# Coal-Gasification Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska

**Volume XVII**

**Ebasco Services Incorporated**

**August 1982**

**Prepared for the Office of the Governor
State of Alaska
Division of Policy Development and Planning
and the Governor's Policy Review Committee
under Contract 2311204417**



Battelle
Pacific Northwest Laboratories

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## ACKNOWLEDGMENTS

The major portion of this report was prepared by the Bellevue, Washington, and Newport Beach, California, offices of Ebasco Services Incorporated. Their work includes the Introduction, Technical Description, Environmental and Engineering Siting Constraints, Environmental and Socioeconomic Considerations and Institutional Considerations. Capital cost estimates were prepared by S. J. Groves and Sons of Redmond, Washington, and reviewed by the Ebasco cost estimating department in New York City. Cost of energy estimates were prepared by Battelle, Pacific Northwest Laboratories of Richland, Washington.

## PREFACE

The state of Alaska, Office of the Governor, commissioned Battelle, Pacific Northwest Laboratories (Battelle-Northwest) to perform a Railbelt Electric Power Alternatives Study. The primary objective of this study was to develop and analyze long-range plans for electrical energy development for the Railbelt Region (see Volume I). These plans will be used as the basis for recommendations to the Governor and Legislature for Railbelt electric power development, including whether Alaska should concentrate its efforts on development of the hydroelectric potential of the Susitna River or pursue other electric power alternatives.

Preliminary assessment of coal-gasifier combined-cycle power plants indicated that they may offer the potential for efficiently utilizing the abundant Alaskan coal resources to generate a gas turbine-compatible fuel, thereby capitalizing on the high efficiency of combined-cycle technology. The ability of this process to accept pulverized, run-of-mine Beluga coal suggests that it will have a very low fuel cost. A modest plant size is appropriate for anticipated future capacity requirements of the Railbelt Region. Thus, a nominal 220-MW-capacity plant was selected for study. This report, Volume XVII of a series of seventeen reports, documents the findings of this study.

Other power-generating alternatives selected for in-depth study included natural gas-fired combined-cycle power plants, the Chakachamna hydroelectric project, the Browne hydroelectric project, large wind energy conversion systems and coal-fired steam-electric power plants. These alternatives are examined in the following reports:

Ebasco Services, Inc. 1982. Natural Gas-Fired Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Chakachamna Hydroelectric Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Browne Hydroelectric Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Wind Energy Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Coal-Fired Steam-Electric Power Plant Alternatives for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

## SUMMARY

Substantial deposits of accessible and surface-mineable coal in the Beluga area of the Railbelt Region of Alaska provide an opportunity for the development of coal-based, electric-generating facilities to meet future electric demand in the Railbelt Region. The purpose of this study is to examine the technical, economic and environmental characteristics of a coal-gasifier combined-cycle power plant located in the Beluga area and supplied by coal taken from proposed surface mines in the Beluga Coal Field.

The plant design selected for study is a nominal 220-MW coal-gasifier combined-cycle plant utilizing two combustion turbines of 74.5 MW capacity each and a heat recovery steam generator supplying a steam turbine generator of 100 MW rated capacity. Gross plant rating is thus 249 MW; net rating, less internal loads of 29 MW, is 220 MW at standard conditions. The annual average heat rate is estimated to be approximately 9287 Btu/kWh. A forced outage rate of 8 percent and a scheduled outage rate of 7 percent would provide an equivalent annual availability of 86 percent. Sulfur recovery is by multiple Claus units followed by Stretford tail gas cleanup. Heat rejection is by mechanical draft wet-dry cooling tower. The plant would be located in the Beluga area, northwest of Cook Inlet. Power would be transmitted by 345-kV line approximately 75 miles to the proposed Anchorage-Fairbanks intertie.

Overnight capital cost for the proposed plant was estimated to be 3284 $/kW. Working capital (54-day emergency coal supply plus 30-day O&M costs) was estimated at 26 $/kW. Fixed and variable operation and maintenance costs were estimated to be 16.87 $/kW/yr and 0.67 mills/kWh, respectively. Levelized busbar energy costs were estimated for various capacity factors and years of first commercial operation using forecasted Cook Inlet natural gas prices prepared elsewhere in the Railbelt Electric Power Alternatives Study. For a 1991 startup date and an 85 percent capacity factor, a levelized busbar power cost of 63 mills/kWh was estimated. All costs are in January 1982 dollars.

Environmental effects of the proposed plant are expected to be relatively minor when compared to alternate fuel-combustion technologies. Overall $NO_x$ emission levels would be controlled to the applicable $NO_x$ standard of 0.014 volume percent of total flue gas. Sulfur dioxide released to the environment is minimized through incorporating sulfur removal, recovery and tail gas cleanup units in the process. Total sulfur emissions are estimated to be 0.0075 lb/MMBtu (as sulfur). Particulate release could be controlled through conventional technology to an estimated 0.009 lb/MMBtu. Other emissions are estimated to be 0.003 lb/MMBtu hydrocarbons and 0.010 lb/MMBtu carbon monoxide.

Gross water requirements total 1525 gpm at full power, of which 1303 gpm would be consumed and 222 gpm discharged. Estimated land requirements for the plant are 80 acres plus land required for transmission line, gas pipeline and access road right-of-ways.

The estimated peak construction work force of 1000 personnel could produce severe boom-bust effects in the Beluga area.

A potential constraint to development is the need for a developed Pacific Rim market for Beluga coal. The outlook for development of such a market appears to be excellent. Beluga coal could be available as early as 1986 but certainly by 1988 (Swift 1981).

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# 1.0 INTRODUCTION

The integration of a coal gasifier with combined-cycle technology would allow the use of coal resources abundant in the Railbelt Region to fuel an efficient, technically proven, combined-cycle-type generating plant. In a plant of this type, coal is gasified in an air- or oxygen-blown gasifier, producing a low- or medium-heating value gas (150 or 300 Btu/ft$^3$), respectively. This fuel is used in combustion turbines to generate electricity. Steam is produced from the combustion turbine exhaust. This steam, along with steam produced in the gas cooler section of the gasifier, is used in a steam turbine to produce additional electricity.

Suitable gasifiers for this plant are not now commercially available. However, several first-generation gasifier units in a basic 1000 ton/day prototype module size are being built for demonstration in Europe in the 1983-1984 time frame. Other designs are being built for commercial operation during 1984 in the Republic of South Africa. It is expected that second-generation gasifier technology required to support a plant such as that described in this report will be available by 1985 when design validation operational data are available from units now under construction.

The combined-cycle portion of the plant would use modified combustion turbine designs such as those being developed in West Germany. Combined cycle technology has, in general, been widely used for the last 15 years in the electric utility industry.

The principal advantage of this alternative is that it will allow relatively abundant Alaskan coal resources to be efficiently utilized to generate a fuel that is suitable for combustion turbines and thus capitalize on the high efficiency and other advantages of combined-cycle technology. An overall efficiency of 37 percent is projected at the 220-MW size. Since the coal must be in a finely pulverized state for gasifier use, the entire output of a mine (including fines) is acceptable as feed. Because of the high cycle efficiency, and the ability to use the lowest cost coal, this alternative will have a very low fuel cost.

The gas produced contains no tars, phenols, condensible hydrocarbons or organic sulfur compounds. The only byproducts are elemental sulfur, a small amount of ammonia, and the gasifier ash. Other advantages of this alternative include low air emissions and the capability of a plant to be expanded in a modular fashion.

Because the gasifier operates at very high temperatures, a high quality synthesis gas is formed that consists essentially of hydrogen and carbon monoxide. Therefore, this alternative has the potential for converting part of the synthesis gas to methanol during non-electrical peak periods if the power plant is operated in a peaking mode. Sale of methanol could increase project revenues and result in a lower cost of electricity.

The primary disadvantages of this alternative are that optimum gasifier systems are not yet commercially available, and present turbine designs must be modified to accommodate a higher mass flow. A coal gasifier combined-cycle plant will have higher capital costs, require more operators and greater maintenance than a coal-fired power plant of comparable size. A greater land area will be required for this alternative than a comparable conventional coal plant; and as the gasifier will contain tall towers and stacks as well as large coal piles, the aesthetic intrusion of the plant could be locally significant. Another potential problem may exist with the disposal of large quantities of process and cooling water.

The power plant described in this report will utilize two 45-ton/hour entrained-flow, oxygen-blown gasifiers and two large-frame combustion turbine generators, each producing approximately 74.5 MW. A nominal 100-MW steam turbine generator, operating off a waste heat recovery boiler, will be used, resulting in a total gross output of approximately 250 MW. The auxiliary plant load will be approximately 30 MW, and therefore the net output will be 220 MW. Sulfur recovery will be by multiple Claus units with Stretford tail gas cleanup. A wet-dry cooling tower will be used for waste heat rejection. The plant will be located in the Beluga area of Cook Inlet.

Coal quality assumptions used for this study are typical of the Beluga fields and are as follows:

| | |
|---|---|
| Heating Value | 8,000 Btu/lb |
| Ash Content | 8% avg - 11% max |
| Moisture | 28% |
| Sulfur | 0.20% |
| Nitrogen | 0.60% |
| Ash Softening Temperature | 2350°F |
| Ash $Na_2$ | 0.10% |
| Hardgrove Grindability Index | 30 |

# 2.0 TECHNICAL DISCUSSION

## 2.1 PROCESS AND AUXILIARY SYSTEMS DESCRIPTION

The fuel for the combined-cycle plant will be medium-Btu gas (MBG) generated by the gasification of Beluga coal using an entrained flow gasifier of the Shell design. The gas treatment section of the gasifier plant will be of the Koppers design. The Shell design was selected on the basis of the high moisture content of Beluga coal and the requirement for the power plant to be capable of operating in a load-following mode.

The input coal is pulverized, then fed to the gasifier reactor by means of pressurized lockhoppers. The coal reacts with oxygen in the reactor at temperatures above the ash fusion point, in substochiometric combustion, to produce hydrogen, carbon monoxide and a small amount of carbon dioxide. The product gas has a heating value of about 300 Btu/$ft^3$. Ash in the coal is fused into small pellets that are removed through lockhoppers. The product gas is cooled, giving its sensible heat to produce steam for the steam-bottoming cycle. After cooling, unreacted coal and ash particles are removed from the product gas and are recycled to the coal input section. The product gas is then passed to a gas cleanup section where sulfur is removed.

The combined-cycle plant design is based on using two currently available General Electric gas turbine generators, rated at approximately 74.5 MW each, in combination with a General Electric steam turbine generator rated at approximately 100 MW. The heat recovery steam generators (HRSGs), one to each gas turbine, and the gas cooler heat exchanger will collectively generate the steam required for the steam turbine. The plant will also include an oxygen plant, coal handling facilities, and sulfur recovery units (Figure 2.1). Water injection will be used for $NO_x$ control in the gas turbines.

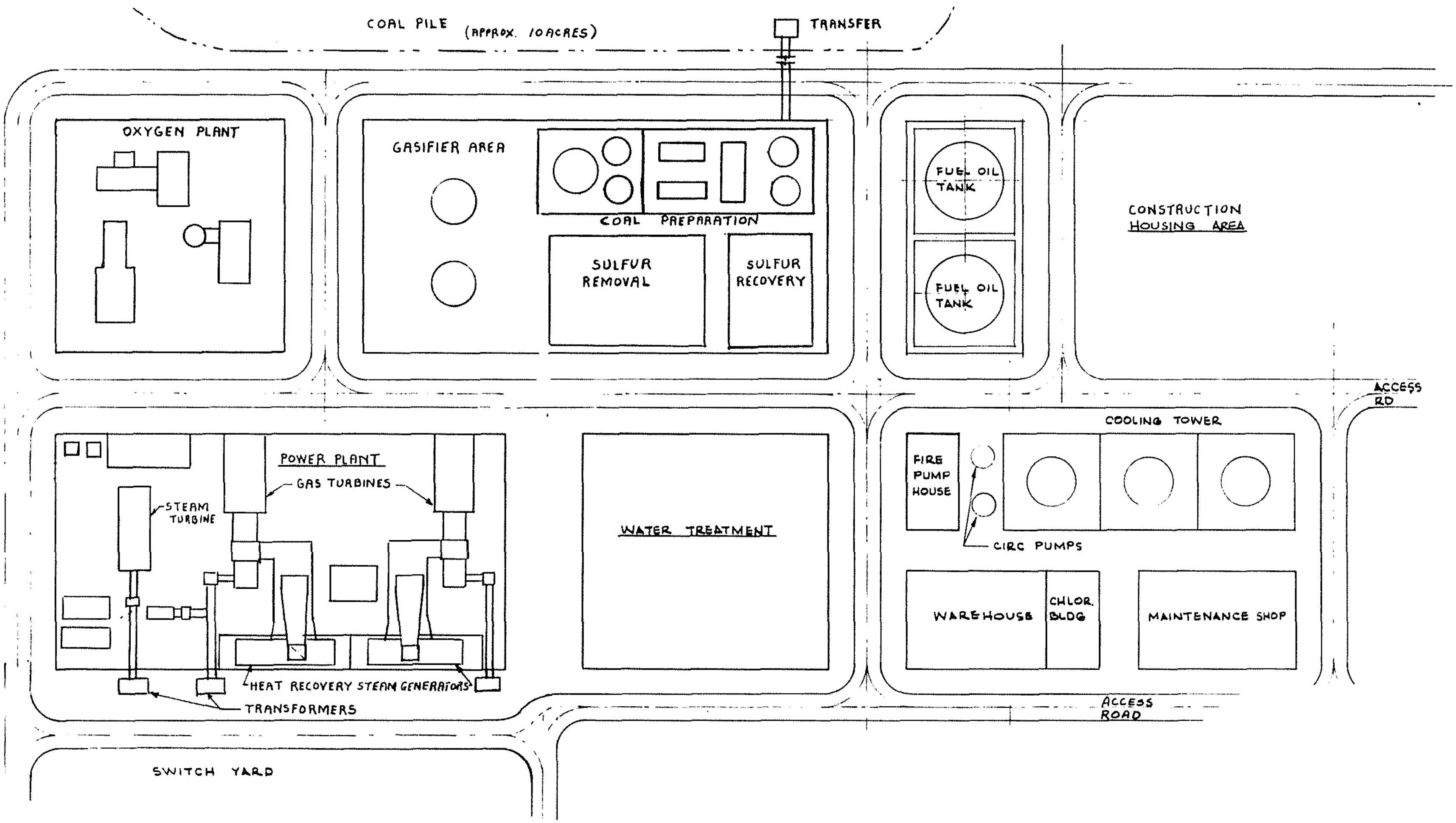



FIGURE 2.1. Plot Plan

At International Standards Organization (ISO) referenced conditions (59°F and sea level), plant performance in the combined-cycle mode would be as follows:

| | |
|---|---|
| Plant Output (net) | 220,000 kW |
| Heat Rate | 9,287 Btu/kWh (approximate) |

Distillate oil is suggested as an emergency and black-start fuel.

Main steam of 1175 psig, 952°F, has been selected for the steam cycle, based on a gas turbine exhaust temperature of 985°F. This design uses a 35°F approach temperature for the main steam, and falls in the range of readily available steam turbine generator sets. A 30°F approach temperature has been used on the feedwater heater, the economizer, and the evaporative sections in the steam generator. The steam turbine used for this design will be a full-condensing turbine, bottom-exhausting with the condenser mounted underneath.

The major process flows are shown in Figure 2.2. Combusted gas is expanded through the gas turbine, driving both the 74.5-MW generator and the integral free-shaft gas turbine air compressor on each unit. Exhaust gas from each turbine flows through multi-pressure HRSGs (one for each gas turbine), where the heat is utilized to help generate 1200 psig superheated steam used to drive the steam turbine generator, and 150 and 50 psig saturated steam for other plant uses. The gas is exhausted to the stack on exiting the steam generator. A bypass damper and stack are provided for each steam generator so that the combustion turbine can be operated independently of its HRSG.

The combined high-pressure steam flow of 775,780 lb/hr is expanded through a common steam turbine, driving a 100-MW generator, with 1175 psig, 952°F inlet conditions. Exhaust steam from the turbine is condensed in a vacuum condenser, which is cooled by the circulating water system employing a wet-dry cooling tower. The cooling tower can be operated in either a wet or dry mode, and is expected to operate in the dry mode during the winter months, eliminating the potential for fog plumes and icing about the tower, and reducing power plant makeup water requirements.

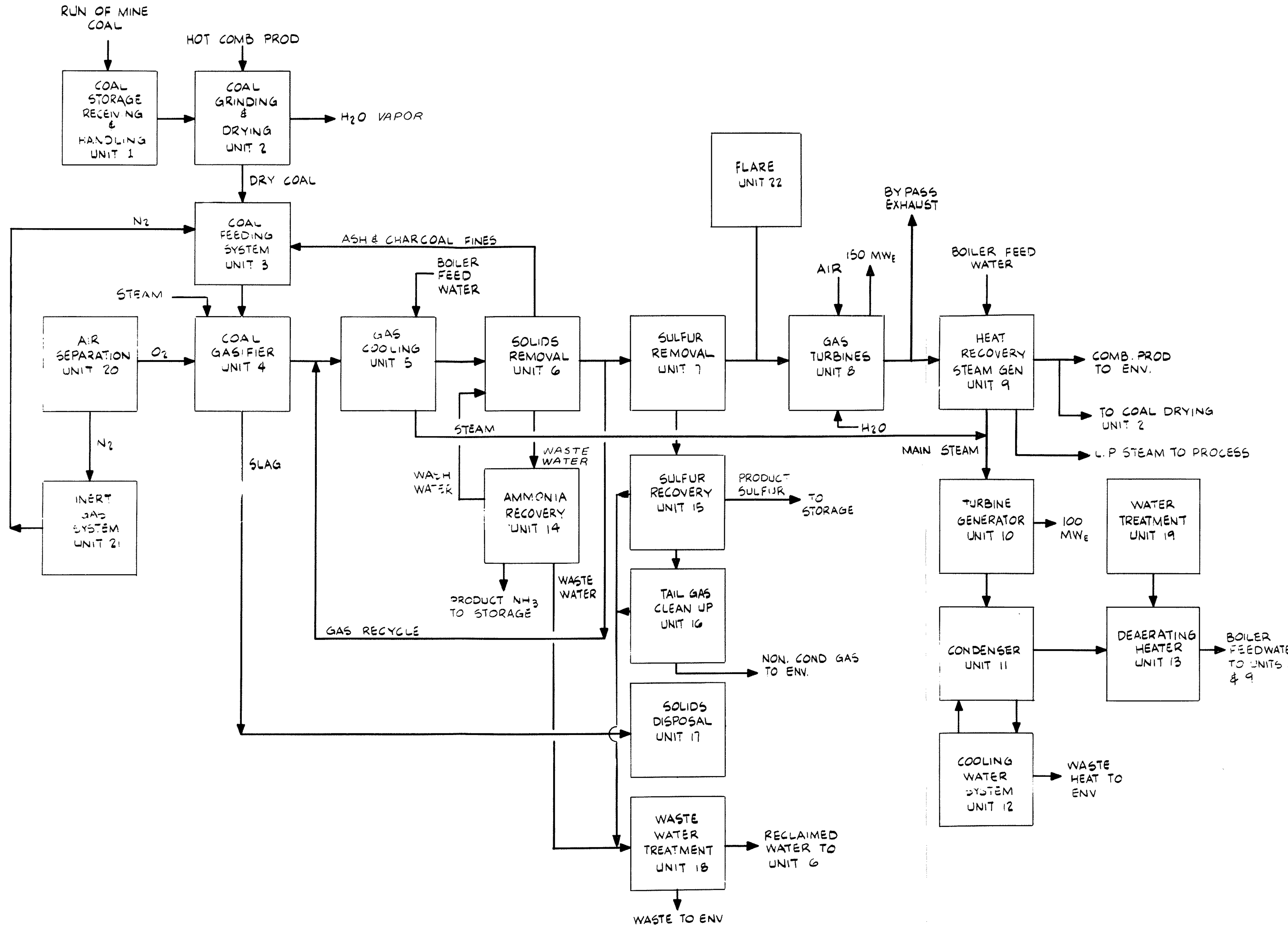



FIGURE 2.2. General Process Flow Diagram

The steam and feedwater system is an integrated plant design and is extremely complex. Saturated steam at three pressures, 50 psig, 150 psig and 1200 psig, is generated collectively by the HRSGs, the gas cooler heat exchanger, the feedwater heater, and various sulfur condensers and reaction boilers in the sulfur removal plant. The 50 psig saturated steam is used for feedwater deaeration and/or process steam in the effluent water strippers. The 150 psig saturated steam is used in the sulfur removal plant, with the condensate being returned to the deaerator tank. The 1200 psig saturated steam is superheated in the superheater section of each HRSG prior to use as main steam in the steam generators.

Condensate is pumped from the condenser to the condensate storage tank. Deaerator feed pumps take suction from the condensate tank, pumping the water through the low-pressure economizer sections of the HRSGs to the deaerator. Both the low-pressure and high-pressure boiler feed pumps take suction from the deaerator storage tank.

