Granite Pt.
TIDELANDS / UPLANDS INDUSTRIAL LEASE AREA
Kodiak Lumber Co. Pier
DRIFT RIVER PIPELINE
COOK INLET
= PLACER AMEX INC.
BELUGA COAL CO.
COAL LEASE MAP

FIGURE 2



PROCESSING TRAINS

FIGURE 3

DAVY McKEE "WINKLER" FLUID BED GASIFIER

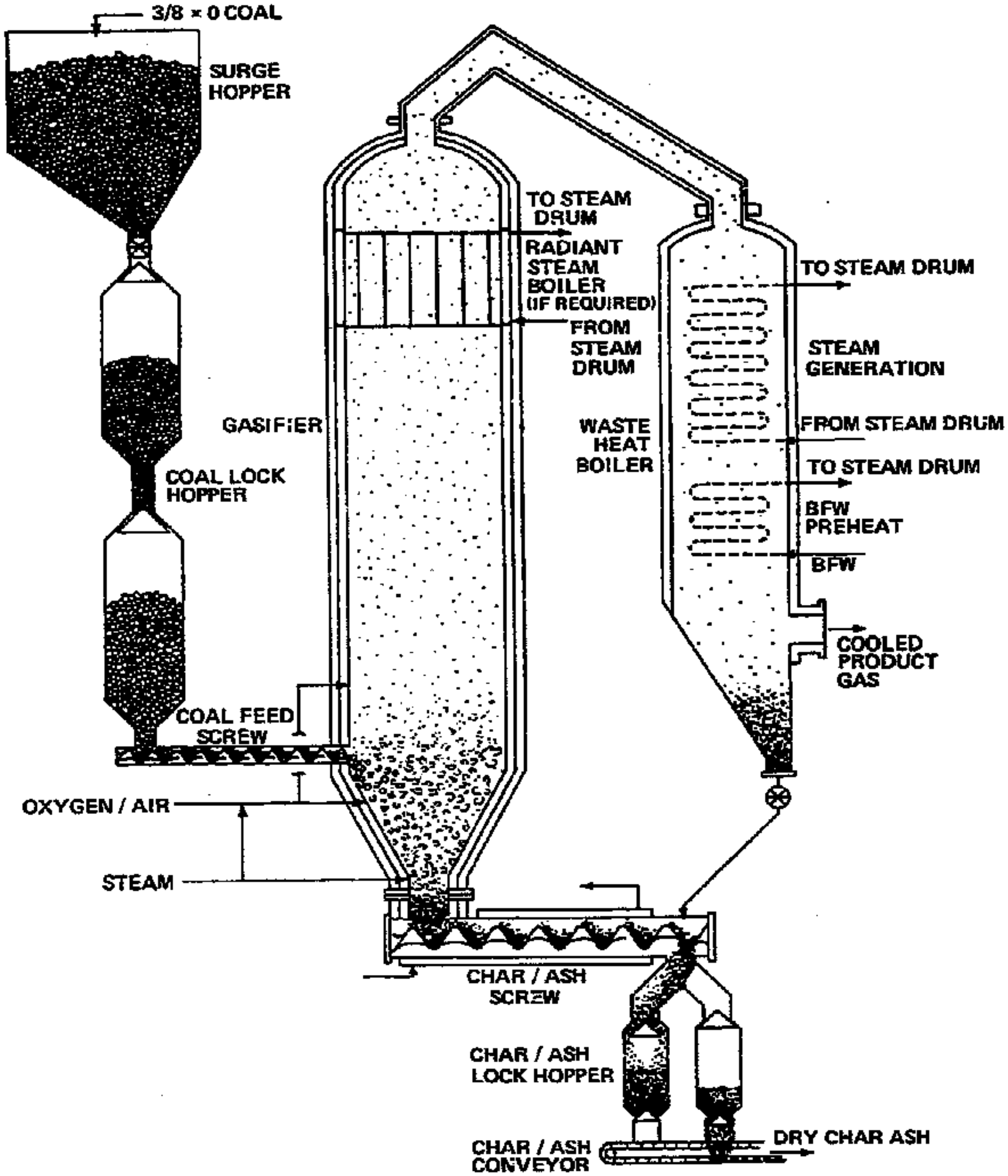


FIGURE 4

SYNGAS UPGRADING

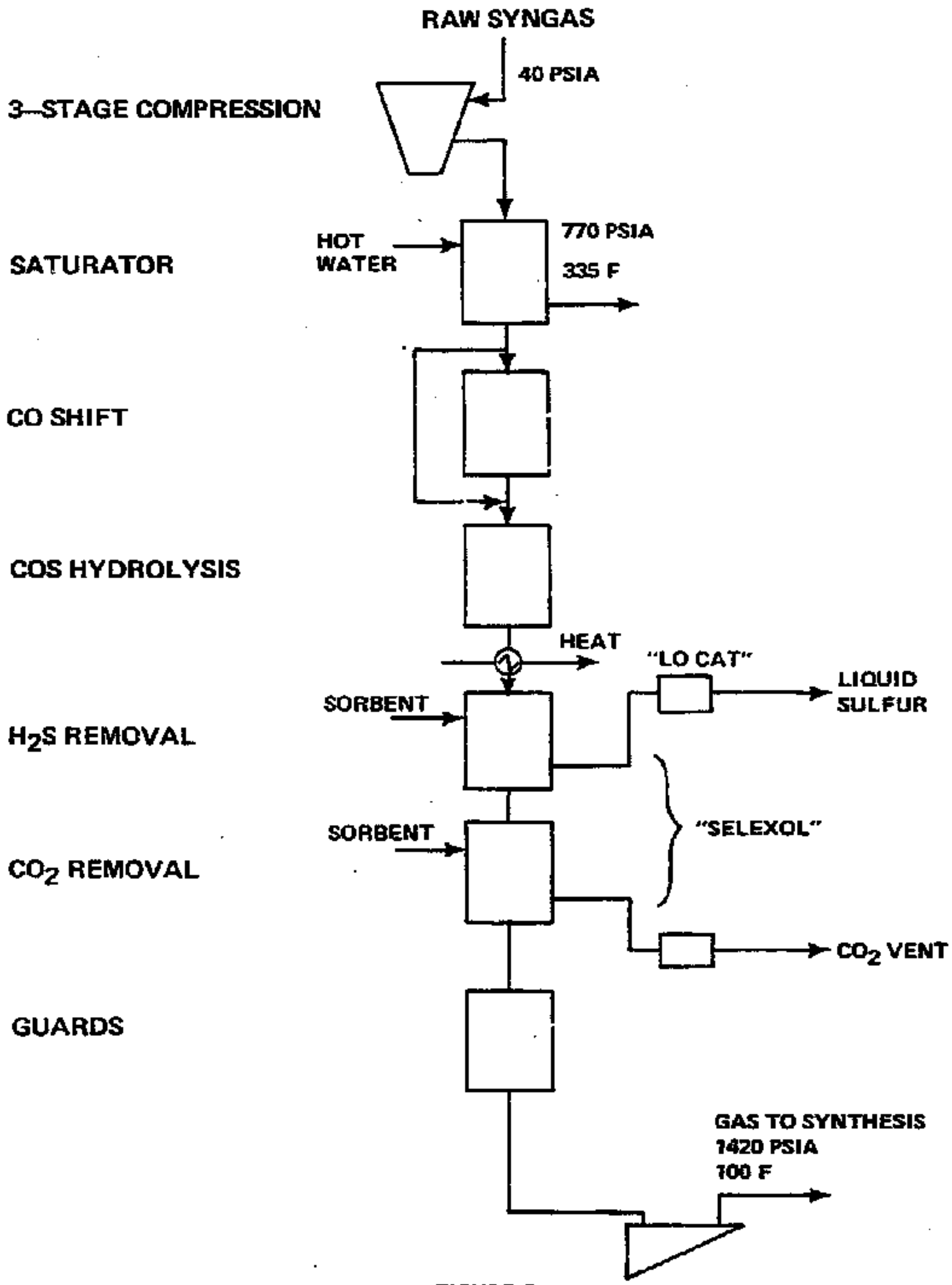