The low-pressure feed pump feeds the low-pressure evaporator sections of the HRSGs and provides the suction feed for the intermediate-pressure feed pump. A portion of the low-pressure feed pump discharge is fed through a sulfur condenser and reaction boiler in the sulfur plant where heat is absorbed; the heated water being returned to mix with the low-pressure saturated steam entering the deaerator. The 50 psig low-pressure saturated steam generated in the low-pressure evaporator sections of the HRSGs is used as deaerator feed and as process steam for the effluent water strippers.

The intermediate-pressure feed pump feeds the IP evaporator sections of the HRSGs, which produce 150 psig saturated steam. A portion of IP pump discharge is used as cooling water in the reaction boiler and sulfur condenser and the heated discharge is mixed with the 150 psig saturated steam entering the sulfur melter and reboiler. The 150 psig saturated steam is used exclusively in the sulfur melter and reboiler. Condensate from the sulfur melter and reboiler is fed back to the deaerator storage tank.

The high-pressure feed pump takes suction from the deaerator tank and discharges the water through heat exchangers in the gas cycle to the HRSG economizer sections. Part of the economizer outlet flows are fed to the gas cooler, generating saturated HP steam, which is collected in an independent steam drum. The remaining portion of the HP economizer outlets is fed to the HP evaporator sections of the HRSGs where saturated steam is produced. The saturated steam from the independent steam drum is passed through the gas cooler, producing superheated steam that is subsequently mixed with the steam from each HRSG, producing the high-pressure main steam for the steam turbine generator.

### 2.1.1 Gasifier Plant

Because of the requirement for load following capability, an entrained flow gasifier was selected. Fixed-bed gasifiers, such as Lurgi, and others, operate best at constant throughput and constant temperatures. Fluidized bed gasifiers, such as Westinghouse, could be considered if the time variation of the output were slow enough, i.e., the material residence time is about 15 minutes, so it would take times on the order of tens of minutes for the gasifier to respond to a change of fuel input. With entrained flow gasifiers, the particle residence times are small fractions of a minute. Since it is desirable to keep the rate of change of the steam power system components to about 5 percent per minute, both a fluidized bed gasifier and an entrained flow gasifier are potentially compatible. However, when considering the facility's intended application where it would be the largest generating plant within the utility grid system, it is desirable to have a more rapid response time to changes in system load. For this reason, an entrained flow gasifier was selected.

Because of the high moisture content of Beluga coal, 20 to 28 percent, the Shell system was selected. In the Shell system, the coal is fed as a dry powder through lockhoppers, rather than a coal-water slurry, which is used in the Texaco process. The extra water brought in with a coal slurry (approximately 50 percent by weight) combined with the moisture already contained in the coal would exceed process requirements and require more carbon to be combusted to heat the extra water vapor, thus reducing gasifier efficiency. The Shell gasifier has been piloted using a coal feed at a capacity of 150 tons/day, and similar units using residual fuel oil have been operated in the oil industry for a number of years. Two Shell units for gasifying coal are now being constructed in Europe at the thousand ton/day size, the basic module of a commercial plant. Both the Shell and Texaco units are approximately at the same level of development and demonstration at commercial scale. Therefore, selection of the Shell process over the Texaco process on the basis of feedstock moisture will have no adverse effect on the schedule of the proposed facility under study.

Another major design choice concerns the use of either an airblown gasifier to make low-Btu gas or an oxygen-blown gasifier to produce medium-Btu gas. This choice will ultimately be made on the basis of a detailed capital cost and operating cost estimate for the power plant. An airblown gasifier requires a larger physical size for the gas-flow-train components, a larger number of gasifier reactor vessels, larger product gas cleanup equipment and other components because of the substantial increase in mass flow (almost double) when air is used as the oxidant.

The use of oxygen requires an air separation plant to produce oxygen and the power to drive the separation plant. This power is generated by the plant's steam-bottoming cycle, and since the bottoming-cycle efficiency improves with size, the incremental cost for this power is less. In light of this and of the high cost of shipping and erecting equipment in Alaska, as well as the simplification in gasification plant start-up that can be achieved using previously liquefied and stored oxygen, the oxygen-blown gasifier was selected.

The production of medium-Btu gas as an intermediate product also permits the option of running the gasifier at 100 percent load all of the time and converting the excess MBG not required for electricity production to methanol. Methanol could be stored and used as a peak shaving fuel in the combustion turbines, or as a product for sale in commerce; the revenues received being used to offset the cost of generating electricity.

The following sections discuss the various components of the coal-gasifier combined-cycle plant in detail. Detailed process flow diagrams of the gasifier section and combined-cycle section are presented in Figures 2.3 and 2.4, respectively. Tables 2.1 and 2.2 present details of each flow diagram's process streams. Much of the following information regarding

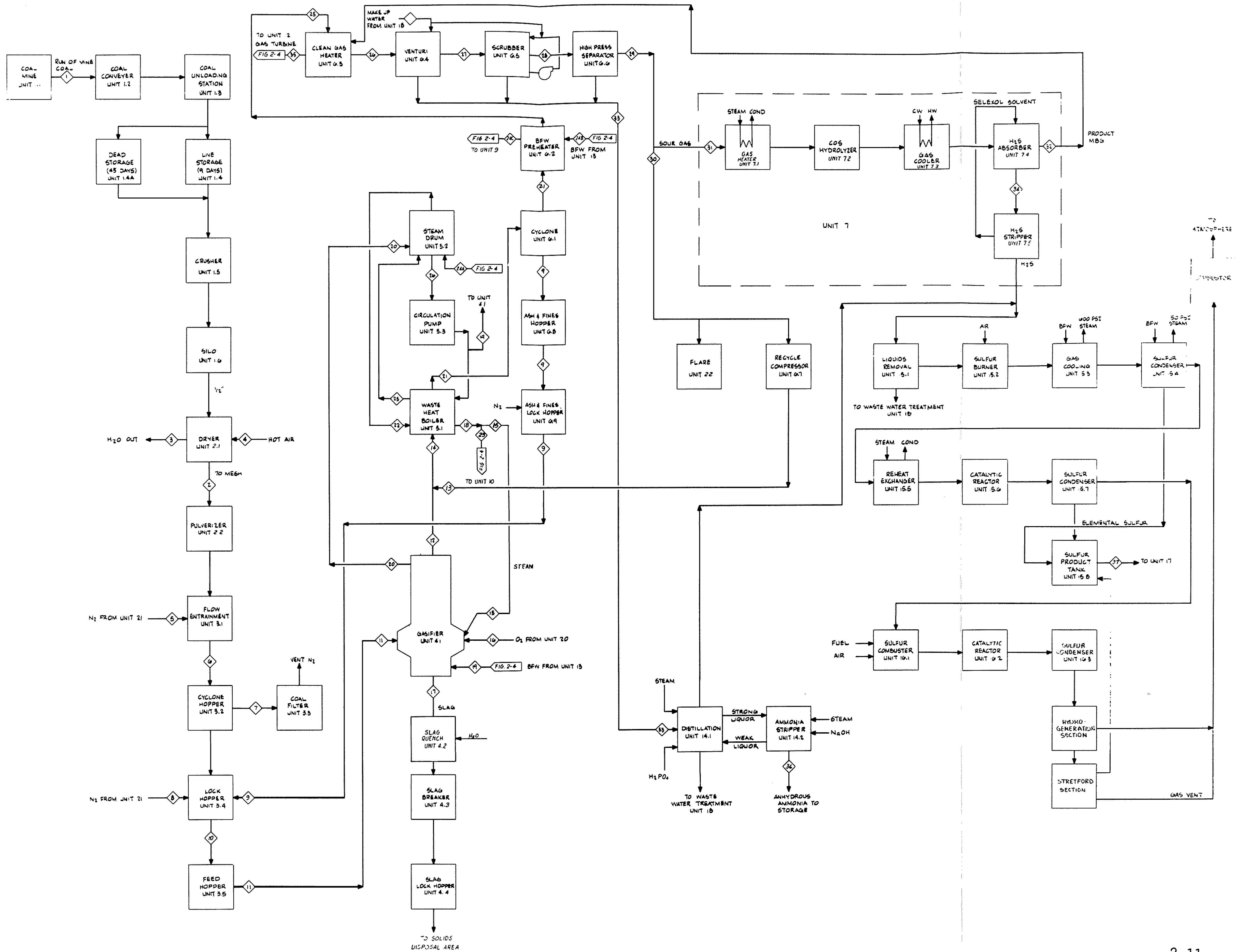



FIGURE 2.3. Gasifier Section: Process Flow Diagram

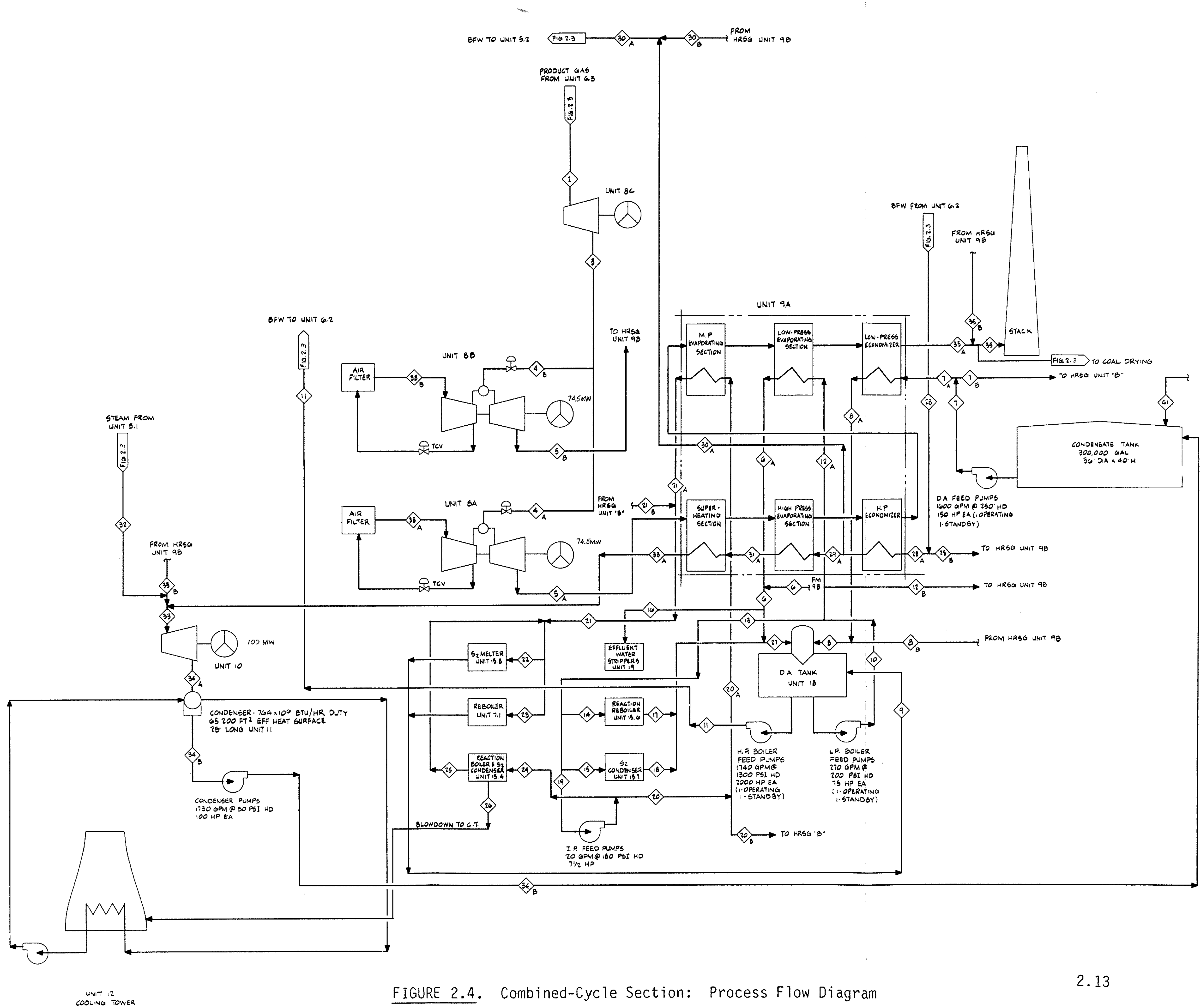



FIGURE 2.4. Combined-Cycle Section: Process Flow Diagram

## TABLE 2.1. Gasifier Section Flow Identification for Figure 2.3

| Stream | Fluid | Component | Input (lb/hr) | Pressure (psig) | Temperature (°F) |
|---|---|---|---|---|---|
| 1 | Raw Coal Feed | Raw Coal | 219,702 | atm | NA |
| 2 | Dry Coal Feed | Pulv. Coal | 162,580 | atm | |
| 3 | Water Vapor | $H_2O$ | 57,122 | atm | 300 |
| 4 | Hot Air | Air | | 1.1(atm) | 400 |
| 5 | Carrier Gas | $N_2$ | | 100 | 80 |
| 6 | Entrained Coal Flow | Coal, $N_2$ | | 2(atm) | |
| 7 | Separated Carrier Gas | $N_2$ | | | |
| 8 | Lock-Hopper Pressurization | $N_2$ | | 600 | |
| 9 | Fines Ash Recycle | Ash, Coal | | 600 | |
| 10 | Coal Feed | Coal | | 575 | |
| 11 | Coal Feed | Coal | | 550 | |
| 12 | Gasifier Product | CO, $H_2$, $H_2S$, Ash | | 450 | |
| 13 | Recycle Product Gas | CO, $H_2$, $H_2S$ | | 450 | |
| 14 | Mixed Raw Product Gas | CO, $H_2$, $H_2S$, Ash | | 450 | |
| 15 | Gasifier Steam | Steam | | 500 | |
| 16 | Oxygen | $O_2$ | | 500 | 200 |
| 17 | Slag | $Ca/SiO_2$ | | 450 | 2,400 |
| 18 | Superheated Steam | | | 1,275 | 940 |
| 19 | Reactor Cooling Water In | $H_2O$ | | 1,300 | 200 |
| 20 | Reactor Cooling Water Out | $H_2O$ | | 1,290 | |
| 21 | Raw Product Gas | CO, $H_2$, $H_2S$, Ash | | 440 | |
| 22 | Steam Drum Outlet | Steam | | | |
| 23 | Super Heated Steam | Steam | | 1,275 | 940 |
| 24 | Boiler Feedwater | $H_2O$ | | 1,300 | |
| 25 | Cooled Raw Gas | CO, $H_2$, $H_2S$ | | | |
| 26 | Cooled Raw Gas | CO, $H_2$, $H_2S$ | | | |
| 27 | Raw Gas | CO, $H_2$, $H_2S$ | | | |
| 28 | Raw Gas | CO, $H_2$, $H_2S$ | | | |
| 29 | Dried Raw Gas | CO, $H_2$, $H_2S$ | | | |
| 30 | Recycle Gas | CO, $H_2$, $H_2S$ | | | |
| 31 | Sour Product Gas | CO, $H_2$, $H_2S$ | | | |
| 32 | Product Gas | CO, $H_2$ | | 275 | 120 |
| 33 | Scrubber Waste Water | $H_2O$, $NH_3$ | | 300 | 220 |
| 34 | Selexol | | | 275 | 90 |
| 35 | Preheated Product Gas | | | 250 | 350 |
| 36 | Ammonia Product | $NH_2$ | | | |
| 37 | Sulfur Product | S | | | |

INTERCONNECTIONS

| | Stream | FIGURE 2.3 Unit No. | FIGURE 2.3 Stream No. | FIGURE 2.4 Unit No. | FIGURE 2.4 Stream No. |
|---|---|---|---|---|---|
| A | Product Gas | 6.3 | 35 | 8 | 3 |
| B | Main Steam | 5.1 | 23 | 10 | 32 |
| C | Comb Prod/Hot Air | 1.7 | 4 | 9 | 35 |
| D | Boiler Feed Water | 5.2 | 24A | 13 | 11 |
| E | Boiler Feed Water | 6.2 | 24B | 13 | 11 |
| F | Heated BFW | 6.2 | 24C | 9 | 28 |

TABLE 2.2. Combined-Cycle Section Flow Identification for Figure 2.4

| Stream | Fluid | Component | Input (lb/hr) | Pressure (psig) | Temperature (°F) | Enthalpy (Btu/lb) |
|---|---|---|---|---|---|---|
| 1 | High Pressure Product Gas | CO, $H_2$ | 290,000 | 425 | 330 | |
| 3 | Product Gas | CO, $H_2$ | 290,000 | 250 | 300 | |
| 4A+4B | Product Gas | CO, $H_2$ | 143,800 | 250 | 300 | |
| 5A+5B | Exhaust Gas | $CO_2$, $H_2O$ | 2,027,240 | | 1,000 | 278 |
| 6 | Low Pressure Steam | Steam | 39,120 | 50 | 298 | 1,179 |
| 6A+6B | Low Pressure Steam | Steam | 19,560 | 50 | 298 | 1,179 |
| 7 | Condensate | $H_2O$ | 787,320 | 108 | 110 | |
| 7A+7B | Condensate | $H_2O$ | 393,660 | 108 | 110 | |
| 8 | Water | $H_2O$ | 787,320 | | 200 | 168 |
| 8A+8B | Water | $H_2O$ | 393,660 | | 200 | 168 |
| 9 | Low Pressure Steam | Steam | 73,500 | 148 | 365 | 337.6 |
| 10 | Condensate | $H_2O$ | 119,420 | 200 | 250 | 218.5 |
| 11 | Boiler Feed Water | $H_2O$ | 775,780 | 1,300 | 250 | 218.5 |
| 12A+12B | Condensate | $H_2O$ | 19,560 | 200 | 250 | 218.5 |
| 13 | Condensate | $H_2O$ | 80,300 | 200 | 250 | 218.5 |
| 14 | Condensate | $H_2O$ | 5,040 | 200 | 250 | 218.5 |
| 15 | Condensate | $H_2O$ | 1,020 | 200 | 250 | 218.5 |
| 16 | Low Pressure Steam | Steam | 10,800 | 50 | 302 | 1,179 |
| 17 | Low Pressure Steam | Steam | 5,040 | 50 | 302 | 1,179 |
| 18 | Low Pressure Steam | Steam | 1,020 | 50 | 302 | 1,179 |
| 19 | Int. Pressure Feed Water | $H_2O$ | 74,240 | 200 | 250 | 218.5 |
| 20 | Int. Pressure Feed Water | $H_2O$ | 72,220 | 380 | 250 | 218.5 |
| 20A+20B | Int. Pressure Feed Water | $H_2O$ | 36,110 | 380 | 250 | 218.5 |
| 21 | Process Steam | Steam | 72,220 | 150 | 366 | 1,196 |
| 21A+21B | Process Steam | Steam | 36,110 | 150 | 366 | 1,196 |
| 22 | Process Steam | Steam | 500 | 150 | 366 | 1,196 |
| 23 | Process Steam | Steam | 73,000 | 150 | 366 | 1,196 |
| 24 | Boiler Feed Water | $H_2O$ | 2,020 | 380 | 250 | 218.5 |
| 25 | Process Steam | Steam | 1,280 | 150 | 366 | 1,196 |
| 26 | Blow Down | $H_2O$ | 740 | 50 | NA | NA |
| 27 | Low Pressure Steam | Steam | 34,380 | 50 | 298 | 1,179 |
| 28 | Boiler Feed Water | $H_2O$ | 775,780 | 1,275 | 310 | 1,183 |
| 28A+28B | Boiler Feed Water | $H_2O$ | 387,890 | 1,275 | 310 | 1,183 |
| 29A+29B | Boiler Feed Water | $H_2O$ | 161,800 | 1,250 | 550 | 549.1 |
| 30A+30B | Boiler Feed Water | $H_2O$ | 226,090 | 1,250 | 550 | 549.1 |
| 30 | Boiler Feed Water | $H_2O$ | 452,180 | 1,250 | 550 | 549.1 |
| 31A+31B | L. P. Steam | Steam | 161,800 | 1,200 | 569 | 1,183.2 |
| 32A+32B | L. P. Steam | Steam | 226,090 | 1,200 | 569 | 1,183.2 |
| 32 | L. P. Steam | Steam | 452,180 | 1,200 | 569 | 1,183.2 |
| 33A+33B | L. P. Steam | Steam | 387,890 | 1,175 | 952 | 1,472 |
| 33 | L. P. Steam | Steam | 775,780 | 1,175 | 952 | 1,472 |
| 34A | Condensate | $H_2O$ | 775,780 | 1.16 | 107 | 1,033 |
| 34B | Condensate | $H_2O$ | 775,780 | 36.5 | 107 | 75 |
| 35A+35B | Exhaust Gas | $CO_2$, $H_2O$ | 2,027,240 | 270 | NA | |
| 35 | Exhaust Gas | $CO_2$, $H_2O$ | 4,054,480 | 270 | NA | |
| 38A+38B | Comb Air | Air | 1,183,440 | atm | 80 | NA |
| 41 | Make Up Water | $H_2O$ | 27,440 | 50 | 60 | NA |

sulfur removal and recovery and tail gas cleanup has been modified from similar systems presented in Electric Power Research Institute (1978). Table 2.3 presents test data on the Shell-Koppers process using Wyodak, Wyoming, subbituminous coal, which is similar to Beluga coal. Data similar to this can be expected with the proposed design using Beluga coal.

Coal Gasification

The coal gasification section consists of a number of individual process units, including coal preparation, air separation, coal gasification and gas cooling, and ammonia recovery. Process descriptions of each unit follow and should be read in conjunction with the process flowsheet (Figure 2.3).

Coal Preparation (Figure 2.3, Units 1 and 2). The purpose of the coal preparation unit is to provide coal, sized smaller than 70 mesh without excessive surface moisture, for feeding to the gasification unit.

Coal Unloading Station--The type of coal unloading station required for the plant is dependent on the coal transportation system. For the purposes of this study, it is assumed that coal will be delivered to the site by mine-mouth conveyor. The mine-mouth conveyor will feed the storage pile directly. The conveyor will be sized for a capacity of 500 tons/hour. It will have a 35° troughing idler, be 36 inches in width, travel at a velocity of 350 feet per minute, and be weather protected its entire length.

Stacking and Reclaiming--Initial coal deliveries will be used to establish a compacted dead and long-term storage pile. This pile will consist of two sections, one on each side of a below-grade reclaim tunnel, and will contain a 45-day supply of coal for the plant. The V-shaped groove between the dead storage piles (over the reclaim tunnel) will be used for a live storage pile. The live storage capacity will be a 9-day supply for full-load operation.

Once the dead storage pile has been established and compacted, subsequent coal deliveries will be transported by an inclined/overhead conveyor tripper

TABLE 2.3. Typical Test Data from the Shell-Koppers Process Using Subbituminous Coal

Coal Feed Analysis

| | | |
|---|---|---|
| Carbon | percent by weight, as fired | 75.6 |
| Hydrogen | percent by weight, as fired | 6.0 |
| Oxygen | percent by weight, as fired | 16.8 |
| Sulfur | percent by weight, as fired | 0.9 |
| Nitrogen | percent by weight, as fired | 0.7 |
| Ash | percent by weight, as received | 35.0 |
| Coal | lower heating value, Btu/lb, as received | 7,380 |

Process Inputs

| Process Input | Units | $t/MMft^3$ Product Gas |
|---|---|---|
| Coal | As Received | 25.28 |
| Coal | As Fired | 15.26 |
| Oxygen | 99 percent by volume | 12.33 |
| Process Steam | | 0.37 |

| | |
|---|---|
| Gasification Efficiency (percent) | 83 |
| Thermal Efficiency (percent) | 97.5 |

Wet Synthesis Gas Composition (percent by volume)

| | |
|---|---|
| Water | 2.6 |
| Hydrogen | 32.5 |
| Carbon Monoxide | 62.8 |
| Carbon Dioxide | 1.3 |
| Methane | -- |
| Hydrogen Sulfide/ Carbonyl Sulfide | 0.3 |
| Nitrogen | 0.3 |
| Argon | 0.2 |

Source: Vogt and Van der Burgt (1980).

from the unloading hoppers to form the live storage pile. The traveling belt tripper will have a capacity of 500 tons/hour. It will be mounted on flanged wheels that engage parallel rails supported on either side of the belt. The tripper will be electric-motor-driven and will move continuously back and forth, reversing automatically at the ends of travel over the length of the live storage pile. The length of the traveling belt tripper will be 1400 feet.

The live storage pile should be covered with a corrugated, galvanized-sheet steel "A" frame roof. This structure will also support the overhead conveyor tripper enclosed in a penthouse at the apex of the roof. The cover will be 1400 feet long and 60 feet wide. The bottom edge of the roof will be 35 feet above grade and its apex will be 60 feet above ground level.

The entire coal storage pile (dead and live) will occupy an area of approximately 250 feet by 1500 feet, or 375,000 $ft^2$. The dead storage pile will be 25 feet high. The coal will be reclaimed in the concrete reclaimer tunnel below ground. Two 100 percent traveling rotary plow feeders will draw coal from the stack and discharge it onto a conveyor for transport to the plant. The reclaimer conveyor discharges to an inclined conveyor that will take the coal to the coal gallery. There, the coal will be transferred to conveyors feeding the plant silos. The inclined conveyor will consist of two 100 percent capacity conveyor belts in a weather-protected common enclosure. Each belt will have a capacity of 130 tons/hour. Dual capacity is provided to ensure that plant requirements can be met in the event any one conveyer is down. Provision is also made for metal detection, magnetic separation, automatic sampling, and weighing of coal.

Sampling--A coal sampling system will be provided. Detailed engineering will establish the exact location of the system, which may either be inside the plant or in a separate sample house in the yard.

Plant Storage--In-plant silo storage capacity will be 10 hours. The silos are situated above the pulverizers (mills) for gravity feed and will be provided with a fire protection system. Each silo will be designed for mass flow with stainless steel liners. They will be 24 feet in diameter and approximately 40 feet high. Each silo is sized for a capacity of 240 tons.

Pulverizers--The mills are located at the lowest elevation of the plant and serve to pulverize and dry the coal in preparation for feed to the gasifier. The mills are extremely large, heavy-duty, slow-speed, high-energy consuming machines. There will be a total of three mills, one under each silo. Hot air or combustion gases will be used to remove moisture from the coal. Each mill will have a capacity of 45 tons/hour and will pulverize the coal to 70 mesh sieve. The coal product is weighed and transported to the gasifier by bucket elevator.

Air Separation Plant (Figure 2.3, Unit 20). The air separation plant design is conventional, based on compression, air purification, and cryogenic separation of air into oxygen and nitrogen. A small amount of the nitrogen is used as inert gas for coal conveying and for tank blanketing; the remainder is vented. Air separation plant technology is available from several vendors as standard plant units.

The air separation unit will consist of two parallel plants, each designed for about 50 percent of the total oxygen demand of the gasifier plant, or about 1000 tons/day. Electric motor drives will be provided for the air compressors and oxygen compressors.

Coal Gasification and Gas Cooling (Figure 2.3, Units 3, 4, 5 and 6). The coal gasifier plant consists of a coal feed system, the coal gasifier (reactor), a fines separation system, and a heat recovery system. The design of the Shell coal gasification system is based on a modular concept, with two parallel gasifiers each sized for about 45 tons of coal per hour, or about 21 billion Btu/day. Use of two gasifiers provides several advantages:

- The building blocks form a pre-engineered, standardized plant that may be fully designed with all components identified and ready for procurement, thus reducing cost as well as the lead time required from commitment to installation.
- Reliability and capability for turndown of the overall plant are enhanced, since the individual gasifier units may be operated in various modes, and the shutdown of any one gasifier does not interrupt the operation of the complete system.

Each module train consists of coal and recycled fines lockhoppers, a gasifier, ash lockhoppers and conveyors, a gas quench scrubber/waste heat boiler, and a recycled gas cooler and compressor. The crushed, dried coal is conveyed pneumatically from the lockhoppers and injected through horizontal feed pipes using inert nitrogen gas as a transport medium. Oxygen is fed into the coaxial feed pipe to produce an oxygen-coal jet within the gasifier. Recycled gas is also fed at the exit of the gasifier to solidify the entrained slag particles before they enter the gas cooler. Fines and ash that are carried over from the reactor and gas cooler are collected in two cyclones in series, and the gas is cooled in a heat exchanger using boiler feed water. The fines and ash are recycled to the gasifier via the fines lockhopper.

The Shell Koppers design provides for gas heat recovery. The objective of the heat recovery system is to cool the product gas and to use the sensible heat recovered to generate electricity. Heat recovery starts with a waste heat boiler operating on the hot coal gas stream immediately after the gases leave the gasifier and have been quenched with recycle gas. The operating temperature of the heat exchanger metal surfaces is maintained below 900°F by the careful arrangement of heat sink streams.

The product gas passes through an ash and fines recovery cyclone, a feedwater heater and a clean gas regenerative heater, followed by quench cooling in a venturi quench scrubber feeding into a quench scrubbing column. The cooled gas is then split into two streams. One stream, representing about 43 percent of the flow, or 75 percent of the total gas produced, is compressed and recycled to the gasification process, while the remainder of the product gas is fed to the sulfur removal section. The water from the bottom of the gas scrubber contains ammonia, carbon dioxide, hydrogen sulfide, char fines, and ash fines, and is sent to the ammonia recovery section.

Ammonia Recovery (Figure 2.3, Unit 14). The purpose of this process unit is to recover the ammonia produced from the nitrogen entering the gasification unit with the coal and oxygen, and to clean the water so it can be recycled back to the venturi scrubber.

The water from the venturi scrubber, which generally exhibits high ammonia concentrations, is decanted in a settling tank to remove most of the ash fines and then filtered and pumped to an ammonia removal column. The underflow solids from the settling tank are removed via a slurry pump, dewatered and disposed of with the slag.

The ammonia removal column concentrates the ammonia in an aqueous solution that is suitable for distribution as fertilizer. This aqueous ammonia is further processed using the Phosam-W-Process (licensed by U.S. Steel Corp.) for conversion to anhydrous ammonia with the water recycled to the venturi scrubbing system.

The quantity of ammonia produced as byproduct from the gasification depends largely upon the nitrogen content of the coal and the temperature of gasification. For this process, the ammonia produced should be between approximately 65 to 75 percent of the nitrogen in the coal (0.6 percent by weight) or approximately 0.42 percent (by weight) of the coal. The final selection of the process design depends upon an assessment of the market for the ammonia.

Gas Cleanup Section

The product gas preparation section consists of the following process units: sulfur removal, sulfur recovery, and tail gas cleanup. Descriptions of these units follow.

Sulfur Removal (Figure 2.3, Unit 7). This unit consists of a hydrolysis subsystem for carbonyl sulfide (COS) conversion and an absorber section for hydrogen sulfide ($H_2S$) removal. The hydrolysis subsystem is designed to convert COS to $H_2S$ by hydrolysis and reduce the sulfur in the gasifier product to 10 ppm, which is suitable for methanol synthesis. The system consists of a gas preheater, a catalytic converter containing a hydrolysis catalyst (Topsoe CKA or equivalent) that converts the COS present in the gas to $H_2S$, and a gas cooler. Provisions are made to adjust the steam-to-gas ratio in the process gas because the conversion of COS to $H_2S$ over the catalyst is favored by low temperature and a high steam-to-gas ratio.

From the hydrolysis unit the gas passes to a Selexol Scrubbing System (a proprietary Allied Chemical process designed to selectively remove sulfur from the gasifier product). In the absorber the gas is counter-currently contacted by a stream of lean Selexol solvent, which is a physical solvent consisting of the dimethylether of polyethylene glycol.

Selexol can absorb approximately 9 times as much $H_2S$ as carbon dioxide ($CO_2$) under similar conditions of temperature, pressure, and solvent loading. This property makes it possible to remove $H_2S$ to low levels, while retaining $CO_2$ in the gas (The $CO_2$ provides some advantages when medium-Btu gas is to be used as fuel for combustion turbines).

The absorber-bottom liquid is flashed in a flash drum to recover absorbed hydrogen ($H_2$) and carbon monoxide (CO). The flashed gas is recycled by a recycle compressor to the absorber feed. Solvent from the flash tank is heated by exchange with solvent in the solution exchanger and passes to the stripper, where the acid gas is stripped from the solvent by steam. The acid gases in the stripper overhead are cooled in the stripper condenser and water is separated in the reflux drum, from which it is pumped back to the stripper. The acid gases flow to the sulfur recovery unit for further processing.

A steam-heated reboiler is provided to generate stripping steam. From the bottom of the stripper, lean regenerated solvent is pumped through the leanrich solution exchanger and then cooled by refrigerant in the solution cooler before returning to the absorber to complete the cycle.

Sulfur Recovery (Figure 2.3, Units 15 and 16). The sulfur recovery unit consists of two sections to insure that the sulfur recovery system is adequate to meet the potential range of sulfur in the coal. The first section consists of a train of modified Claus-type units that convert most of the $H_2S$ produced to elemental sulfur. The tail gas from the Claus units is further processed in a sulfur recovery unit (such as a Beavon unit or equivalent). For coals with a sulfur content of less than 0.5 percent, such as Beluga coal, it may be possible to eliminate the Claus section and use a modified Beavon-Stretford sulfur removal system.

The conversion of $H_2S$ to sulfur (S) in a Claus unit is based on the reaction between $H_2S$ and sulfur dioxide ($SO_2$), in which $H_2S$ reacts with $SO_2$ to form S and water ($H_2O$) according to the following reaction:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

Part of the $H_2S$ is usually burned with air to provide the $SO_2$ required; however, in this plant this does not provide sufficient $SO_2$ needed for the above reaction due to the low sulfur content of Beluga coal. Some sulfur is therefore burned to produce $SO_2$, and this is recycled to the process. Combustion air to the sulfur combustion unit is supplied by an air blower, and the combustion gas containing $SO_2$ is cooled by generating medium-pressure steam. The gas then passes to the first sulfur condenser, where it is cooled by generating additional low-pressure steam. The $SO_2$-rich gas is combined with the $H_2S$-rich acid gas at this point and is then reheated in the first reheater before entering the first catalytic reactor, where $H_2S$ and $SO_2$ react over a catalyst to form free sulfur.

Most of the sulfur is produced in the first catalytic reactor from which the gas flows to a sulfur condenser where the sulfur is condensed and drained to a sulfur product tank. To obtain the desired degree of conversion, this process is repeated in the second and third reactor stages, which have similar reheaters, catalyst converters and condensers (third stage not shown in Figure 2.3). The tail gas from the final condenser goes to the tail gas sulfur recovery unit. All sulfur that is produced drains into the sulfur product tank from where it is distributed to disposal by a steam-traced pipeline. The sulfur used to produce $SO_2$ is recycled to the same pit.

The tail gas cleanup unit provides for the final cleanup of the vent gases from the sulfur recovery process, which contain some sulfur as $SO_2$, S, and $H_2S$. The selected process is the Beavon-Stretford sulfur removal process that consists of two sections: a hydrogenation section to convert sulfur compounds including free sulfur to $H_2S$, and a Stretford section to oxidize the $H_2S$ in an aqueous solution to elemental sulfur. The elemental sulfur is floated from the solution and then melted and sent to the Claus unit sulfur product tank.

The hydrogenation section consists of a feed preheater, a hydrogenation reactor and reactor effluent cooler that generates steam. The tail gas is mixed with a reducing gas produced by the partial combustion of process waste fuel gas, and the mixture flows to the hydrogenation reactor, where the hydrogenation and hydrolysis reactions take place converting all COS, carbon disulfide ($CS_2$), $SO_2$, and S into $H_2S$.

The hydrogenated tail gas is cooled in the reactor effluent cooler by generating low-pressure steam, and then flows to the Stretford oxidation unit. This unit consists of a venturi scrubber, absorber, oxidizer tank, and sulfur separation and melting equipment.

The cooled tail gas is first contacted with oxidized Stretford solution in the venturi scrubber, where most of the $H_2S$ is absorbed. The gas and solution from the venturi gas scrubber discharge into the bottom section of the absorber and the gas passes counter current with fresh oxidized Stretford solution to the top of the absorber, where the cleaned and treated tail gas is vented to the atmosphere. A combustor is provided in the vent line from the absorber to burn any untreated $H_2S$ and other combustibles in case of a shutdown of the Stretford section.

The bottom of the absorber is sized to allow sufficient residence time for the sulfide oxidation reaction to go to completion according to the following overall reaction:

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O$$

The solution from the absorber flows to the oxidizer tank where the solution is aerated. Sulfur slurry overflows from this tank into the sulfur slurry tank and the oxidized solution flows to the balance tank, from where it recycles back to the venturi gas scrubber and absorber. A cooling tower and circulating water pump are provided with the balance tank to maintain heat and water balances of the unit.

The sulfur slurry that flows to the slurry tank is agitated gently to become deaerated and is then pumped to the sulfur melter. The hot dilute solution and molten sulfur flow to the sulfur decanter where the sulfur and solution separate. The sulfur is withdrawn from the bottom of the decanter and flows to the Claus unit sulfur pit. The hot solution is released from the top of the decanter, and returns to the balance tank after being quenched with a stream of cool recycle solution.

Ancillary Systems and Utilities

The principal ancillary systems supporting the operation of the process units discussed in previous sections are: 1) the inert gas system, and 2) flare headers, flares, and safety equipment.

Inert Gas System. The inert gas system includes provisions for coal conveying, tank safety blanketing, process purging operations, and safety uses. The nitrogen obtained from the air separation plant section is used as the source of inert gas. A storage volume is provided for surges and startup of the plant.

Flare Headers, Flares, and Safety Equipment. This unit includes the distributed system of process unit relief valve flare headers, process vent headers, the flare stacks and their ignition systems, and any liquid knock-out vessels and pumps associated with it. As part of this unit are the safety equipment and systems for firefighting, including firefighting tanks and pumps, monitors and interconnecting pipelines. The underground process and storm water drain system is part of this unit.

### 2.1.2 Combined-Cycle Plant

The combined-cycle plant consists of two gas turbine generators rated at approximately 74.5 MW each in combination with a steam turbine rated approximately 100 MW (Figure 2.4). The three turbines, together with the two heat recovery steam generators (one steam generator for each gas turbine) and other required auxiliary equipment, are housed in a common building approximately 185 feet wide x 300 feet long and 90 feet high. The building will be of steel construction with aluminum-sandwiched insulation siding, and will be served by an overhead crane.

## Combustion Turbines

Each combustion turbine is a large-frame industrial-type with an axial flow multi-staged compressor and power turbine on a common shaft. The combustion turbine is directly coupled to an electric generator, and can be started, synchronized, and loaded in about one-half-hour under normal conditions.

Each combustion turbine/generator package also includes an inlet air filtration system, fuel system, water injection system, lube oil cooling, and various minor subsystems as required and furnished by the manufacturer. Combusion turbine/generator design parameters are presented in Table 2.4.

The inlet air filter is a high-efficiency fixed-media-type suitable for removing particulates from the inlet air. The use of an evaporative cooler has not been anticipated because of the low air temperatures in Alaska, but a cooler could be added later if further study justifies the expenditure.

The fuel system includes the fuel-oil forwarding skid and the fuel-gas metering equipment. The combustion turbine is furnished with one liquid and one gas fuel nozzle in each of the 10 annular combustors. One nozzle will be sized for the medium-Btu coal gas and the other nozzle will be sized for distillate oil. Liquid fuel is pumped from the fuel forwarding skid to the combustion turbine, where a high-pressure pump forwards the fuel to the fuel nozzles. Gaseous fuel must be furnished to the combustion turbine at about 250 psig.

The water injection system is used to limit the emissions of oxides of nitrogen ($NO_x$). Water is pumped from the demineralized water storage tank and injected directly into the combustors. This limits the peak flame temperature, which in turn limits the formation of thermal $NO_x$. The injection rate is a function of load, ambient temperature, and the type of fuel. Typical water injection rates at base load are about 50 gpm per engine. Demineralized water is required to limit formation of deposits on the turbine blades.

Other miscellaneous systems furnished with the combustion turbine include: the starting package complete with electric motor and torque

TABLE 2.4. Combustion Turbine with Generator Design Parameters (Based on General Electric MS7001E or Equal)

Number: Two required

Turbine Type: Simple-cycle, single-shaft, three-bearing.

Generator Type: Hydrogen-cooled unit rated 110 MVA at 13.8 kV, 0.9 pf with 30 psig hydrogen pressure at 10°C.

Performance: (Each Turbine)

| | |
|---|---|
| Base Rating | 74,450 kW at ISO Conditions (59°F, Sea Level) |
| Heat Rate (LHV) | 10,655 Btu/kWh |
| Air Flow | 597 lb/sec |
| Turbine Exhaust Temperature | 985°F |
| Turbine Inlet Temperature | 1985°F |
| Inlet Pressure Drop | 5 in. water |
| Exhaust Pressure Drop | 10 in. water |
| Dimensions (turbine generator only) | 29 ft wide by 70 ft long by 13 ft high |

Combustion Turbine Features:

Accessory compartment complete with starting motor, motor control center for all base-mounted motors, lubrication system, hydraulic control system, atomizing air system, and cooling water system.

Excitation compartment complete with static excitation equipment.

Switchgear compartment complete with generator breaker, potential transformers, disconnect link for auxiliary feeder, and a customer power takeoff.

Fuel system capable of utilizing medium-Btu gas or liquid fuel.

Fire protection system (low-pressure $CO_2$).

$NO_x$ control system utilizing water injection.

converter; a lube oil system for bearing lubrication; a cooling water system for cooling the lube oil system; a $CO_2$ system for fire protection and generator purge; and a controls system for controlling the entire gas turbine generator package.