FIGURE 5

METHANOL SYNTHESIS

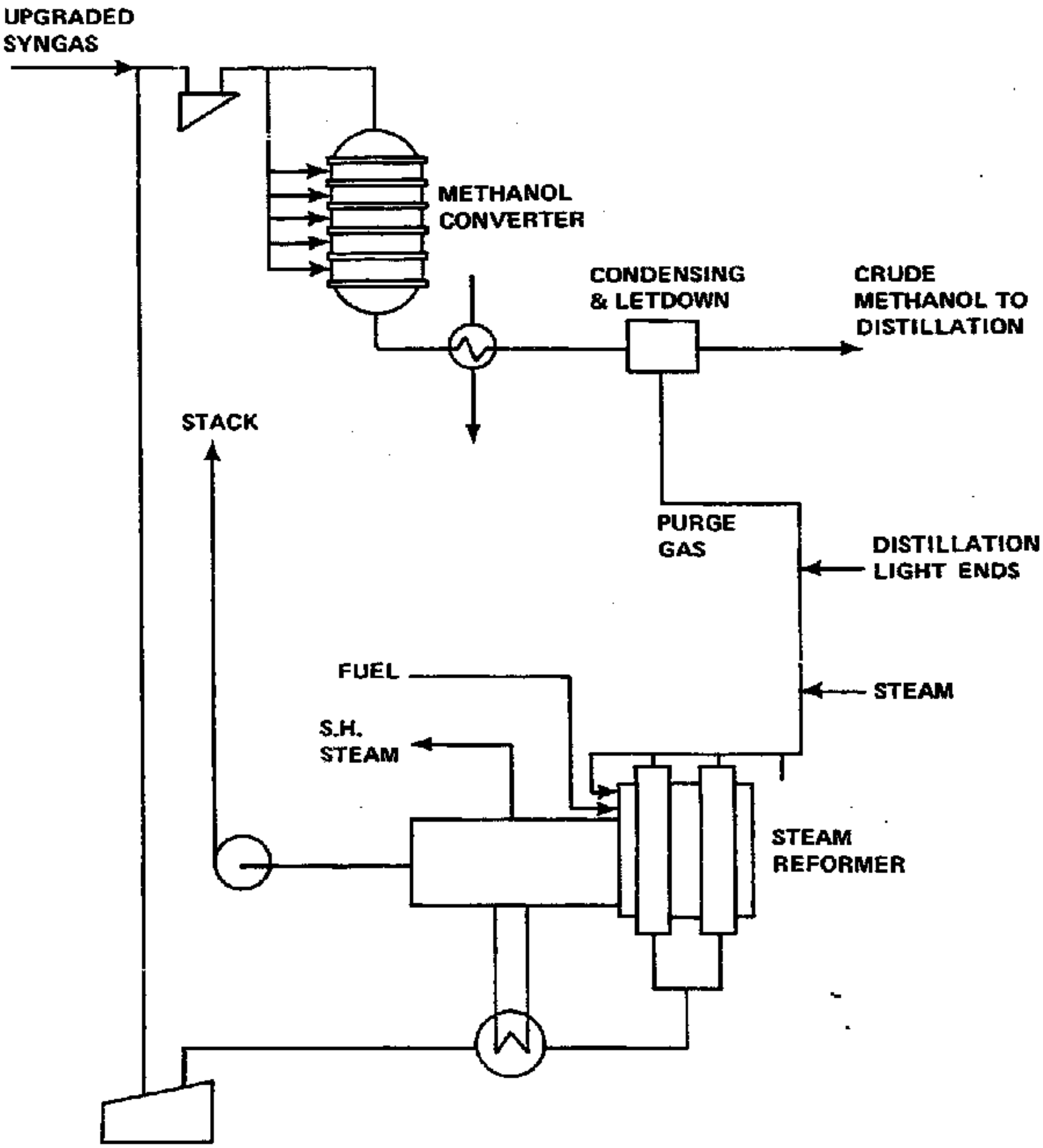


FIGURE 6

METHANOL DISTILLATION