The combustion turbines are normally operated from a central control room, but controls provided with the unit allow either local or remote unattended operation. Operation of the combustion turbines is essentially an automated process, but operator presence is required to achieve proper coordination with boiler control functions. Under normal conditions, all combustion turbines are in operation at their baseload rating.

Heat Recovery Steam Generators (HRSGs)

The high-pressure steam for the steam turbine generator will be generated in the two HRSGs and the coal gas cooler. The coal gas cooler will serve as part of the evaporator section for both steam generators, utilizing part of the economizer outlet flows as feed and generating saturated steam in a separate steam drum. The saturated steam from the separate drum is fed back to the gas cooler producing superheated steam that is then mixed with the steam from each HRSG producing high-pressure main steam for the steam turbine generator (Figure 2.4). All low- and intermediate-pressure sections are similarly independent.

The HRSGs are physically housed together with the gas turbines, on a one-for-one basis. The HRSG package includes the steam generator complete with ductwork from the combustion turbine to the steam generator, a bypass damper and bypass stack, and a steam generator exhaust stack. During startup and other load conditions, the bypass damper may be operated to provide the required flexibility. By closing the bypass damper, the combustion turbine exhaust is routed to the stack and does not reach the steam generator.

The HRSGs are the dual pressure design type with a nominal main steam outlet pressure of 1200 psig at 900°F, intermediate-pressure saturated steam at 150 psig and low-pressure 50 psig saturated steam. Specific design loads for each section of the HRSG are defined in Table 2.5. The HRSGs are designed for continuous operation.

TABLE 2.5. Heat Recovery Steam Generator Design Parameters

Number: Two required

Type: Watertube, forced-circulation (General Electric) or two-drum natural-circulation (Deltak or Henry Vogt), dual-pressure.

Performance: Steam Generation in the HRSGs is integrated with steam generation from other sources. The HRSGs will be designed with independent sections as listed below.

| Section | Flow (lb/hr) | Outlet Pressure (psig) | Inlet Temperature (°F) | Outlet Temperature (°F) |
|---|---|---|---|---|
| LP Economizer | 393,660 | 108 | 110 | 200 |
| LP Evaporator | 19,560 | 50 | 250 | Sat. Steam |
| IP Evaporator | 72,220 | 150 | 250 | Sat. Steam |
| HP Economizer | 387,890 | 1250 | 310 | 550 |
| HP Evaporator | 161,800 | 1200 | 550 | Sat. Steam |
| HP Superheater | 397,890 | 1175 | 569 | 952 |

All steam generator controls will be located in a common area in the central control room.

Steam Turbine Generator

The main steam from the HRSGs is conveyed to a common turbine generator set rated a nominal 100,000 kW. The turbine generator will be a direct-connected multivalve, multi-stage condensing unit, mounted on a pedestal with a bottom exhaust for mounting the condenser under the turbine. Design parameters for the turbine generator are shown in Table 2.6. The turbine generator set will be furnished complete with lube oil and electrohydraulic control systems as well as the gland seal system and the generator cooling and sealing equipment.

The turbine generator will be located on a pedestal at one end of the combined-cycle plant building. In addition to the combustion generators, steam generators, steam turbine and condenser, the building will also contain

TABLE 2.6. Steam Turbine Generator Unit Design Parameters

| | | |
|---|---|---|
| Number: | One required | |
| Turbine Type: | Multistage, straight-condensing, bottom exhaust | |
| Generator Type: | Hydrogen-cooled unit rated 100 MW at 18 kV, 0.9 pf with 30 psig hydrogen pressure at 10°C | |
| Performance: | Base Rating | 100 MW |
| | Steam Inlet Pressure | 1175 psig |
| | Steam Inlet Temperature | 952°F |
| | Exhaust Pressure | 2 to 4" hg |
| | Exhaust Temperature | 92°F |
| | Speed | 3600 rpm |
| Features: | Common-base-mounted with direct-drive couplings. Accessories include multiple inlet control valves, electric hydraulic control system, lube oil system with all pumps and heat exchangers for cooling-water hook-up, gland steam system and generator cooling. Excitation compartment complete with static excitation equipment. Switchgear compartment complete with generator breaker potential transformers. | |

the feedwater pumps, condensate pumps, vacuum pumps, feedwater deaerator, instrument and service air compressors, motor control centers, control room, house boiler and diesel generator. The house boiler will be sized to provide building heating and freeze protection to all exposed equipment. The diesel generator will be sized for black startup service.

### Condenser

The condenser design will be single-shell, two-pass, with a divided water box and hotwell. The hotwell will be designed to have sufficient storage to allow proper level control for surging and shall be properly baffled to keep the condensate at saturation temperature.

Tube sheets will be Muntz metal, with inhibited Admiralty tubes, except for 70-30 copper nickel tubes in air removal sections and impingement areas. The condenser design data are listed in Table 2.7.

TABLE 2.7. Condenser Design Parameters

| | | |
|---|---|---|
| Number: | One required | |
| Condenser Type: | Single-Shell - 2-pass | |
| Performance: | Heat Load | $764 \times 10^6$ Btu/hr |
| | Saturation Temperature | 92° (1.5" Hg) |
| | Inlet Water Temperature | 72°F |
| | Outlet Water Temperature | 87°F |
| | Terminal Temperature Differential | 5°F |
| | Cooling Water Flow | 102,000 gpm |
| Features: | Single-shell, 2-pass - 1" - 18 gage Admiralty Tubes | |
| | Divided water box and hotwell | |

Cooling Tower

The cooling tower shall be the wet-dry type mechanical draft design of material most suitable for the cold weather conditions found in the Beluga area (see Table 2.8).

Three 50-percent-capacity vertical pit-type circulating water pumps will be mounted in an enclosure at the cooling tower basin. The pumps will be mounted 4 feet above the water level and have self lubricating, cutless rubber design shaft bearings (see Table 2.9).

Other Major Equipment

Design parameters for other required equipment are shown in Tables 2.10 and 2.11.

### 2.1.3 Electric Plant

Two types of prime movers are utilized for electrical generation (see Figure 2.5), including two gas-fired combustion turbines with generators rated 74.5 MW each and one steam turbine generation unit rated at 100 MW. Each gas turbine will deliver approximately 80 MVA to the switchyard. The steam

TABLE 2.8. Wet-Dry Cooling Tower Design Parameters

| | | |
|---|---|---|
| Number: | One required | |
| Type: | Parallel Path Wet-Dry | |
| Performance: | Heat Load | $836 \times 10^6$ Btu/hr |
| | Cooling Water Flow | 112,000 gpm |
| | Inlet Water Temperature | 87°F |
| | Outlet Water Temperature | 72°F |
| | Design Basis - 15°F approach to 10 percent of the time wet bulb temperature of 57°F at Anchorage. Design coldest dry bulb (97.5 percent of time) is 20°F at Anchorage. | |
| Features: | One fan required for each cell. Integral air-cooled heat exchanger sections for "dry" cold weather use. | |

turbine will add 90 MVA, resulting in a total of 250 MVA delivered to the switchyard. The coal gasifier plant will use approximately 30 MVA of this total, resulting in 220 MVA for export.

Combustion Turbine Generators

These are "packaged" units and as such include all equipment required to support the turbine generator. The generators are nominally rated at 74.5 MW, 0.9 pf, 83 MVA, with generation voltage at 13.8 kV.

The package generally includes:

(a) 13.8-kV switchgear that houses the generator grounding transformer and generator air-circuit breaker.

(b) Non-segregated phase bus duct runs to the generator and main transformer.

(c) A master control panel for overall operation and monitoring.

(d) A unit auxiliary transformer, 13.8/4.16 kV, sized to support the ancillary load (assumed to be 2 MVA).

(e) A 4.16-kV switchgear with air-circuit breakers for other loads (e.g., 800-hp cranking motor). The largest load is fed from the plant common 4.16-kV switchgear.

The step-up transformers for each gas turbine are rated 80 MVA, 13.8/138 kV.

## TABLE 2.9. Pump Design Parameters

Feed Pumps

| | | | |
|---|---|---|---|
| Number: | | Two required | |
| Type: | | Horizontal split-case, multistage, double-suction, frame-mounted, complete with electric motor drive and lube oil system. | |
| Performance: | (each pump) | Capacity | 1740 gpm (100 percent plant capacity) |
| | | TDH | 3168 ft at 250°F |
| | | NPSH | 20 to 24 ft |
| | | Motor | 2000 hp |

IP Feed Pumps

| | | | |
|---|---|---|---|
| Number: | | Two required | |
| Type: | | Horizontal, single-stage centrifugal, frame-mounted, complete with motor drive. | |
| Performance: | (each pump) | Capacity | 20 gpm (100 percent plant capacity |
| | | TDH | 870 ft |
| | | Water Temp. | 250°F |
| | | Inlet Press | 200 psig |

LP Feed Pumps

| | | | |
|---|---|---|---|
| Number: | | Two required | |
| Type: | | Horizontal, multistage centrifugal, double-suction frame-mounted, complete with motor drive | |
| Performance: | (each pump) | Capacity | 270 gpm (100 percent plant capacity) |
| | | TDH | 480 ft |
| | | Water Temp. | 250°F |
| | | NPSH | 10 to 12 ft |

Condensate Pumps

| | | | |
|---|---|---|---|
| Number: | | Three required | |
| Type: | | Vertical-shaft single-stage centrifugal, complete with vertical mounted motor. | |
| Performance: | (each pump) | Capacity | 825 gpm (50 percent plant capacity) |
| | | TDH | 150 ft |
| | | Water Temp. | 120°F |
| | | NPSH | Vacuum |

Deaerator Feed Pumps

| | | | |
|---|---|---|---|
| Number: | | Two required | |
| Type: | | Horizontal, single-stage centrifugal-mounted, complete with motor drive | |
| Performance: | (each pump) | Capacity | 1600 gpm (100 percent plant capacity) |
| | | TDH | 150 ft |
| | | Water Temp. | 110°F |

Cooling Water Circulating Pumps

| | | | |
|---|---|---|---|
| Number: | | Three required | |
| Type: | | Vertical shaft pit pumps with submerged suction, discharge column complete with vertical-mounted electric motor. | |
| Performance: | (each pump) | Capacity | 66,000 gpm (50 percent plant capacity) |
| | | TDH | 45 ft |
| | | Water Temp. | 40 to 80°F |
| | | Submerged Suction | |

TABLE 2.10. Fuel Oil and Condensate Tank Design Parameters

| | |
|---|---|
| **Condensate Tank** | |
| Number: | One required |
| Type: | Fixed roof - carbon steel |
| Size: | 150,000 gals (approx. 5-day supply) |
| Service: | Condensate storage |
| Features: | Steam heating coils, suitable insulation, plastic-lined |
| **Deaerator and Storage Tank** | |
| Number: | One required |
| Type: | Integral connected unit with deaerator mounted on top of 5 min-storage tank. Stainless steel troughs and baffle plates. |
| Size: | 39,370-lb storage |
| Water Flow Out: | 472,400 lb/hr |
| Steam Flow In: | 50 psig |
| Design Pressure: | 60 psig |
| Operating Pressure: | 25 psia |
| **Fuel Oil Tanks** | |
| Number: | Two required |
| Type: | Floating roof |
| Size: | 89,580 BBL<br>5 - 96" courses, 120 ft diameter x 40 ft high. |
| Service: | Distillate oil, specific gravity of 0.82 - 0.86 |
| Features: | Stairway, platform, floating roof seal, fixed roof supports |

TABLE 2.11. Miscellaneous Equipment Design Parameters

Air Compressors

| | |
|---|---|
| Number: | Two required |
| Type: | Reciprocating, single-cylinder, oil free, water-cooled, frame-mounted with motor. |
| Performance: | 50 actual cubic feet per minute (ACFM) each 115 psig discharge pressure |

Diesel Generator

| | |
|---|---|
| Number: | One required |
| Type: | Air-start, skid-mounted, multicylinder diesel, complete with 1-1/2-MW generator, 0.8 pf |

Heating Steam Boiler

| | |
|---|---|
| Number: | One required |
| Type: | Fire-tube forced-draft Scotch Marine-type. |
| Performance: | 40,000 lb/hr<br>50 psig saturated |

Steam Turbine Generator

The generator is rated 100 MW, 0.9 pf, 110 MVA, with generation voltage at 18 kV. The unit auxiliary transformer is three-winding 20 MVA, 18-4.16/4.16 kV. The two secondary windings supply 4.16-kV busses 3A and 3B. The step-up transformer is rated 90 MVA 18/138 kV.

Station Service Transformer

This transformer is used to supply power for the steam turbine generator auxiliaries required for startup and to provide power for the coal handling areas, oxygen, and gasifier plants. It is a three-winding, 30-MVA, 138-4.16/4.16-kV transformer. The two secondary windings feed 4.16-kV common switchgear

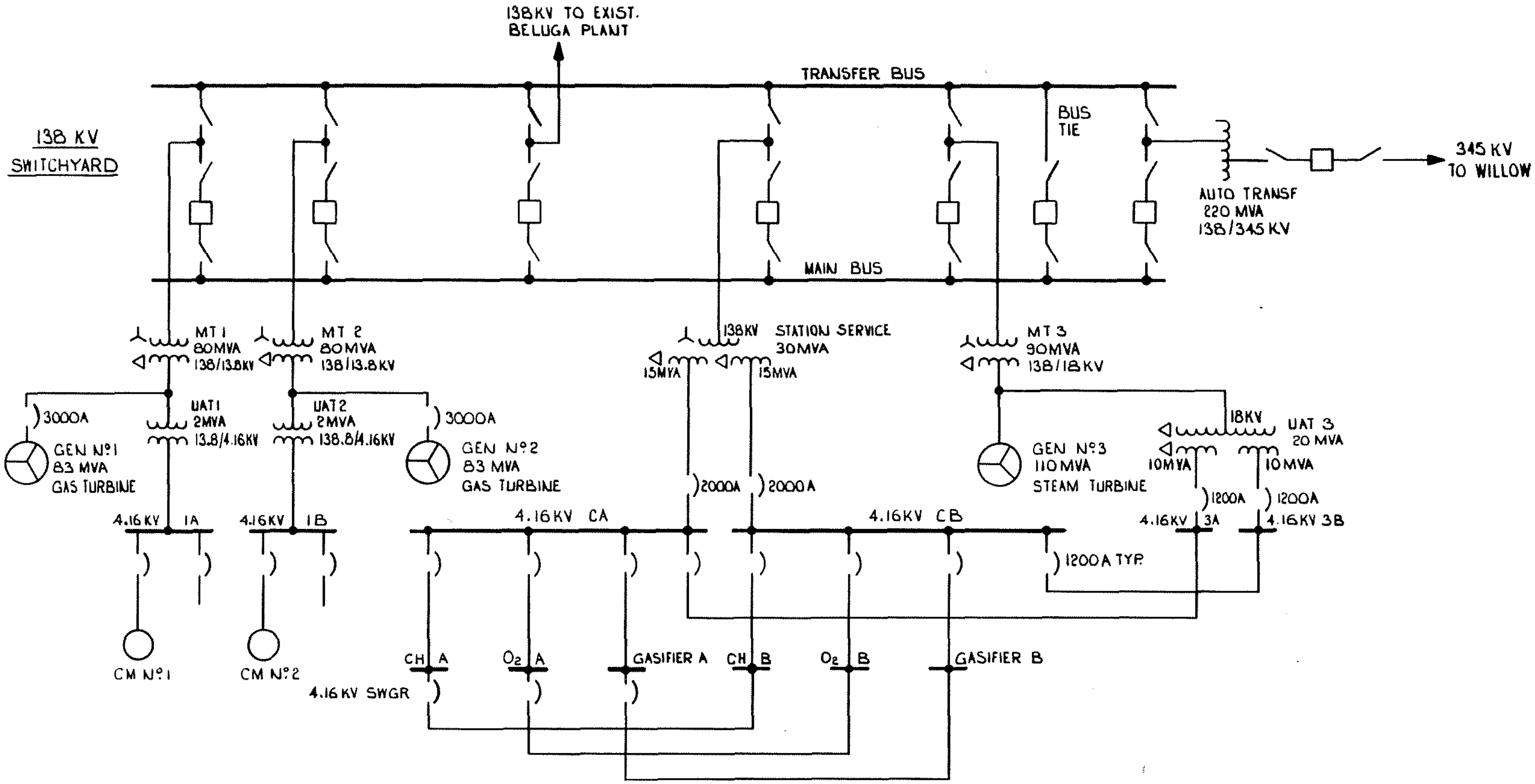



FIGURE 2.5. One-Line Diagram

buses A and B. The 4.16-kV Busses CA and CB supply dual switchgear trains A and B for the following:

4.16-kV coal handling switchgear A and B

4.16-kV oxygen plant switchgear A and B

4.16-kV gasifier switchgear A and B

In addition, ties to the steam turbine 4.16-kV switchgear 3A and 3B (Steam Turbine Startup Supply) are fed from this bus.

Switchyard

The switchyard is basically 138 kV consisting of seven bays, as shown in Figure 2.6. One parameter for selecting this voltage was the inclusion of a tie line to the existing Beluga Station, which at present has a 138-kV tie line to Anchorage.

The switchyard is a two-bus arrangement, with a main and a transfer bus. Each bay has a 138-kV circuit-breaker, three disconnect switches and a 138-kV tower. The bus tie bay has a 138-kV circuit-breaker and two disconnect switches. The transmission voltage is 345 kV for export of approximately 220 MVA. An autotransformer, 345-kV circuit-breaker and two disconnect switches comprise this portion.

### 2.1.4 Water and Wastewater Treatment Systems

Various water and wastewater treatment facilities will be incorporated into the plant design to produce appropriate unit makeup water and permit the reuse of process water. The facilities that will be required for this station are briefly described below. The anticipated water balance diagram is presented in Figure 2.7.

Makeup Water Treatment System

The makeup water treatment system is a multicomponent system comprised of pretreatment and demineralization sections. It is designed to provide demineralized water for steam-cycle makeup, including boiler blowdown, reaction hydrolysis water and injection for $NO_x$ control. It also supplies the system reservoir for potable, and heating, ventilating and air-conditioning

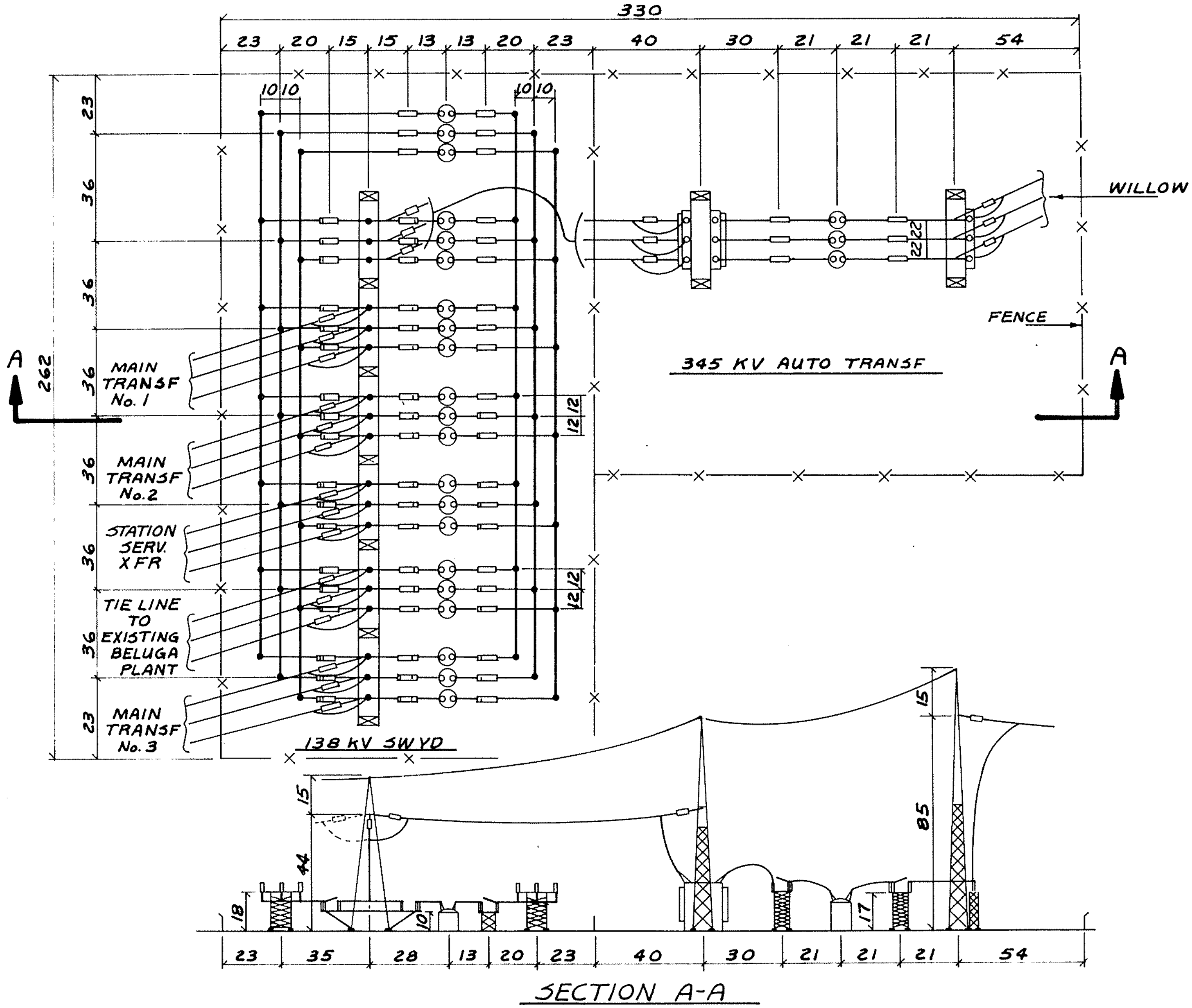



FIGURE 2.6. Beluga Station Switchyard

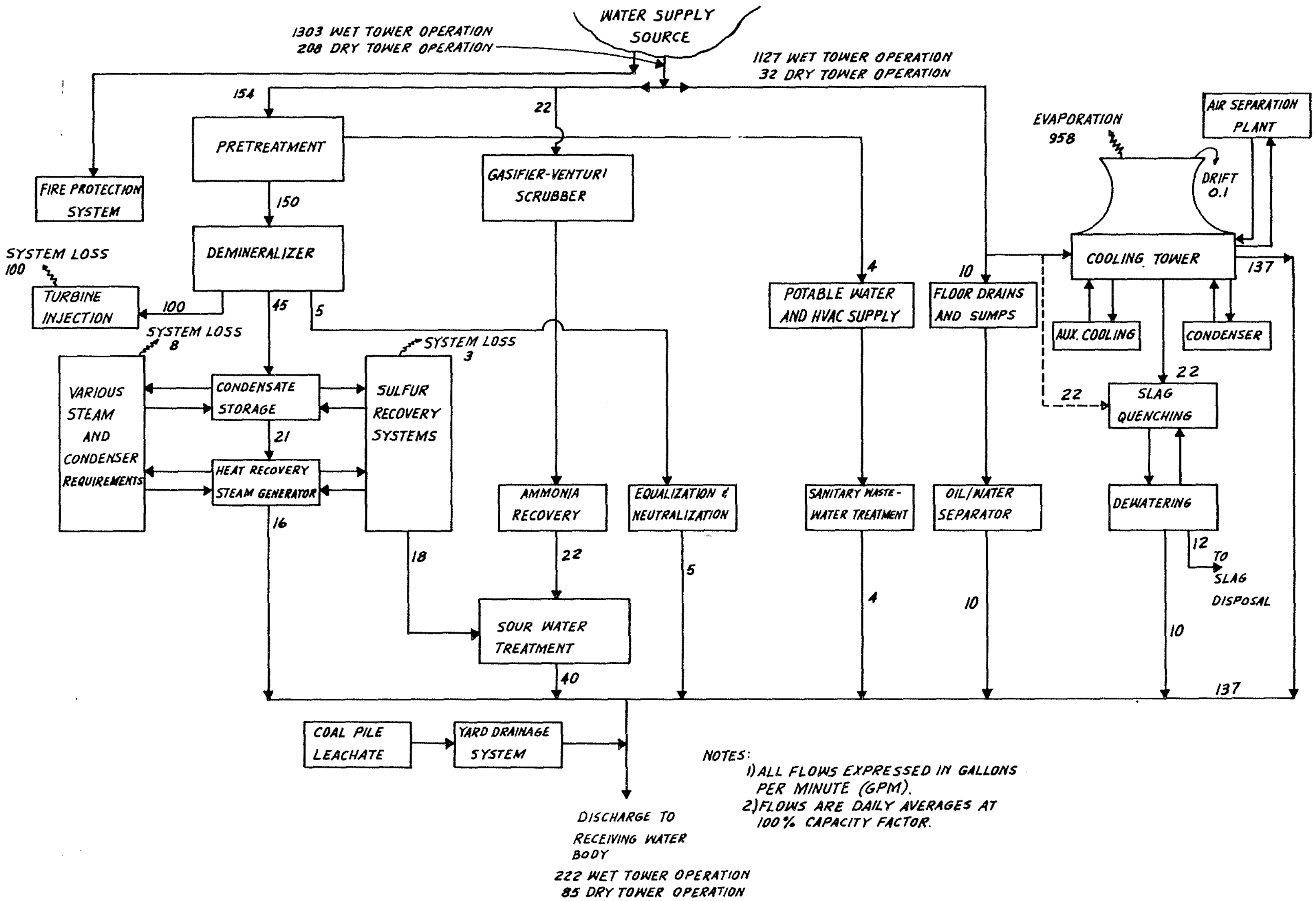



FIGURE 2.7. Water Balance Diagram

requirements. Pretreatment will remove suspended particulate material and residual organics and will consist of gravity filtration and activated carbon filtration. Following pretreatment, steam-cycle makeup and turbine-injection makeup will undergo demineralization for dissolved solids removal. This system will consist of cation exchange, degasification, anion exchange and mixed-bed demineralization. The entire treatment system will consist of three parallel, 50 percent duty trains (one as standby) each producing 75 gallons per minute of demineralized water.

Sanitary Waste Treatment Facility

A prefabricated-type aerobic biological treatment unit will be provided to manage the power plant's sanitary wastes. The package treatment plant will consist of a screening-communitor chamber, an aeration tank, a clarifier and a chlorine contact chamber. Treated effluent will be discharged to the wastewater collection sump. Waste biological solids produced by the plant will undergo aerobic digestion. The system will be sized for a flow of approximately 6000 gallons per day and the aeration tank will provide a retention period of 24 hours.

Floor Drainage Treatment Facility

This facility will provide treatment for the removal of suspended solids and oil/grease and will require both a primary and secondary treatment stage. The primary stage will consist of a gravity oil/water separator that will accomplish both suspended solids and floatable oil removal. The secondary stage will consist of treatment for the removal of emulsified oils, utilizing either cartridge-type separators or chemical coagulation. This prefabricated facility will be designed to handle an average daily flow of 10 gpm. The treated effluent will be discharged to the receiving body.

Equalization/Neutralization Facility

Wastewater from demineralizer regeneration will be produced and conveyed on an intermittent basis to the equalization/neutralization tank having a corrosion-resistant lining. The tank will have a pH monitoring and control system that consists of a pH sensing/control device to automatically add acid or caustic reagents as required to adjust the pH to within a range of 6.0 to

9.0. The tank will have a minimum 36-hour detention period for the wastewater flows generated on the maximum regeneration activity day. This capacity, together with the pH control system, will provide adequate neutralization to enable discharge to the receiving water body.

Coal Pile Runoff Pond Facility

Runoff and filtrate from the coal storage pile will be directed to collection ditches located on the periphery of the pile and then conveyed to the coal pile runoff pond that will be capable of retaining the one-in-ten-year, 24-hour rainfall event and, therefore, only storms in excess of this event will be discharged. The holding pond will provide gravity setting for coal fines (suspended matter) washed out of the pile; this water will then be used for dust-suppression purposes. Pond effluent in excess of the design storm event will undergo pH adjustment, as necessary, to a range of 6.0 to 9.0, by the addition of caustic reagents and will be discharged to the yard and area drainage system.

Yard and Area Drainage System

The yard and drainage system will convey all runoff from the plant site to minimize potential site flooding. This discharge is not considered to be a pollutant source or wastewater requiring treatment, because no contamination of this discharge will occur onsite due to either process or materials storage activities. Therefore, this discharge will be directly discharged to the receiving water body.

Gasifier Water Supply

The gasification section will require water for slag-quenching and product-gas-scrubbing. During evacuation from the lockhopper, the slag will be dewatered and the water recycled to the lower quench section of the gasifier. Makeup water for this system will be supplied from the cooling tower basin during "wet" tower operation and directly from the supply source during "dry" tower operation. A portion of the recycle flow is blowndown to maintain system water quality within desirable limits and to prevent scale accumulation.

Makeup water for the product gas scrubbing system will be derived directly from the supply source. Following gas scrubbing, the effluent from this unit process will be discharged to the ammonia recovery unit where anhydrous ammonia will be produced. Most of the water extracted during the ammonia recovery process will be recycled to the venturi scrubber; a small portion will be blowndown to maintain appropriate water quality levels. This blowdown will be treated in the bio-oxidation system prior to ultimate discharge.

Bio-oxidation Treatment System

This treatment system will consist of an equalization/neutralization basin, a biological and physical/chemical treatment system and a wet-air oxidation system. In general, waste streams from the sulfur recovery units and ammonia recovery system will be treated in this manner prior to discharge. It should be noted, however, that not all waste streams from these process units are necessarily accounted for in the flow diagram or discharged to this treatment unit. Due to the proprietary nature of many of these resource recovery processes, some waste streams will be collected and treated, also by proprietary means, as part of the overall process. For example, a Texaco-developed proprietary process consisting of insoluble metal sulfide precipitation and ammonia stripping is presently utilized to treat tailgas treatment condensate.

The equalization basin for the bio-oxidation system will have the functions of collecting, thoroughly mixing and neutralizing all waste streams destined for biological treatment to provide a constant flow rate and to avoid shock upsets of the system. The basin will be provided with mixer-aerators to insure a homogeneous feed to the biological system. Construction will be of reinforced concrete, because of the nature of the waste streams involved.

The biological treatment unit is based on a conventional activated sludge system to reduce biodegradable organics. However, powdered activated carbon (PAC) will be added directly to the aeration basin for adsorption of nonbiodegradable organics and ammonia as well as cyanides and thiocyanates. The carbon will also help to buffer the system against upsets due to toxic shock and provide surfaces on which the activated sludge biota may grow. Waste sludge disposal and carbon regeneration will be accomplished simultaneously in a wet-air oxidation system.

In the wet-air reactor, adsorbed organics will be oxidized and the adsorptive capacity of the carbon will be restored. Regenerated carbon will be recycled to the aeration tank while some makeup of powdered activated carbon will be necessary due to regeneration losses. During regeneration, the suspended ash associated with the carbon slurry will accumulate at the bottom of the reactor and will be periodically blown down from the unit for disposal to the solid waste disposal area. The effluent from this treatment system will be gravity-filtered through sand, chlorinated and subsequently mixed with the other plant waste streams prior to discharge.

### 2.1.5 Solid Waste Disposal Systems

The facility will produce two major solid byproducts that will require ultimate disposal: ash (slag) and sulfur. A mass balance of these two byproducts is provided in Figure 2.8.

Most of the ash in the coal feed agglomerates into essentially carbon-free molten slag droplets that are quenched and solidified in the lower quench section of the reactor. This slag settles through the quench water into the lockhopper. The lockhopper contents are periodically dumped onto a screen from which the slag is conveyed to an open hopper for temporary storage. Water from the screen is collected in a sump and recycled.

From the hoppers located at the plant site, the slag will be trucked to a permanent solid waste disposal site, assumed to be situated in close proximity to the plant island. To permanently dispose of the slag generated over the 25-year life of the plant, a site encompassing approximately 50 acres at an average depth of 50 feet will be required. It is anticipated that the area will consist of a natural ravine to be ultimately enclosed by an earthen dyke.

Slag formed in the gasification unit will be a generally insoluble glassy material with the consistency of pea gravel. It will contain some larger material up to approximately 1 inch in size and some finer particles. Based on a limited amount of available data, there is no indication that there would be a problem of leaching inorganic salts into the ground or surface streams from a slag disposal site; therefore, a disposal area liner is not specified.

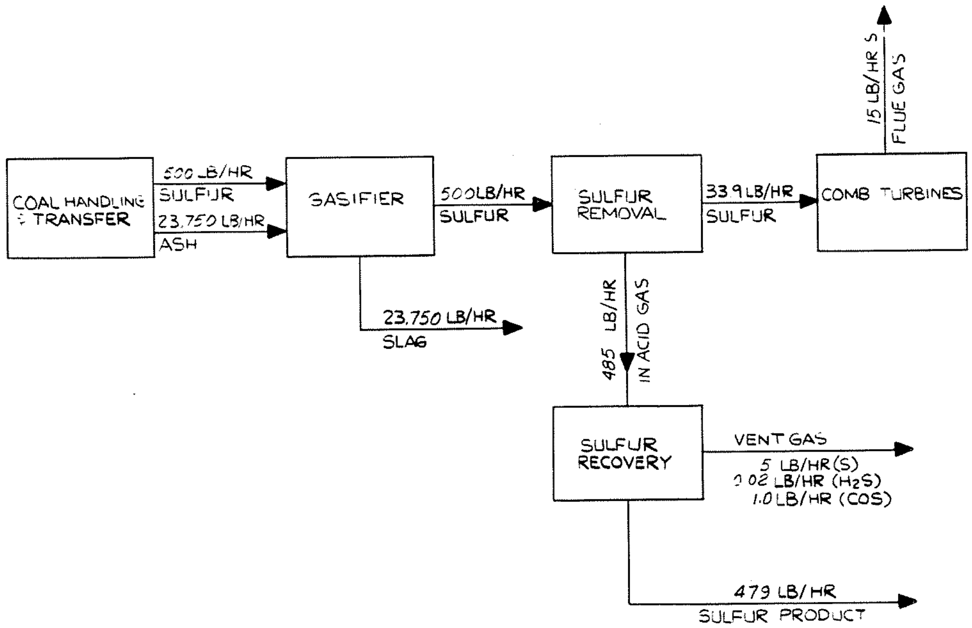



FIGURE 2.8. Sulfur and Ash Balance

The disposal site will also be developed through a series of benches so that areas within the site will reach their final elevation in stages. Once an area has been completed it will be covered with topsoil and reseeded to minimize infiltration and dust related problems. Disposal will start at the shallow end of the site, away from the future dam site, to minimize the amount of exposed slag material.

Lined drainage courses will be provided at the sides of the disposal area to prevent excessive accumulation of water and consequent pile instability. Runoff and seepage from the disposal area will be collected behind a small berm located at the anticipated toe of the slag pile. This water will then be used for dust suppression purposes.

The quantity of sulfur produced as a byproduct of coal gasification will amount to approximately 45,000 tons over the life of the power plant. This is a potentially valuable resource but its sale and reuse will depend on an assessment of local market conditions at the time of project development. Should a market not be found, the effluent from the sulfur recovery units will be dried and trucked to an onsite disposal area. The disposal site will encompass an area of approximately 2 acres, and will be lined with an impermeable material to prevent any leachate from entering the groundwater. The site will also be developed in benches and revegetated to minimize runoff infiltration, and will be surrounded by runoff diversion channels.

## 2.2 FUEL SUPPLY

The proposed station described in this report will use coal from the currently undeveloped Beluga Field. The plant will be essentially mine mouth, with coal deliveries by truck or conveyor.

The surface-mineable Chuitna Lease (used as a reference field for the Beluga region) is located about 12 miles from tidewater on the west side of Cook Inlet. The mine area will also be about 12 miles from the existing Chugach Electric Association Beluga Generation Station.

A recent report by Bechtel Corporation (Bechtel 1980) indicates mineable reserves of 350 million tons, with a stripping ratio of 4:1. Production levels of up to 11,700,000 TPY could be sustained for 30 years without significant depletion of the reserves (Swift 1981).

The Beluga Field could be economically opened with the establishment of an export market. The outlook for development of such a market appears to be excellent, and allowing time for mine design and development and environmental and licensing activities, it appears that Beluga coal could be available as early as 1986 but more certainly by 1988 (Swift 1981).

It is also possible that electric power development of sufficient size could justify opening of the Beluga Field. Current thinking is that an installed coal-fired capacity of approximately 800 MW would allow economic development of this coal.

Run-of-mine quality of Chuitna lease coal is expected to be as follows:[a]

(a) Note that a composite "Railbelt Standard" coal (Section 1.0) was used for plant design.

| | |
|---|---|
| Heating Value | 7500–8200 Btu/lb |
| Ash Content | 7–8% |
| Moisture | 20–28 |
| Hardgrove Grindability Index | 20–25% |
| Ash Softening Temperature | 2350°F |
| Ash $Na_2O$ | 0.95% |
| Sulfur | 0.16–0.18% |
| Nitrogen | N.A. |

## 2.3 TRANSMISSION SYSTEM

Preliminary design calculations were made for a 75-mile, 345-kV transmission line to transmit the 220 MW generated by the coal-gasifier combined-cycle plant from Beluga to Willow. The following assumptions were made for this preliminary estimation:

- This line was considered independent of the existing network.
- The line goes from Beluga to Willow, where the proposed Anchorage-Fairbanks intertie, which has sufficient capacity, will absorb the total generated power.
- The existing system at Willow will be a 345-kV system as recommended by Commonwealth Associates, Inc. (1981).

Three voltage levels were studied: 138 kV, 220 kV and 345 kV. A 138-kV voltage is too low to transmit 220 MW a distance of 75 miles; the surge impedance loading for this line would only be around 50 MW.

A 230-kV voltage line has a surge impedance loading of 135 MW. This type of line with VAR compensation and adequate conductor size could adequately transmit the 220 MW.

A 345-kV voltage line has a surge impedance loading of 300 MW. This type of line with VAR compensation and adequate conductor size could also adequately transmit the 220 MW. A double-circuit 230-kV transmission line may also be an attractive alternative. Initial investment may be higher than the 345 kV alternative, because 230-345 kV transformation at Willow has to be built and transmission towers for a double-circuit 230-kV transmission line may be heavier than the 345-kV towers. However, $I^2R$ losses may be lower. The results obtained from the preliminary study are as follows:

| Line Voltage (kV) | No. of Circuits | Type of Conductor | Size of Conductor (MCM) | Regulation | Losses $I^2R$ MW | Reactive Support |
|---|---|---|---|---|---|---|
| 230 | 1 | ACSR | 636 | 11.9 percent | 14.5 | Capacitors |
| 345 | 1 | ACSR | 795 | 3.5 percent | 4.5 | Reactors |
| 230[a] | 2 | ACSR | 636 | 3.0 percent[a] | 3.8 | None |

(a) Estimated values.

From these preliminary calculations, a 345-kV ACSR, single-circuit, 795 MCM is recommended. However, additional studies will have to be done to fully justify these parameters.

From an electrical point of view, interconnections with the transmission system may substantially modify the results. This line should not be studied independently because capital investment and losses of alternate line configurations will have to be fully evaluated. A complete system study is recommended.

The lowest initial investment will be the single-circuit 230-kV line; however, the losses appear excessive. Differential losses of 10 MW between the 345-kV and 230-kV alternate may result in a loss in revenue of $4,000,000 per year, for a load factor of 80 percent and a cost of 6¢/kWh for energy.

A double-circuit 230-kV line may also be an attractive alternative. Initial investment may be higher than the 345-kV alternative, and transformation from 230 kV to 345 kV at Willow will have to be added. The 345-kV option will have the advantage of uniform voltages with the system recommended by Commonwealth Associates, Inc. (1981) for an Anchorage-Fairbanks intertie.

The physical line arrangements will be as follows: To incorporate the proposed Beluga station output, a 345-kV substation at or near Willow (or some other convenient place) appears desirable and should have a configuration as depicted in Figure 2.9. The 345-kV lines to Anchorage and Beluga and Nenana would terminate here. This substation will provide flexibility and reliability to the system load flow. Connecting the Chugach Beluga station into the system at Willow avoids the underwater crossing at Knik Arm currently in use from the Beluga combustion turbine installation to Anchorage.

## 2.4 SITE SERVICES

The construction and operation of a 220-MW coal-gasifier combined-cycle power plant will require a number of related services to support all work activities at the site. These site services include the following:

- access roads
- construction water supply
- construction transmission lines
- airstrip
- landing facility
- construction camp.

### 2.4.1 Access Roads

Gravel roads with a 9-inch gravel base will be required to connect the plant site with the equipment landing facility in the Beluga area. Good bearing subgrade will be required to support the heavy gasification reactor vessels as they are moved to the site. Where possible, the existing road will be used. Hence, no more than 5 miles of additional road construction is anticipated.

### 2.4.2 Construction Water Supply

A complete water supply, storage and distribution system will be installed. Due to the remote nature of any site developed, a one-million gallon water storage tank has been assumed with one-half of this storage capacity dedicated to fire protection purposes. Construction water supply to the project site should be at least 150 gpm.