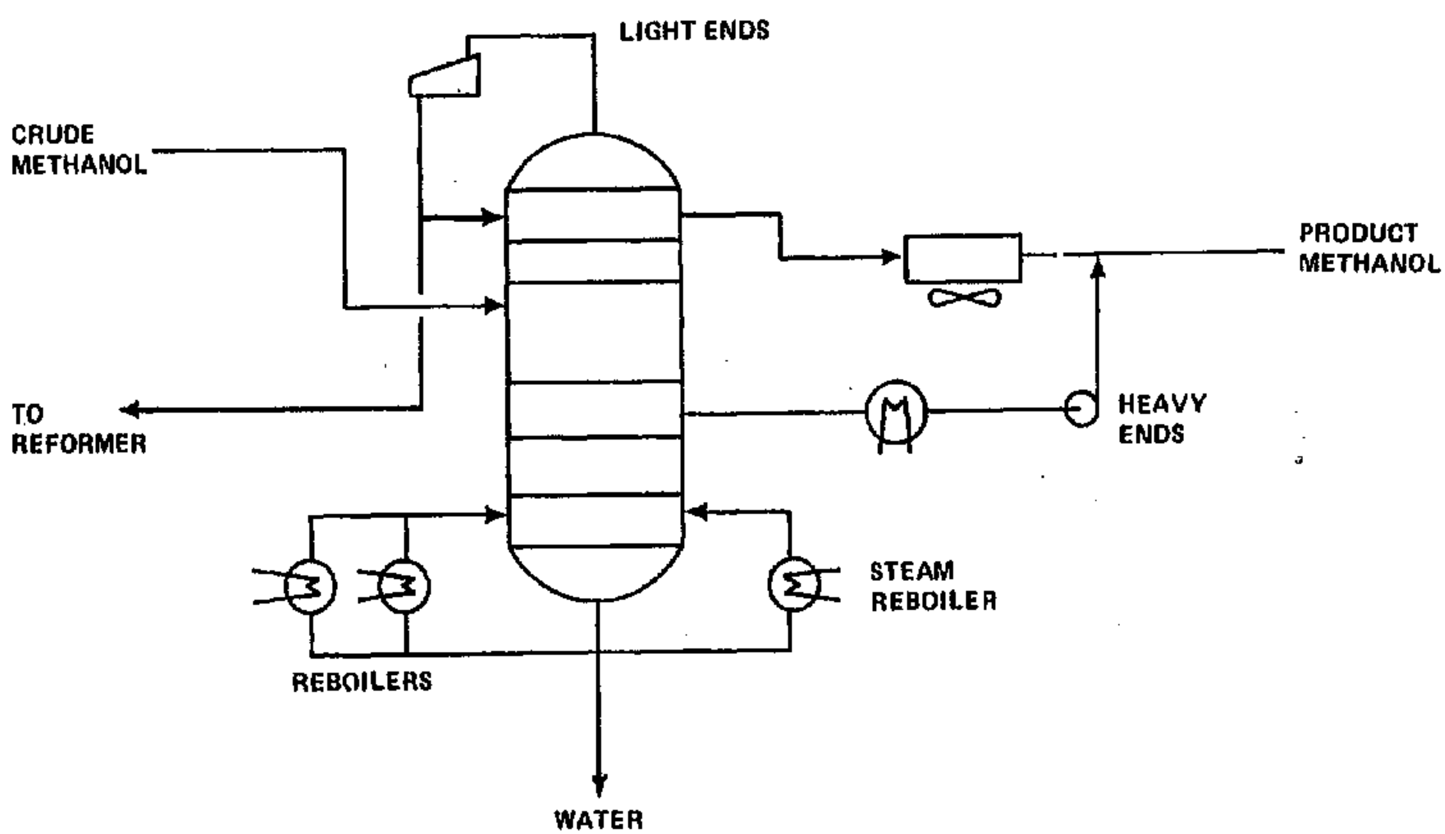


FIGURE 7

SYSTEM BALANCES

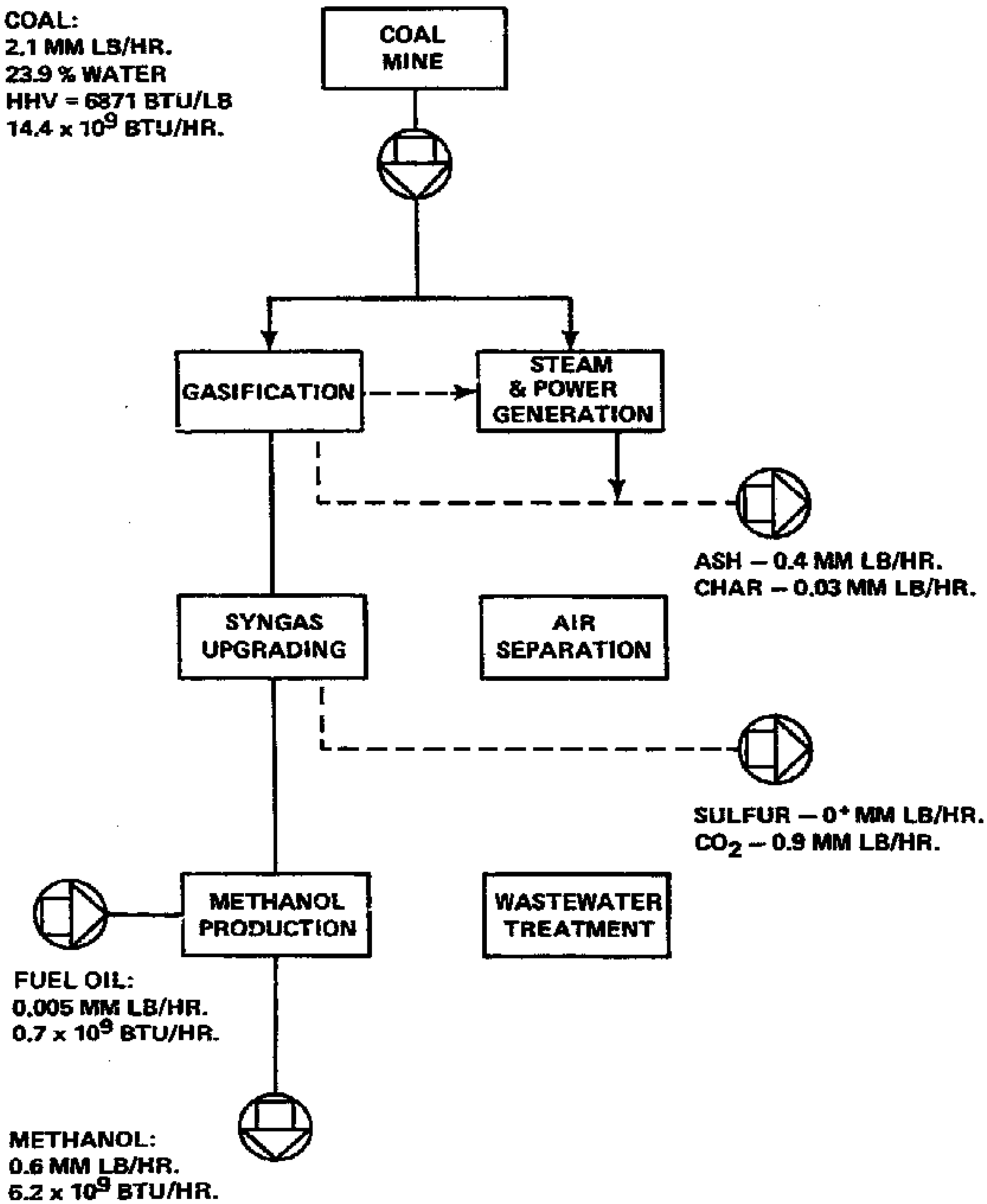


FIGURE 8