### 2.4.3 Construction Transmission Lines

Power requirements during the construction phase will be supplied by constructing a 25-kV transmission line tapped from an existing transmission

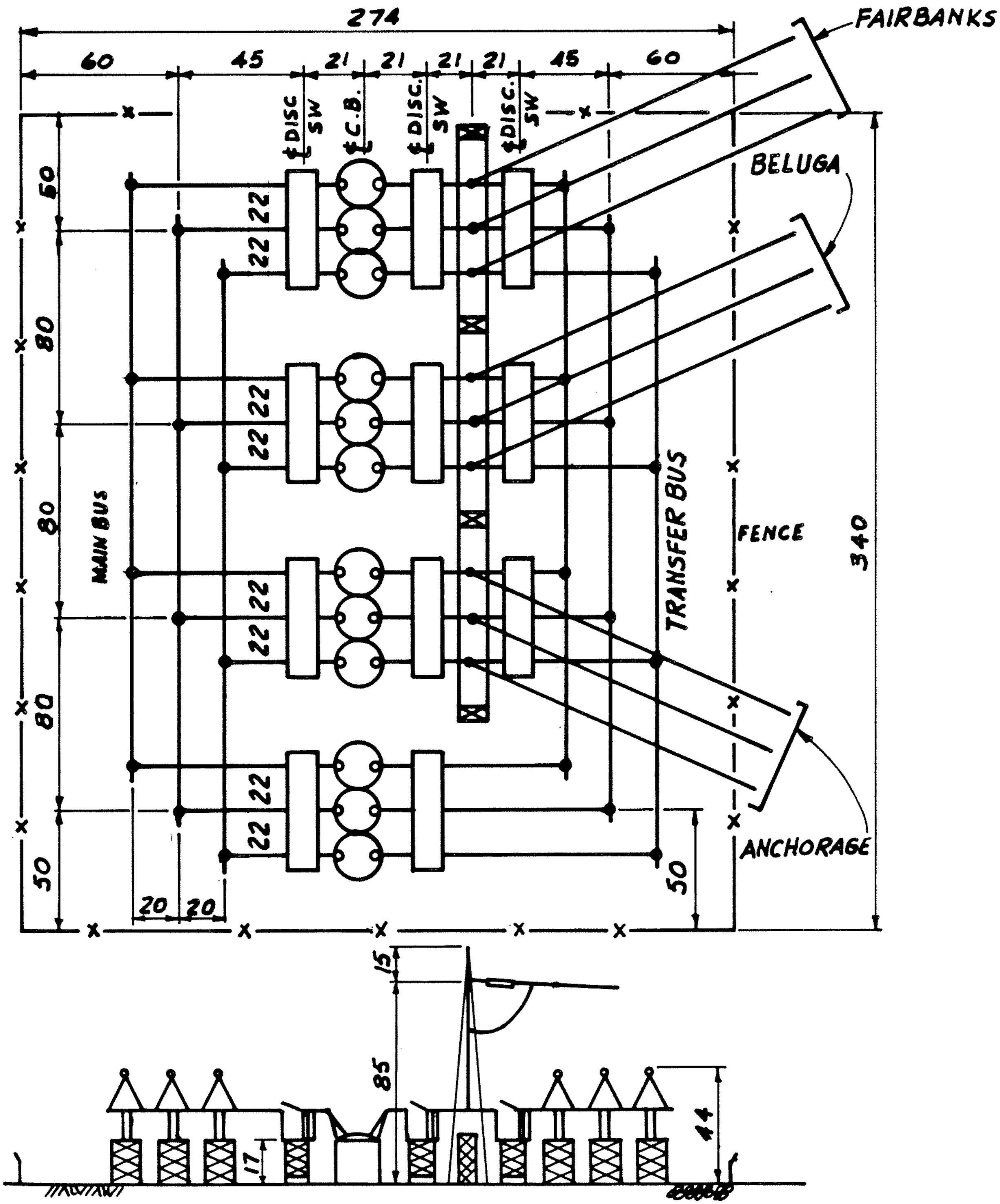



FIGURE 2.9. Willow Substation - 345 kV

system. A transmission line length of 20 miles is assumed and will be derived from the existing Chugach Electric Association system at either the town of Beluga or Tyonek.

### 2.4.4 Airstrip

For the general power plant location, the existing airstrip will be used. It is anticipated that all personnel travel will be by air with prearranged commercial charter carriers. All perishable goods will be flown in. Equipment for construction will be flown in only under extraordinary circumstances. The largest airplane that will be able to land on the strip will be in the 18,000- to 30,000-pound category.

### 2.4.5 Landing Facility

The site will use the existing marine landing facility to receive all construction materials, equipment and supplies. A paved and fenced interim storage area will be provided. A heavy duty haulage road would be provided from the landing area to the access road.

### 2.4.6 Construction Camp Facilities

A 1,000-bed labor camp will be provided. All personnel housed in this camp will be on single status. Provisions will be made to accommodate a work force containing females (separate bathroom and locker facilities).

The camp will have its own well water supply. A sewage treatment facility, waste incinerator and garbage compactor will also be provided. The complex will also have a dining hall and recreation hall.

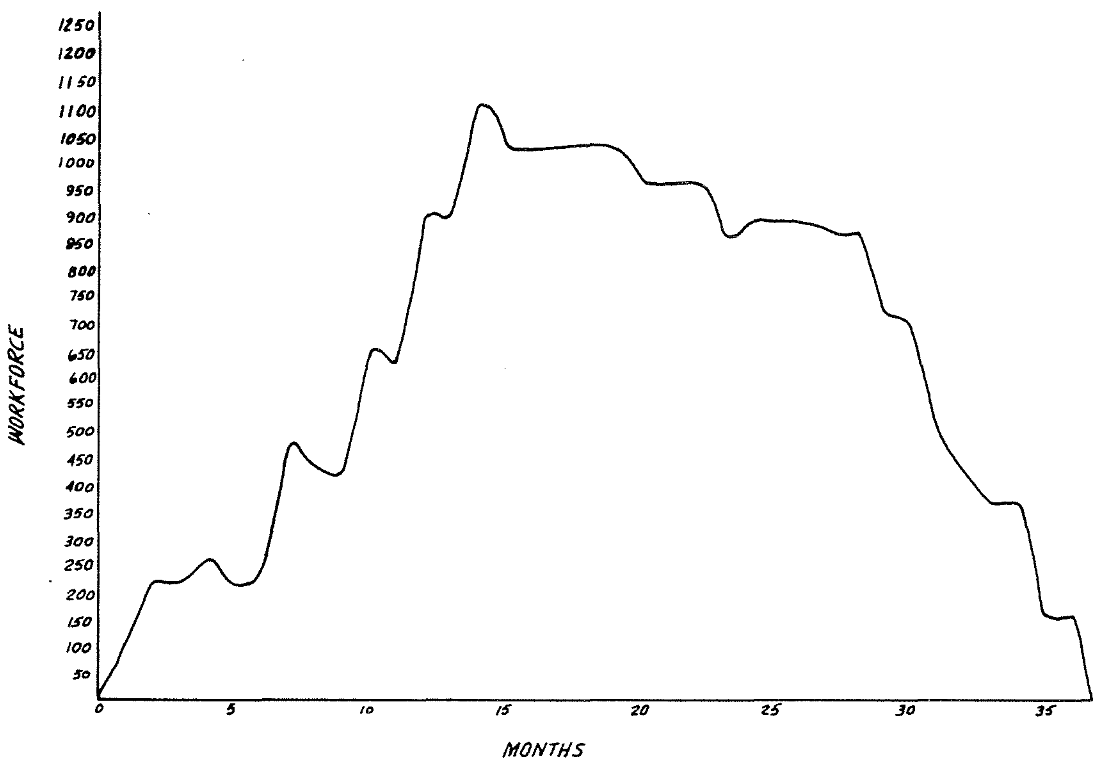
Since it is unlikely that all personnel would be willing to come to the jobsite on single status only, a mobile home park will be provided for 16 supervisory personnel in family status. These mobile homes will be approximately 1,000 $ft^2$ each and could remain after completion of construction to house vendor personnel for repair work during plant operation.

## 2.5 CONSTRUCTION

The number of workers necessary for construction of a 220-MW station will vary over the approximate 3-year construction period. The distribution of this work force over the schedule duration is shown in Figure 2.10. Construction is estimated to peak early in year two, requiring a work force of approximately 1,100 personnel.

Construction of this 220-MW station will follow normal acceptable construction methods. A program of this magnitude begins with orderly development of the following requirements:

1. Construction camp and utility services, such as electric light and power, water for industrial and potable use and fire protection, sanitary facilities, telephone communications, etc.




NOTE: Does not include vendor personnel, owner personnel, A-E engineers, or transmission line construction personnel located at site.

FIGURE 2.10. Construction Work Force Requirements

2. Temporary construction office facilities (with heating and ventilation furnished by contractors as required).
3. Temporary and permanent access roads.
4. Temporary enclosed and open laydown storage facilities.
5. Delivery of various types of construction equipment and vehicles (such as earth-moving equipment, concrete and materials hauling equipment, cranes, rigging equipment, welding equipment, trucks and other vehicles, tools) and other related types of construction equipment by truck, rail, or landing craft or a combination of these, depending on the site.
6. Temporary office and shop spaces for various subcontractors.
7. Settling basins to collect construction area storm runoff.
8. Permanent perimeter fencing and security facilities.
9. Safety and first aid facilities in strict compliance with OSHA regulations.

Following completion of these site preparation activities, power plant systems construction will be initiated. The activities involved in the overall construction process as well as the plant's detailed development schedule are presented in Figure 2.11.

## 2.6 OPERATION AND MAINTENANCE

### 2.6.1 General Operating Procedures

The plant has been designed for operation as a base-loaded plant with load following capability; however, it could be operated as a peaking unit with the excess product gas from the gasifiers being converted to methanol during off peak hours. (The methanol conversion plant has not been included in this report, however.) Cold starts of the combined-cycle plant should be expected to take a minimum of 9 hours. The first gas turbine is started and synchronized with the bypass damper positioned to partially bypass the steam generator. The second steam generator is started and synchronized in

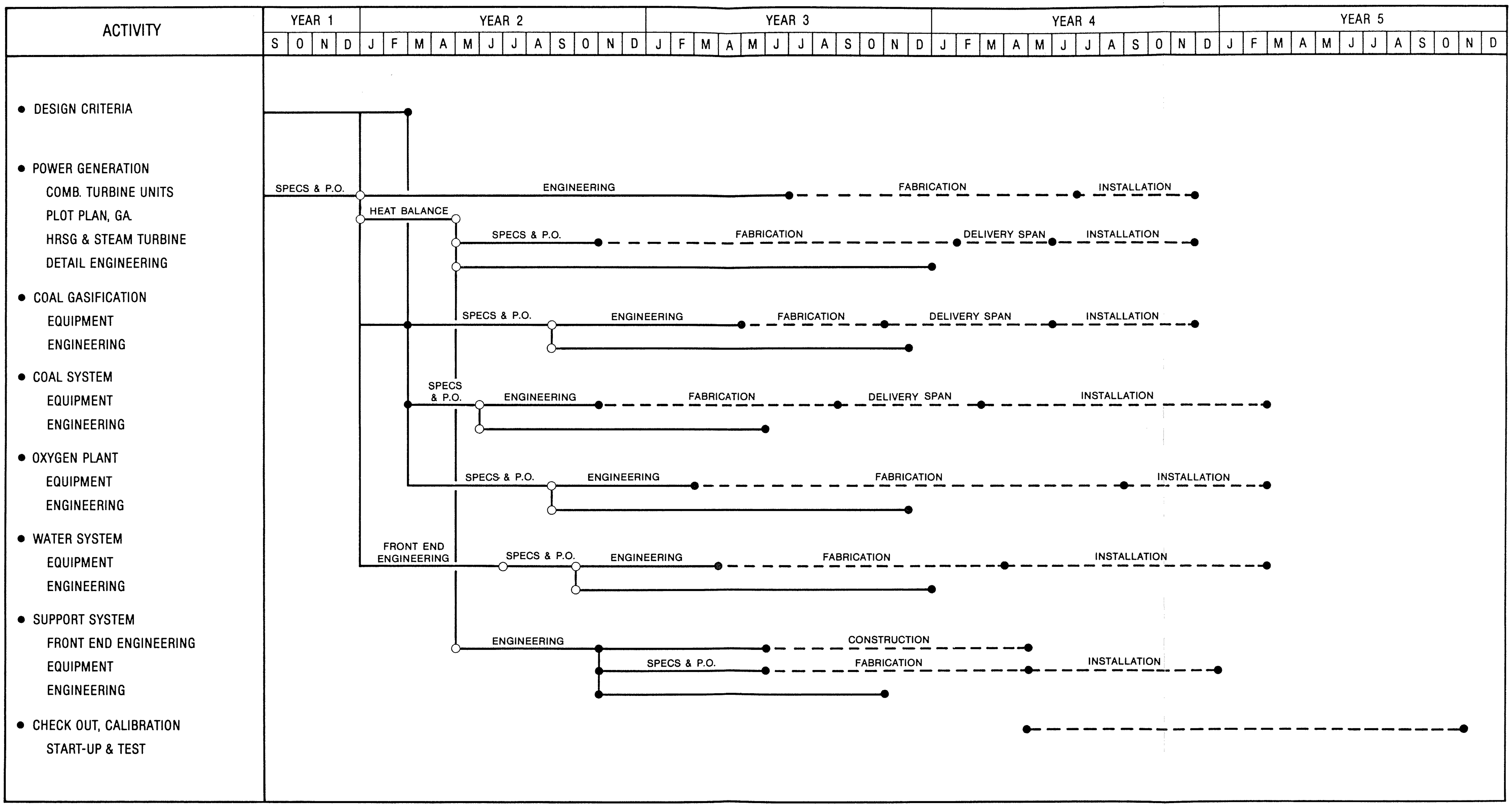



FIGURE 2.11. Construction Schedule

similar manner. A vacuum is pulled in the condenser, using the vacuum pumps and the steam turbine warmed over the course of several hours, in accordance with manufacturers' instructions. The bypass dampers can be repositioned as required during the start-up period to control steam flow, and opened fully when the steam turbine is loaded.

The plant cold start is based on using distillate oil from the emergency fuel tanks on one of the gas turbines. A diesel generator started on compressed air will provide the power for starting the gas turbine.

Once the gas turbine is producing power, the gasifier train can be started and operation on distillate oil continued until the gasifier produces sufficient quantities of fuel gas.

Hot starts are accomplished by starting and synchronizing the first gas turbine using distillate oil. The heat recovery steam generator is then loaded and the steam turbine started. After the steam turbine is up to speed, the second gas turbine is started, the second steam generator is loaded and the plant is brought up to load. At this time the oxygen plant is started and brought up to load. The gasifier is started with a mixture of oil and coal. When it has reached operating temperature, the oil is shut off and operations are sustained on coal while the first gas turbine is switched to MBG. When the system is stabilized, the other turbine is switched to MBG and full load assumed.

### 2.6.2 Operating Parameters

Operating experience on coal-gasifier combined-cycle plants is somewhat limited when compared to coal- or oil-fired power plants. Therefore, conclusions on operating parameters are based on the available data on gas-fired combined-cycle plants supplemented by EPRI (1978) data and known experience on gas turbines and steam turbines.

The forced outage rate can be expected to be about 8 percent. Initial operation experience on some earlier plants indicates higher forced outages in the first few years, but this is attributed to problems associated with starting up a new-type plant, and development of the current gas turbine design. We would expect to see a slight increase in forced outages as the plant ages, but do not anticipate the "technology development"-type outages experienced by some of the earlier plants. Variations in plant sizes should not affect the forced outage rate provided that the same "experience factor" is involved with the gas turbines used.

Cycling the plant will have a negative effect on all the plant machinery, due to the numerous system stress reversals encountered with this type operation, and a higher forced outage rate should be anticipated if the plant is run as a peaking unit.

The coal-gasification combined-cycle plant reliability is very dependent on an adequate preventative maintenance program, and scheduled outrage rates can be expected to be about 7 percent. Again, plant size will not affect the scheduled outage rate, but cycling service will necessitate more frequent inspections, which will result in a higher scheduled outage rate. An equivalent plant availability of approximately 86 percent should be obtained with the forced and scheduled outage rates of 8 percent and 7 percent, respectively.

The plant heat rate of approximately 9,287 Btu/kWh is not expected to vary significantly with plant size within the range of 100 MW to 400 MW, but should rise slightly as the plant ages. The heat rate will, however, vary considerably with plant loading, as the efficiency of the gas turbines deteriorates rapidly as the load is reduced. At extremely low load conditions, in the 20 to 30 MW range, heat rates as high as 14,000 to 16,000 Btu/kWh should be anticipated. For a combined-cycle plant in load following service, consideration should be given to using a larger steam turbine and varying the steam turbine output with supplementary duct burner firing. Duct burner firing would raise the heat rate, but offers a distinct advantage in heat rate over gas turbine cycling for the variable load plant.

### 2.6.3 Plant Life

Based on the life of the gas turbine units, the plant should have a 25-year life expectancy. It is expected that the gas turbine units and gasifier components will be partially rebuilt a number of times during the scheduled (and unscheduled) outages.

### 2.6.4 Operating Work Force

The plant will require an operating staff of approximately 110 employees. Of this total, approximately 71 represent operating staff while 39 are maintenance personnel. An estimate of the plant's staffing requirements is presented in Table 2.12. Employment of these personnel will continue throughout the life of the plant.

Plant systems will be operated from the control room located in the main plant building. Some of the systems and equipment will also be controlled from local stations. In general, controls are automatic, although operators can override the automatic controls and operate the plant manually. To supplement the operational controls, the station will be equipped with an alarm system, fire protection system, proper lighting, and a radiotelephone communication system.

### 2.6.5 General Maintenance Requirements

Periodic maintenance will be performed on all pressure systems, rotating machinery, heat sensitive equipment, and other operating equipment to prevent malfunctions, leaks, corrosion and other such abnormalities. The periodic maintenance should be performed in accordance with an established maintenance program. This would include the complete strip down and major inspection of the turbines as required or suggested by the equipment manufacturer. Periodic replacement of refractory linings in the gasifier components will also be accomplished every 2 or 3 years during scheduled maintenance shutdowns. Other system elements, such as the gas cleanup train and air separation plant, which are commercial units, will require minimal maintenance during the periodic inspections. In addition, the maintenance programs will monitor the revegetation and erosion prevention programs of the plant site initiated during the cleanup phase of construction. Trained maintenance crews will perform operational maintenance and will correct emergency malfunctions. In general, all major maintenance functions will be performed during the plant's scheduled outages.

TABLE 2.12. Plant Staffing Requirements

| Job Title | Power[(a)] Plant | Gasifier[(a)] Plant | Coal[(b)] Yard |
|---|---|---|---|
| Plant Superintendent | 1 | -- | |
| Operations Engineer | 1 | 4 | |
| Shift Superintendent | 4 | 4 | |
| Control Room Operators and Auxiliary Operators | 4 | 8 | |
| Chemist | 1 | 1 | |
| Chemical Technician | | 4 | |
| Results Engineer | 1 | 1 | |
| Results Technician | 1 | 1 | |
| Instrument and Controls Engineer | 1 | 1 | |
| Instrument and Controls Technician | 4 | 4 | |
| Storekeeper | 1 | | |
| Clerical | 2 | 1 | |
| Maintenance Superintendent | 1 | 1 | |
| Maintenance Engineer | 1 | 1 | |
| Maintenance Foreman (Electrical/Mechanical) | 2 | 1 | |
| Mechanics (6-Man Crews) | 6 | 4 | |
| Maintenance Foreman (Instrument and Controls) | 1 | 1 | |
| Mechanics (2-Man Crews) | 2 | 4 | |
| Labor Foreman | 1 | 1 | |
| Labor Crew | 4 | 4 | |
| Fire Protection/Security Staff | 4 | 0 | |
| Coal Yard Foreman | | | 3 |
| Tractor Operator | | | 7 |
| Breaker House Operator | | | 3 |
| Ash Plant Operator | | | 4 |
| Disposal Site Operators | | | 3 |
| Maintenance Mechanic | | | 1 |
| Total | 43 | 46 | 21 |

Plant Total: 110

(a) Three 8-hour shifts and seven-days-a-week operation.
(b) Two 8-hour shifts, seven-days-a-week operation.

## 3.0 COST ESTIMATES

### 3.1 CAPITAL COSTS

#### 3.1.1 Construction Costs

Construction costs in January 1982 dollars have been developed for the major bid line items common to a coal-gasifier combined-cycle power plant. These lines items costs have been broken down into the following categories: labor and insurance, construction supplies, equipment operation costs, equipment rental, and permanent materials. Results of this analysis are presented in Table 3.1. The equivalent unit capital cost of the plant is 3284 $/kW.

#### 3.1.2 Payout Schedule

A payout schedule has been developed for the entire project and is presented in Table 3.2. The payout schedule was based on a 36-month basis from start of construction to project completion.

#### 3.1.3 Capital Cost Escalation

Estimates of real escalation in capital costs for the plant are presented below. These estimates were developed from projected total escalation rates (including inflation) and subtracting a Gross National Product deflator series which is a measure of inflation.

| Year | Materials and Equipment (Percent) | Construction Labor (Percent) |
|---|---|---|
| 1981 | 1.0 | 0.5 |
| 1982 | 1.2 | 1.7 |
| 1983 | 1.2 | 1.7 |
| 1984 | 0.7 | 1.3 |
| 1985 | -0- | -0- |
| 1986 | -0.1 | -0.1 |
| 1987 | 0.3 | 0.3 |
| 1988 | 0.8 | 0.8 |
| 1989 | 1.0 | 1.0 |
| 1990 | 1.1 | 1.1 |
| 1991 | 1.6 | 1.6 |
| 1992 - on | 2.0 | 2.0 |

TABLE 3.1. Bid Line Item Costs for Beluga Area Coal-Gasifier Combined-Cycle Project[(a)] (January 1982 Dollars)

| Bid Line Item | Construction Labor and Insurance | Construction Supplies | Equipment Repair Labor | Equipment Rent | Permanent Materials | Total Direct Cost |
|---|---|---|---|---|---|---|
| 1. Improvements to Site | 370,300 | | 425,000 | 324,400 | 13,800 | 1,133,500 |
| 2. Earthwork and Piling | 956,800 | 121,500 | 296,200 | 479,900 | 8,662,500 | 10,516,900 |
| 3. Circulating Water System | 5,021,500 | 690,000 | 44,900 | 69,800 | 7,740,000 | 13,566,200 |
| 4. Concrete | 9,521,200 | 914,500 | 1,025,600 | 623,300 | 4,156,500 | 16,241,100 |
| 5. Structural Steel and Lift Equipment | 2,135,100 | 805,000 | | 1,050,000 | 12,035,000 | 16,025,100 |
| 6. Buildings | 1,223,600 | 147,200 | | 256,000 | 2,610,700 | 4,237,500 |
| 7. Turbine Generator | 5,716,900 | 172,500 | | 275,000 | 33,200,000 | 39,364,400 |
| 8. Steam Generator and Accessories | 3,995,100 | 115,000 | | 220,000 | 11,000,000 | 15,330,100 |
| 9. Coal Gasification Plant | 10,120,800 | 920,000 | | 1,500,000 | 36,100,000 | 48,640,800 |
| 10. Air Quality Control System | 6,343,200 | 575,000 | | 200,000 | 21,740,000 | 28,858,200 |
| 11. Air Separation Plant | 5,250,200 | 230,000 | | 800,000 | 31,000,000 | 37,280,200 |
| 12. Other Mechanical Equipment | 11,128,100 | 345,000 | | 165,000 | 25,642,000 | 37,280,100 |
| 13. Coal and Ash Handling | 2,934,200 | 920,000 | | 400,000 | 9,800,000 | 14,054,200 |
| 14. Piping | 15,960,500 | 1,035,000 | | 360,000 | 22,000,000 | 39,355,500 |
| 15. Insulation and Lagging | 632,600 | 201,300 | | 150,000 | 3,500,000 | 4,483,900 |
| 16. Instrumentation | 1,613,000 | 138,000 | | 40,000 | 12,550,000 | 14,341,000 |
| 17. Electrical Equipment | 12,651,000 | 172,500 | | 75,000 | 28,200,000 | 41,098,500 |
| 18. Painting | 3,162,800 | 115,000 | | 75,000 | 2,000,000 | 5,352,800 |
| 19. Off-Site Facilities | 2,451,400 | 211,100 | 3,621,100 | 2,693,600 | 979,200 | 9,956,700 |
| 20. Waterfront Construction | 28,700 | | 63,500 | 47,300 | 350,000 | 489,500 |
| 21. Substation | 1,043,700 | 23,000 | | 11,000 | 4,035,500 | 5,113,200 |
| 22. Construction Camp Expenses | 8,628,500 | 28,787,800 | | | | 37,416,300 |
| 23. Indirect Construction Costs and Architect/Engineer Services[(b)] | 19,159,700 | 89,590,900 | 2,123,900 | 2,818,800 | | 113,693,300 |
| SUBTOTAL | 130,048,900 | 126,230,330 | 7,600,200 | 12,634,100 | 277,315,200 | 553,828,700 |
| Contractor's Overhead and Profit | | | | | | 72,300,000 |
| Contingencies | | | | | | 96,400,000 |
| TOTAL PROJECT COST | | | | | | 722,528,700 |

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.
(b) Includes $72,300,000 for engineering services and $41,393,300 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

TABLE 3.2. Payout Schedule for Beluga Area Coal-Gasifier Combined-Cycle Project

| Month | Cost per Month (Dollars) | Cumulative Cost (Dollars) |
|---|---|---|
| 1 | 8,403,500 | 8,403,500 |
| 2 | 10,324,100 | 18,727,600 |
| 3 | 10,324,100 | 29,051,700 |
| 4 | 12,952,100 | 42,003,800 |
| 5 | 12,583,000 | 54,586,800 |
| 6 | 12,583,000 | 67,169,800 |
| 7 | 14,904,900 | 82,074,700 |
| 8 | 12,342,300 | 94,417,000 |
| 9 | 11,898,600 | 106,315,600 |
| 10 | 19,078,700 | 125,394,300 |
| 11 | 18,756,500 | 144,150,800 |
| 12 | 23,049,200 | 167,200,000 |
| 13 | 23,049,200 | 190,249,200 |
| 14 | 28,990,600 | 219,239,800 |
| 15 | 29,404,600 | 248,644,400 |
| 16 | 29,404,600 | 278,049,000 |
| 17 | 29,404,600 | 307,453,600 |
| 18 | 29,404,600 | 336,858,200 |
| 19 | 29,404,600 | 366,262,800 |
| 20 | 27,191,500 | 393,454,300 |
| 21 | 27,191,500 | 420,645,800 |
| 22 | 27,191,500 | 447,837,300 |
| 23 | 25,653,000 | 473,490,300 |
| 24 | 25,467,300 | 498,957,600 |
| 25 | 25,467,300 | 524,424,900 |
| 26 | 25,467,300 | 549,892,200 |
| 27 | 24,750,300 | 574,642,500 |
| 28 | 24,750,300 | 599,392,800 |
| 29 | 22,560,500 | 621,953,300 |
| 30 | 21,673,300 | 643,626,600 |
| 31 | 16,621,700 | 660,248,300 |
| 32 | 15,988,400 | 676,236,700 |
| 33 | 13,950,700 | 690,187,400 |
| 34 | 13,950,700 | 704,138,100 |
| 35 | 9,195,400 | 713,333,500 |
| 36 | 9,195,200 | 722,528,700 |

### 3.1.4 Economics of Scale

At present, coal gasifiers have a limited maximum unit capacity of about 1,000 tons/day. Therefore, increasing a facility's power output can only be achieved by the addition of gasifier modules. As a result, significant economies of scale would not be realized by increasing plant size.

Developmental research is proceeding in this area, however, and Shell Koppers unit capacities of approximately 2300 tons/day are planned for about 1990. In the future, then, economies of scale could be realized for many site development costs, including temporary facilities, construction equipment and construction labor. These savings would be brought about by increasing facility capacity through an increase in component capacity. For example, in the range of considered plant sizes (up to approximately 300 MW) utilization of larger-unit-capacity gasifiers, 100-MW combustion turbines, and larger heat recovery boilers would necessitate only a slight increase in the construction work force over that required for smaller unit sizes. In addition, the plant could be constructed within the same time frame as a smaller plant, resulting in a reduction of unit cost on a per megawatt basis.

### 3.1.5 Working Capital

Working capital costs, including a 54-day emergency coal supply, 179,000 bbl of No. 2 fuel oil, and 30-day O&M costs, are estimated to be $65.30. The cost of the emergency coal supply is based on a forecasted 1991 price of $1.80/MMBtu delivered coal to the plant site. The price of No. 2 distillate is estimated to be $8.23 MMBtu in 1991.

## 3.2 OPERATION AND MAINTENANCE COSTS

### 3.2.1 Operation and Maintenance Costs

The operation and maintenance costs for the 200-MW size plant, expressed in January 1982 dollars, are as follows:

Fixed Costs

| | |
|---|---|
| Staff (110 Persons) | $3,711,000 (16.87 $/kW/yr) |

Variable Costs

| | |
|---|---|
| Operating Supplies and Expenses | $460,000 (0.27 mills/kWh) |
| Maintenance Supplies and Expenses | $694,000 (0.4 mills/kWh) |

### 3.2.2 Escalation

Estimated real escalation of fixed and variable operation and maintenance costs are as follows:

| Year | Escalation (Percent) |
|---|---|
| 1981 | 1.5 |
| 1982 | 1.5 |
| 1983 | 1.6 |
| 1984 | 1.6 |
| 1985 | 1.7 |
| 1986 | 1.8 |
| 1987 | 1.8 |
| 1988 | 2.0 |
| 1989 | 2.0 |
| 1990 | 2.0 |
| 1991 | 2.0 |

### 3.2.3 Economics of Scale

Costs associated with personnel salaries are generally the major component of operation and maintenance costs for energy generating facilities. In light of this fact economies of scale would result from larger unit capacities because the personnel requirements are more a function of items or equipment and, therefore, would not increase in direct proportion to additional capacity. These savings are only achievable if the facility is planned for operation in the mid-1990s, because increased gasifier unit capacities will not be available until this time.

## 3.3 FUEL AND FUEL TRANSPORTATION COSTS

Estimated prices for Beluga coal are developed in another report in this series (Swift 1981). Coal for the proposed Beluga Station would be supplied from the currently undeveloped Beluga Field by truck and conveyor. Future prices were calculated by estimating a weighted average delivered price of four competing Pacific Rim coals at Japan. Alaska-Japan transportation costs were backed out resulting in a net back mine-mouth price. Real escalation was based on the composite effect of estimated supply functions for each competing Pacific Rim coal. The resulting mine-mouth price stream is shown in Table 3.3. This analysis, of course, presumes development of an export Pacific Rim market

## 3.4 COST OF ENERGY

Estimated busbar energy cost from the proposed Beluga Station is 63 mills/kWh. This is a levelized lifetime cost, in January 1982 dollars, assuming a 1991 first year of commercial operation and an 85 percent capacity factor. Estimated busbar energy costs for other capacity factors and other startup dates are shown in Figure 3.1. Year-of-occurrence energy costs and capital, O&M and fuel component costs for a plant coming on line in 1991 are shown in Table 3.4. Year-of-occurrence costs are sensitive to escalating fuel costs.

These costs are based on the following financial parameters:

| | |
|---|---|
| Debt Financing | 100% |
| Equity Financing | 0% |
| Interest on Debt | 3% |
| Federal Taxes | 0% |
| State Taxes | 0% |
| Bond Life | 25 years |
| General Inflation | 0% |

The escalation factors given in Sections 3.1 and 3.2 were employed. Weighted average capital cost escalation factors were derived using a labor/material ratio of 25 percent/75 percent.

TABLE 3.3. Estimated Coal Prices: Beluga Station (January 1982 dollars) (Swift 1981)

| Year | Beluga Coal Mine Mouth[(a)] ($/MMBtu) |
|---|---|
| 1980 | -- |
| 1981 | -- |
| 1982 | -- |
| 1983 | -- |
| 1984 | -- |
| 1985 | -- |
| 1986 | -- |
| 1987 | -- |
| 1988 | 1.69 |
| 1989 | 1.72 |
| 1990 | 1.76 |
| 1991 | 1.80 |
| 1992 | 1.83 |
| 1993 | 1.87 |
| 1994 | 1.91 |
| 1995 | 1.95 |
| 1996 | 1.99 |
| 1997 | 2.03 |
| 1998 | 2.08 |
| 1999 | 2.12 |
| 2000 | 2.16 |
| 2001 | 2.21 |
| 2002 | 2.26 |
| 2003 | 2.30 |
| 2004 | 2.35 |
| 2005 | 2.40 |
| 2006 | 2.45 |
| 2007 | 2.50 |
| 2008 | 2.55 |
| 2009 | 2.61 |
| 2010 | 2.66 |

(a) 2.1 percent annual escalation rate from 1980 base price.

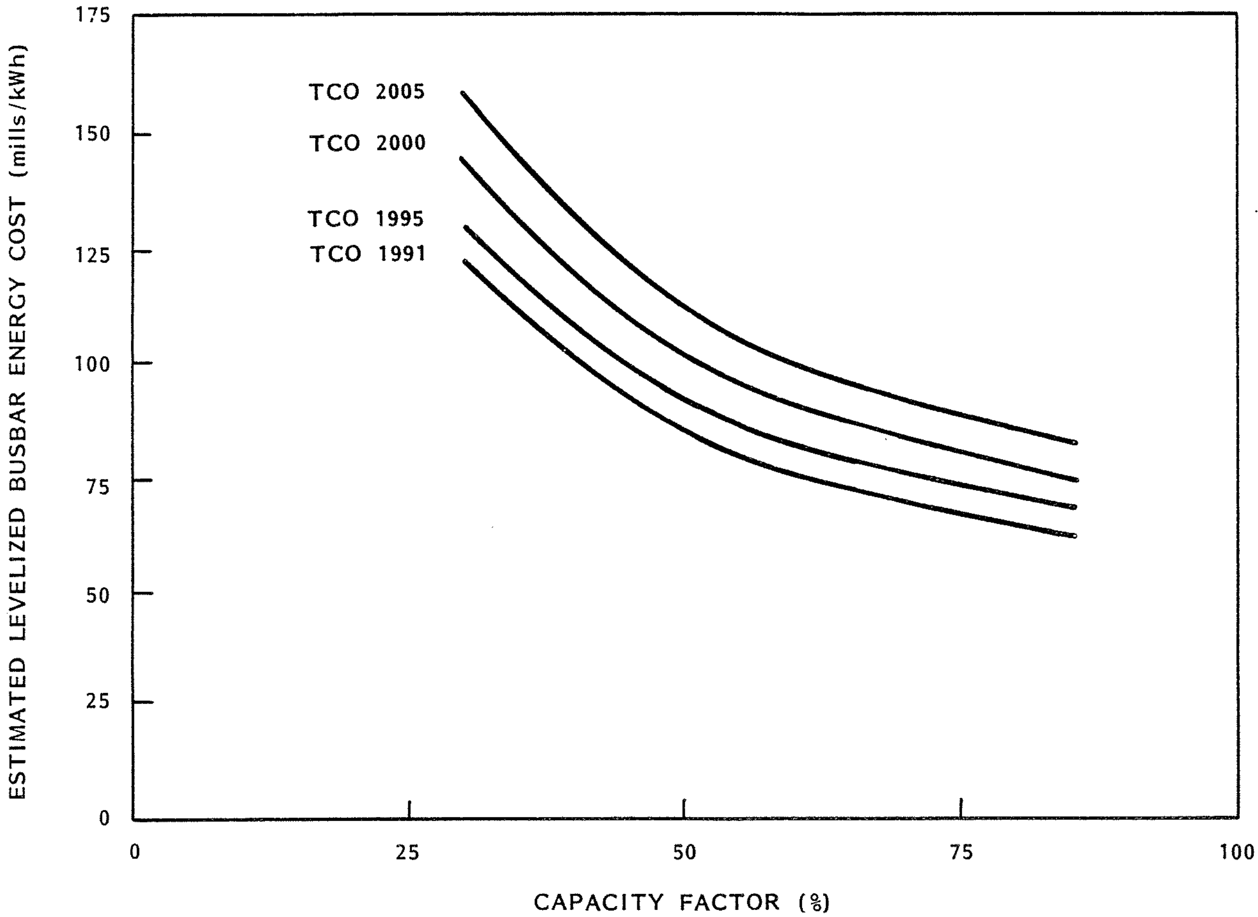



FIGURE 3.1. Cost of Energy Versus Capacity Factor and Year of First Commercial Operation (TCO) (January 1982 dollars)

TABLE 3.4. Year-of-Occurrence Energy Costs (1991 First Year of Operation; January 1982 dollars)

| Year | Unit Capital Costs (mills/kWh) | Unit O&M Costs (mills/kWh) | Unit Fuel Costs (mills/kWh) | Total Unit Costs (mills/kWh) |
|---|---|---|---|---|
| 1991 | 28.9 | 10.9 | 16.7 | 56.5 |
| 1992 | 28.9 | 11.1 | 17.0 | 57.0 |
| 1993 | 28.9 | 11.3 | 17.4 | 57.6 |
| 1994 | 28.9 | 11.5 | 17.7 | 58.2 |
| 1995 | 28.9 | 11.8 | 18.1 | 58.8 |
| 1996 | 28.9 | 12.0 | 18.5 | 59.4 |
| 1997 | 28.9 | 12.3 | 18.9 | 60.0 |
| 1998 | 28.9 | 12.5 | 19.3 | 60.7 |
| 1999 | 28.9 | 12.7 | 19.7 | 61.4 |
| 2000 | 28.9 | 13.0 | 20.1 | 62.0 |
| 2001 | 28.9 | 13.3 | 20.5 | 62.7 |
| 2002 | 28.9 | 13.5 | 21.0 | 63.4 |
| 2003 | 28.9 | 13.8 | 21.4 | 64.1 |
| 2004 | 28.9 | 14.1 | 21.8 | 64.8 |
| 2005 | 28.9 | 14.4 | 22.3 | 65.6 |
| 2006 | 28.9 | 14.6 | 22.8 | 66.3 |
| 2007 | 28.9 | 14.9 | 23.2 | 67.1 |
| 2008 | 28.9 | 15.2 | 23.7 | 67.8 |
| 2009 | 28.9 | 15.5 | 24.2 | 68.7 |
| 2010 | 28.9 | 15.9 | 24.7 | 69.5 |
| 2011 | 28.9 | 16.2 | 25.3 | 70.4 |
| 2012 | 28.9 | 16.5 | 25.7 | 71.1 |
| 2013 | 28.9 | 16.8 | 26.3 | 72.0 |
| 2014 | 28.9 | 17.2 | 26.8 | 72.9 |
| 2015 | 28.9 | 17.5 | 27.4 | 73.8 |

# 4.0 ENVIRONMENTAL AND ENGINEERING SITING CONSTRAINTS

This section presents many of the constraints that would be evaluated during a siting study. Special attention is given to the applicability of these constraints to the Beluga area. The purpose of such a study is to identify a preferred location(s) and possibly viable alternative locations for the construction and operation of the generating station. Through this process, environmental and engineering constraints are minimized, which subsequently minimizes project costs.

Many of the constraints placed upon the development of a coal-gasifier combined-cycle power plant are regulatory in nature; therefore, the discussion presented in this section is complemented by the identification of power plant licensing requirements presented in Section 6.

## 4.1 ENVIRONMENTAL SITING CONSTRAINTS

Potential environmental siting constraints include effects on water resources, air resources, aquatic and marine ecology, terrestrial ecology, and socioeconomic considerations.

### 4.1.1 Water Resources

Water resource siting constraints generally center about two topics: water availability and water quality. The power plant requires a reliable source of water for its efficient operation. It is generally attempted to minimize flow reduction of potential water supply sources while maximizing reliability. For this reason, it is necessary to examine low flows as well as average yearly and monthly flows for potential water sources. Special consideration will have to be given to intake structure location and design to avoid freezing and ice-related problems. Consideration of stream morphology and geometry will also be important to avoid local flow reduction effects in the vicinity of the structure(s) during low flow periods. Alternative sources of water must be sought. Potential sources include small stream systems, groundwater and sea water. Sea water is suitable for cooling purposes only. Groundwater sources exist in this area, with well yields estimated to be as high as 1000 gpm near the larger surface water bodies. Yields, however, generally range from 10 gpm to 100 gpm away from surface water bodies. Another alternative could include groundwater for process use and salt water for cooling purposes. The use of groundwater or sea water could, however, significantly increase power plant costs. This cost increase would have to be evaluated in light of the potential impact of utilizing surface water resources.

Water quality can represent a significant siting criterion, in that receiving stream water quality standards could prohibit plant effluent discharge. Poor makeup water quality can impact water management requirements by requiring either an extensive water treatment facility prior to plant use, as could be the case if groundwater were used, or by limiting plant recycle, thus requiring a costly internal treatment/recycle facility.

### 4.1.2 Air Resources

The air resources siting process involves the determination of those areas within the overall study location where power plant siting would appear feasible from a regulatory point of view. A full discussion of the air-related regulatory requirements appears in Section 6; however, the major factors that must be evaluated include:

- proximity to areas designated Class I under Prevention of Significant Deterioration (PSD) regulations
- proximity to non-attainment areas for ambient air quality standards
- general dispersion capability of the area.

These factors are evaluated through the use of computerized mathematical models that develop estimates of atmospheric diffusion and, subsequently, the concentration of various air pollutants. Input to the model consists of the characteristic emissions from the plant and local meteorological data.

Of the three factors listed above, the location of the Class I area at Tuxedni Bay could pose the most severe siting constraint for development of a coal gasifier/combined-cycle facility in the Beluga region. The allowable increments of air quality deterioration are extremely small in Class I areas. A minimum distance from this area would probably be at least 20 miles, but each potential site must be analyzed in detail. The Class I visibility regulations could significantly affect this minimum distance.