INTERNAL RATE OF RETURN
VS
METHANOL SELLING PRICE
ALL–EQUITY FINANCING

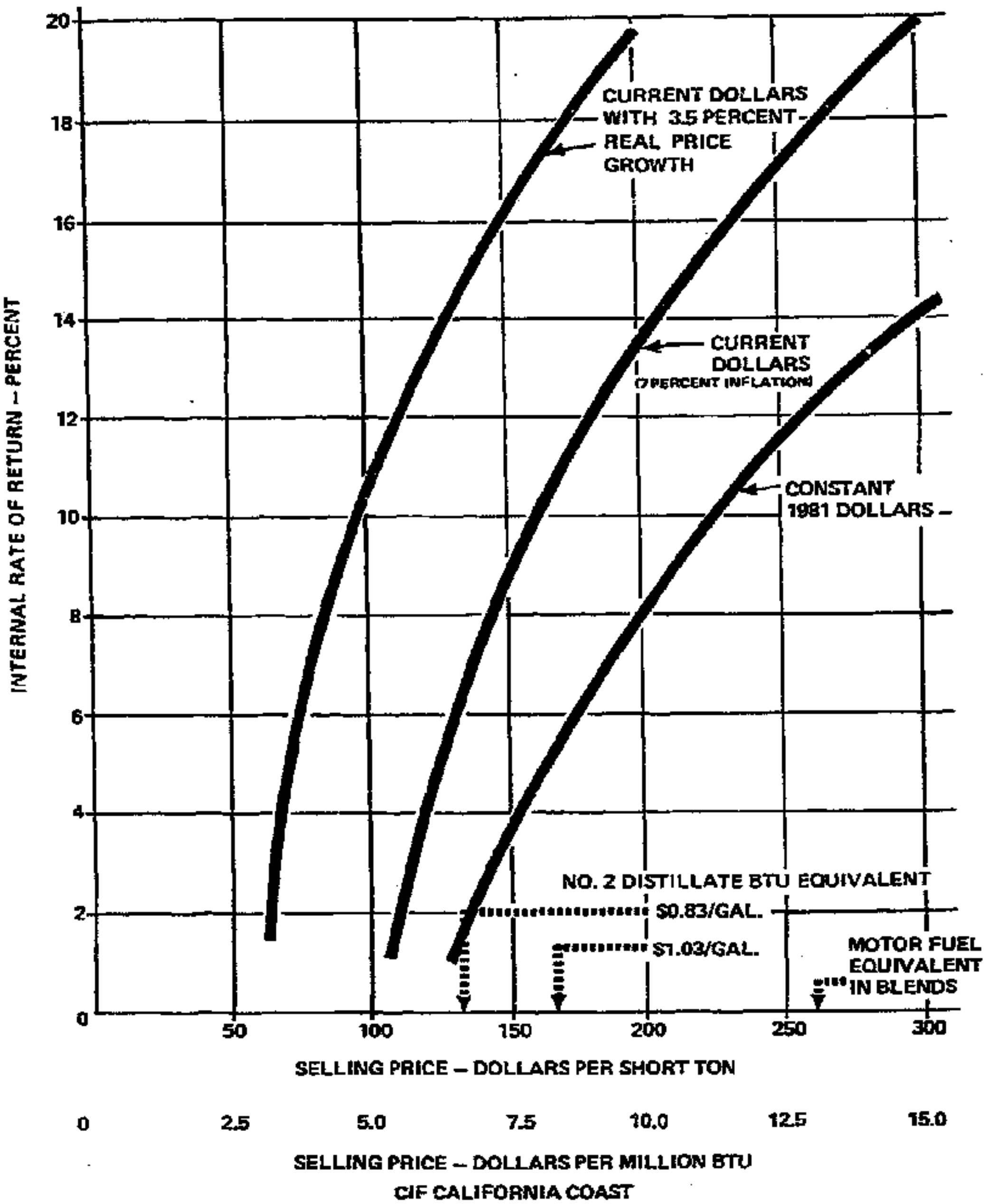


FIGURE 9