### 4.1.3 Aquatic and Marine Ecology

Plant makeup water and discharge requirements may be large when compared to the surface water resources of the Beluga area. Therefore, it is possible that wastewater discharge may impact site selection. Baseline data would need to be developed, and an identification of exclusion and avoidance areas made, to be considered in association with intake and discharge structure development. Exclusion and avoidance areas would primarily be based upon an inventory of fish spawning habitat and upstream migration pathways, fish nursery habitat and downstream migration pathways, important benthic habitat, rare and/or endangered species and their critical habitats, and an assessment of potential entrainment and impingement impacts.

### 4.1.4 Terrestrial Ecology

Since habitat loss is generally considered to represent the most significant impact on wildlife, an identification of important wildlife areas, especially critical habitat of threatened or endangered species, would be required. Based upon this inventory, exclusion, avoidance and preference areas would be delineated and factored into the overall plant siting process.

A number of important and sensitive species inhabit the Beluga area. These include moose and black bear; small fur bearers, such as lynx, beaver and muskrat; and various bird species, including bald eagles and colonial nesting birds, such as seagulls, puffins and cormorants. Appropriate consideration of these species and their habitats will be required during the plant siting process.

### 4.1.5 Socioeconomic Constraints

Major socioeconomic constraints center about potential land use conflicts and community and regional socioeconomic impacts of project development. Potential exclusionary land uses will consist of those areas that contain lands set aside for public purposes, areas protected and preserved by legislation (federal, state or local laws), areas related to national defense, areas in which a coal-gasifier combined-cycle installation might preclude or not be compatible with local activities (e.g., urban areas or Indian reservations), or areas presenting safety considerations (e.g., aircraft facilities). Avoidance areas will generally include areas of proven archaeological or historical importance not under legislative protection, and prime agricultural areas.

Minimization of the boom/bust cycle will be a prime concern. Through the application of criteria pertaining to community housing, population, infrastructure and labor force, preferred locations will be identified. The Beluga area is remote and significant boom/bust related impacts on small communities (i.e., Tyonek) would likely result from plant construction. Socioeconomic criteria will thus be heavily weighted in the overall site evaluation process.

## 4.2 ENGINEERING SITING CONSTRAINTS

The development of the coal-gasifier combined-cycle station could be constrained by a number of factors bearing upon the engineering aspects of the project. These factors, which are discussed below, include site topography and geotechnical characteristics, access road distance, transmission line distance and water supply requirements.

### 4.2.1 Site Topography and Geotechnical Characteristics

In general, the power plant should be sited on relatively flat terrain, which will minimize the amount of required grading and excavation. It will also minimize the potential for adverse environmental impacts due to rainfall runoff transport of suspended solids to nearby waterways. The plant should also be sited above the 100-year floodplain of any major surface water resources.

Another major criterion is the avoidance of areas with poor soil conditions. Such areas can cause significant construction and reliability problems due to poor foundation suitability. Soil-related foundation problems can be expected in the Beluga area due to the presence of highly organic soil (muskeg). The presence of this soil will probably require the installation of extensive pilings under major structures.

Seismic activity can also be an important site differentiating factor, with preference given to those sites located in regions of low activity. In this study, however, all potential sites fall within regions of high seismic activity (Zone 3). While this will not preclude development nor differentiate between sites, it will increase construction costs, because more material will be required to ensure plant foundation and disposal area dike stability.

A final geotechnical criterion concerns the opportunity for use of onsite borrow material. Sites that contain an adequate supply of borrow material can be far less costly, especially if alternate sites would require hauling this material over long distances.

### 4.2.2 Access Road and Transmission Line Considerations

Siting a power plant in close proximity to existing roads and transmission lines minimizes cost and also minimizes the environmental effects associated with land disturbance. Route selection should comply with established safety and reliability standards; for example, the maximum allowable grade is approximately 6 percent. Route selection will also be affected by soil and meteorological conditions, because potential frost heave problems and other soil related characteristics can significantly add to the cost of road facilities. Also, wind, temperature and ice load can significantly affect transmission line design.

### 4.2.3 Water Supply Considerations

The power plant requires a reliable water supply source for its efficient operation. To ensure that this requirement is met, two criteria are generally employed during the siting process:

- The plant should be sited within approximately 15 miles of an acceptable source of water, and
- The plant should be sited where the maximum static head between the water source and the end use facility (the plant itself or a makeup water reservoir) is less than approximately 1500 feet.

The first criterion reflects the need to minimize right-of-way acquisition; land disruption; associated construction-related environmental impacts;

investment and operating costs; and the potential reliability problems associated with "pumps-in-series" operation. The second criterion reflects the limits of the state-of-the-art regarding the ability to pump vertically while maintaining system reliability, the need to minimize system redundancies (e.g., a duplicate pipeline), and the need to minimize the operating costs associated with water pumping.

# 5.0 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The construction and operation of a 220-MW coal-gasifier combined-cycle generating facility will create changes or impacts to the land, water, air, and socioeconomic environments in which it is located. A summary of the primary impacts of the plant on the environment is presented in Table 5.1. Following preliminary plant design, these primary effects are then analyzed and evaluated in light of existing environmental conditions to determine the potential significance of the impact and the need for additional mitigative measures. Further discussion of the impacts listed in Table 5.1 is provided below.

## 5.1 WATER RESOURCE EFFECTS

Water resource impacts associated with the construction and operation of a coal-gasifier combined-cycle power plant are generally mitigated through appropriate plant siting criteria and a water and wastewater management program. The plant water system will normally employ water treatment and recycle to satisfy regulatory requirements on discharge and to minimize water consumption. Achievement of these water quality requirements will preclude adverse impacts on the water resource. Certain waste streams in the gasifier, however, may require more extensive treatment systems than those normally associated with steam-electric or combustion turbine technologies.

## 5.2 AIR RESOURCE EFFECTS

The air resource impacts associated with a coal-gasifier combined-cycle power generation facility are relatively minor when compared with alternate fuel-combustion technologies. Nitrogen oxide emissions can be controlled through water or steam injection techniques. A major advantage of a gasifier over other coal combustion technologies is the elimination of significant sulfur oxide emissions. The associated hydrogen sulfide emissions are controlled through a treatment process, such as the Stretford process. Particulate emissions can be controlled, if necessary, through conventional techniques, such as baghouses. Achievement of regulatory requirements will preclude any significant impacts from these emissions to the air resource.

## TABLE 5.1. Primary Environmental Effects

| | |
|---|---|
| **Air** | |
| Controlled Gasifier Emissions (Anderson and Tillman 1979) | |
| Particulate Emissions | 0.009 lb/MMBtu |
| Sulfur Dioxide Emissions | 0.046 lb/MMBtu (0.0025 lb S/MMBtu)[a] |
| Nitrogen Oxide Emissions | 0.135 lb/MMBtu |
| Hydrocarbon Emissions | 0.003 lb/MMBtu |
| Carbon Monoxide Emissions | 0.010 lb/MMBtu |
| Controlled Combustion Turbine Emissions | |
| Particulate Emissions | Negligible |
| Sulfur Dioxide Emissions | Negligible (0.007 lb S/MMBtu)[a] |
| Nitrogen Oxide Emissions | Variable. Water injection controlled to meet $NO_x$ standard of 0.014 percent by volume of gaseous emissions. |
| **Water** | |
| Plant Water Requirements | 1,303 gpm wet tower operation<br>208 gpm dry tower operation |
| Plant Discharge Requirements | 222 gpm wet tower operation<br>85 gpm dry tower operation |
| **Aquatic and Marine Ecosystems** | |
| Anadromous Fish | No impact anticipated |
| Other | No significant impact anticipated |
| **Terrestrial Ecosystem** | |
| Wildlife Habitat | Loss of habitat at the plant site and along access road corridor |
| Food Chain | No significant impact anticipated |
| Human Presence | Increased human presence at plant site and along access road corridor |
| **Land** | |
| Plant | 30 acres |
| Transmission | 75 miles at 345-kV line (could share existing transmission corridor for much of this distance) |
| Road | 5 miles of gravel road |
| Ash Disposal | 50 acres |
| **Socioeconomic** | |
| Construction Work Force | Peak requirement of approximately 1000 personnel |
| Operating Work Force | 110 personnel |
| Relocations | None |
| Land Use Changes | Increased access to plant site and along road and transmission corridors |
| Recreation | See land use changes above |
| Capital Investment | 30 percent within region<br>70 percent outside region |
| Operating Investment | 84 percent within region<br>16 percent outside region |
| Fuel Purchases | 100 percent within region |

(a) Total of various sulfur compounds based on sulfur mass balance--refer to Figure 2.9.

Ice fog may be produced during cold weather conditions by water or steam injection; however, the requirement for water or steam injection may be eliminated when ice fog is deemed a traffic hazard. In addition, water vapor can be added to the air from the cooling tower. The formation of these plumes will be eliminated, however, by the use of a wet/dry cooling tower system. No offsite local climatic effects of system operation will be detectable.

As with other combustion-based technologies, operation of a coal-gasifier combined-cycle plant will release carbon dioxide to the atmosphere. Increasing concern has been expressed regarding long-term effects of the increase in atmospheric $CO_2$, apparently resulting from combustion of fossil fuels. Of particular concern is the potential "greenhouse" effect of increased atmospheric $CO_2$ concentration. No feasible measures are currently available for control of $CO_2$ production--other than possible regulation of the global amounts of fossil fuels burned. No controls on $CO_2$ production, however, currently exist.

## 5.3 AQUATIC AND MARINE ECOSYSTEM EFFECTS

A potentially significant impact can occur from water withdrawal and effluent discharge. However, proper design and location of the plant's intake and discharge structures should sufficiently mitigate any major adverse effects. Attainment of regulatory requirements on plant discharges through properly engineered systems should mitigate any potential toxic effects.

## 5.4 TERRESTRIAL ECOSYSTEM EFFECTS

The greatest impact resulting from coal-gasifier combined-cycle power plants on the terrestrial biota is the loss of habitat due to human disturbance. The amount of land required is approximately 30 acres for the actual plant site and 50 acres for the waste disposal area. A much larger area may be required for road access and transmission and pipeline corridors (see Table 5.1). Significant populations of moose, caribou, black bear and waterfowl are located in the Cook Inlet area. Therefore, siting studies for the actual plant location and for road, gas pipeline, and transmission corridors should be performed to minimize impacts to these species. A carefully selected site should not significantly impact these populations.

Some potential exists for the disturbance of the flora and fauna due to cooling tower drift emissions and coal and waste pile dusting. Proper control and site management devices should sufficiently mitigate this impact.

## 5.5 SOCIOECONOMIC EFFECTS

Most of the communities located near the Beluga coal fields are small in population and have an infrastructure that is not highly developed. In light of this, the construction and operation of a 220-MW coal-gasifier combined-cycle plant has a high potential to impact these local communities and cause a boom/bust cycle. This impact may be significant, for the largest community in the area, Tyonek, has a population of only 239. While a construction camp will mitigate this impact to some degree, disruption of the area's infrastructure must be anticipated.

Since a coal-gasifier combined-cycle power plant represents a capital-intensive technology, the largest portion of expenditures outside the region will be attributed to equipment. Approximately 70 percent of the project capital expenditures will be spent in the lower 48 states, while 30 percent will be spent within the Railbelt. Operating and maintenance expenditures spent outside the Railbelt will be approximately 16 percent.

# 6.0 INSTITUTIONAL CONSIDERATIONS

This section presents an inventory of major federal, state of Alaska and local environmental regulatory requirements that will be associated with the development of a 220-MW coal-gasifier combined-cycle power plant located in the Beluga area on Cook Inlet.

The discussion is limited to major environmental regulatory requirements. The identification of more specific requirements can be accomplished only after detailed studies regarding project design and location are available. These requirements could be important in Alaska, where much of the land is owned by the federal or state government.

## 6.1 FEDERAL REQUIREMENTS

Since the operating experience with coal gasifier facilities to date has been limited, the Environmental Protection Agency (EPA) has yet to promulgate industry-wide standards to control the waste streams emitted. In cases such as this, the EPA generally applies the limitations from an industry that closely resembles the process in question. In light of this procedure, it can be expected that the effluent limitations from a number of point source categories, including steam-electric generation, oil refining, coking, mining and coal preparation and handling, will be applied to similar waste streams occurring at a coal-gasifier combined-cycle facility. These specific point source categories are enumerated because various aspects of them have been applied to gasification plants in the past. In addition, the EPA initiated a program to develop Pollution Control Guidance Documents (PCGDs) for each major synfuel technology. The initial PCGDs were to be non-binding, non-regulatory documents to inform industrial designers and permitting officials of what EPA believes to be the best and most cost-effective ways to control pollution from synfuel plants. Second-generation PCGDs were to have more regulatory authority. Due to many reasons this program was, however, cancelled following issuance of only a few draft documents. At present it is uncertain whether the program will be reinstituted.

The permits that would be required for both a conventional coal-fired facility and the proposed coal gasifier combined-cycle power plant are identified only through their inclusion in Table 6.1. For discussion of those permits, refer to the institutional considerations section of the reports Coal-Fired Steam-Electric Power Plant Alternative for the Railbelt Region and Natural Gas-Fired Combined Cycle Power Plant Alternative for the Railbelt Region (Ebasco Services Incorporated 1982a, 1982b). Further discussion is provided here, however, of permits required for a synfuels facility that need not be obtained for a coal-fired or natural gas-fired combined-cycle plant.

Under the Toxic Substances Control Act (TSCA), a new chemical substance or one with a significant new use will trigger a manufacturer's responsibility to submit a premanufacture notification (PMN) 90 days prior to manufacturing if the chemical is not on EPA's chemical inventory. The EPA is currently considering whether synfuels are new chemicals that must be reviewed under the PMN program before production can begin. Until the consideration is complete, EPA is requesting that synfuel manufacturers submit to EPA, in advance of the PMN, a description of the chemical(s) expected to be produced. It is recommended that owners and operators of a synfuels plant file a PMN if one has not been previously filed for the system employed in their facility and the coal that the facility will process.

Applicability of the Resource Conservation and Recovery Act (RCRA) hazardous waste management program to the synfuels industry has some unique aspects worth further consideration. Congress has specifically exempted solid waste originating from the extraction, benefaction, and processing of ores and minerals, including coal, from RCRA control until studies can be completed to clarify the exact hazards of such wastes. The exemption has been interpreted by EPA (in a memo dated January 12, 1981, from Alfred Lindsey, Deputy Director of EPA's Industrial and Hazardous Waste Division) to apply to the gasification of coal, and wastes produced by gasification operations provided they are "unique" to the ore processing operation. The exemption includes wastes produced during direct gasification and liquefaction of coal, including wastes that may not become mixed with spent ash, such as sludges and condenser liquids. However, the exemption has not been applied to hazardous

TABLE 6.1. Federal Regulatory Requirements

| Agency | Requirement | Scope | Statute or Authority |
|---|---|---|---|
| U.S. Environmental Protection Agency | National Pollutant Discharge Elimination System | Discharges to Water | 33 USC 1261 et seq.; section 1342 |
| | Prevention of Significant Deterioration | Air Emissions | 42 USC 7401 et seq.; section 7475 |
| | Hazardous Waste Management Facility Operation Permit | Hazardous Waste | 42 USC 6901 et seq.; section 6925 |
| | Premanufacture Notification | Toxic Substances | 15 USC 2601 et seq.; section 2605 |
| U.S. Army Corps of Engineers | Environmental Impact Statement | All Impacts | 42 USC 4332 |
| | Construction Activity in Navigable Water | Construction in Water | 33 USC 401 et seq.; |
| | Discharge of Dredged or Fill Material | Discharges to Water | 33 USC 1251 et seq,; section 1342 |
| Federal Aviation Administration | Air Navigation Approval | Air Space for Transmission Lines | 49 USC 1304, 1348, 1354, 1431, 1501 |
| National Marine Fisheries Service/ Fish and Wildlife Service | Threatened or Endangered Species Review | Air, Water, Land | 16 USC 1531 et seq. |
| Advisory Council on Historic Preservation | Determination that Site is not Archeologically Significant | Land Use | 16 USC 402 aa et seq. |
| | Determination that Site does not Infringe on Federal landmarks | Land Use | 16 USC 416 et seq. |
| Department of the Interior - Office of Surface Mining | Surface Coal Mining Permit | Surface Coal Mining Operations | 30 USC 1201 et seq.; section 1256 |
| All Federal Agencies | Executive Order No. 11990 | Development in Wetlands | |
| | Executive Order No. 11988 | Development in Floodplains | |

wastes, such as spent cleaning solvents, cooling tower blowdown, ion exchange regeneration wastes, or wastes resulting from the refining of crude oil extracted from coal. Gasification plant operators cannot take advantage of the exemption from RCRA permitting requirements available to those who dispose of hazardous wastes with high volume wastes from coal combustion, because EPA does not include coal gasification in the definition of "coal combustion" for purposes of this exemption. An RCRA permit will therefore be necessary for this facility unless all hazardous wastes are transported off the project site for disposal.

The coal mines, coal unloading facilities and coal preparation facilities (defined as facilities where coal is crushed, screened, sized, cleaned, dried or otherwise prepared and loaded for transit to a consumption facility) will all be subject to the provisions of the Surface Mining Control and Reclamation Act (SMCRA). This act authorizes the Office of Surface Mining (OSM) to issue permits for all surface mining operations. These permits cover not only the mines themselves, but all activities conducted in connection with the mines. The OSM currently has extensive authority to impose operation and reclamation requirements on a mine-mouth power plant. Although OSM's regulations have been currently stayed from enforcement due to challenges in federal courts, they are still OSM's strategy and can be imposed should OSM prevail in the courts. (Note that the state of Alaska only regulates coal mined on state lands.)

The project will undoubtedly require the preparation of an EIS under NEPA in conjunction with the application to the Corps of Engineers for a permit to discharge dredged or fill material into a navigable waterway pursuant to Section 404 of the Clean Water Act, and a permit to construct in a navigable waterway under Section 10 of the Rivers and Harbors Act of 1899. Both of these permits must be obtained for construction of water intake and discharge structures for the proposed facility.

## 6.2 STATE REQUIREMENTS

On the state level, it is not expected that any unusual environmental regulatory requirements will be imposed upon the coal-gasifier combined-cycle facility. Explanations of state requirements, given in Table 6.2, can be found in the institutional considerations section of another report in this series (Ebasco Services Incorporated 1982a).

## 6.3 LOCAL REQUIREMENTS

The Cook Inlet region is controlled by some of the most sophisticated local requirements in the entire state of Alaska. This is largely due to its proximity to Anchorage, one of the major population centers in the state. As a result, a coal-gasifier combined-cycle plant will most likely be subject to rather detailed requirements on a local level. The plant will likely be sited in either the Matanuska-Susitna Borough or the Kenai Peninsula Borough.

## 6.4 LICENSING SCHEDULE

It is expected that the licensing schedule for this facility will closely approximate that presented for a coal-fired facility, taking about 43 months to complete. This estimated schedule may be delayed, however, due to lack of experience of regulatory agencies in evaluating synfuel technologies. These agencies may require extended periods of time for analysis of the environmental impacts of the project and for development of permit requirements to properly control those impacts.

The Matanuska-Susitna Borough is a second-class borough with powers of land use planning, platting and zoning with which development can be controlled. The Borough has acquired areawide powers for the regulation of ports and ambulances, and also controls education and the assessment and collection of taxes within its borders.

The Kenai Peninsula Borough has areawide powers of platting and zoning and can control local land use. Plans to develop land in the Borough must be approved by the local zoning board, which can regulate land use, building

TABLE 6.2. State Regulatory Requirements

| Agency | Requirement | Scope | Statute or Authority |
|---|---|---|---|
| Alaska Department of Environmental Conservation | State Certification that Discharges Comply with CWA and State Water Quality Requirements | Discharges to Water | 30 USC 1201 et seq.; section 1341 |
| | Air Quality Control Permit to Operate | Air Emissions | Alaska Statute 46.03.140 |
| | Solid Waste Management Facility Operation | Solid Waste | Alaska Statute 46.03.100 |
| Alaska Department of Natural Resources | Water Rights Permit | Appropriation of Water | Alaska Statute 46.15.030-185 |
| | Coal Exploration Permit | Development of Coal Mine on State Lands | Alaska 27.20.010 |
| | Coal Lease | Mining of Coal on State Lands | Alaska Statute 27.05.150 |
| Alaska Office of the Governor | Coastal use Permit | Land Use | Alaska Statute 46.40 |
| Alaska Department of Fish and Game | Anadromous Fish Protection Permit | Fish Protection | Alaska Statute 16.05.870 |
| | Critical Habitat Permit | Fish and Game Protection | Alaska Statute 16.20.22 and .260 |

location and size, the size of open spaces and population distribution. In addition, the Kenai Peninsula Borough has a solid waste disposal program and an air pollution control program with which the proposed power plant may be required to comply. These programs do not have permit provisions, but they do require that the plans for a proposed facility be approved by the Borough prior to construction.

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