Coal-Fired Steam-Electric Power Plant Alternatives for the Railbelt Region of Alaska

Volume XII

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

LEGAL NOTICE

This report was prepared by Battelle as an account of sponsored research activities. Neither Sponsor nor Battelle nor any person acting on behalf of either:

MAKES ANY WARRANTY OR REPRESENTATION, EXPRESS OR IMPLIED, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, process, or composition disclosed in this report may not infringe privately owned rights; or

Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, process, or composition disclosed in this report.

Coal-Fired Steam-Electric Power Plant
Alternatives for the Railbelt Region
of Alaska

Volume XII

Ebasco Services Incorporated
Bellevue, Washington 98004

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
Richland, Washington 99352

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 Ebasco personnel of 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 pulverized coal-fired steam-electric plants indicated that they may offer the potential for production of relatively low-cost power in the Region with the advantage of plant sizes that would be compatible with the modest future additional electric-demand forecast for the Region. For these reasons, pulverized coal-fired steam-electric plants of 200-MW rated capacity were selected for in-depth study. This report, Volume XII 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-gasification combined-cycle 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-Gasification 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.

SUMMARY

Substantial deposits of accessible and surface-mineable coal in the Beluga and Nenana areas 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 pulverized coal-fired power plants located in the Railbelt Region. Two locations were selected for examination: a site in the Beluga area north of Cook Inlet, and an alternative site near the community of Nenana, north of Denali National Park. Coal for the Beluga site would be taken from proposed surface mines in the Beluga coal field, and coal for the Nenana site would be taken from the existing Usibelli Mine at Healy.

Conceptual plant designs were developed for each location. The plant design selected was a 200-MW-capacity pulverized coal-fired steam-electric power plant. Mechanical draft wet/dry heat rejection was utilized as was a suite of flue gas controls sufficient to meet current New Source Performance Standards. Coal delivery to the Beluga Station would be by conveyor or truck from minemouth; delivery to the Nenana Station would be by unit train from the Usibelli Mine. Power from the Beluga Station would be transmitted to a proposed substation at Willow on the proposed Anchorage-Fairbanks intertie; power from the Nenana Station would be transmitted to a substation located at Nenana on the proposed Anchorage-Fairbanks intertie.

Cost estimates prepared for the two plants indicate an overnight capital cost of 2050 \$/kW for the Beluga Station and of 2010 \$/kW for the Nenana Station. Fixed and variable O&M costs for the stations were estimated to be 16.70 \$/kW/yr and 0.6 mills/kWh, respectively. Using delivered fuel cost estimates prepared elsewhere in the Railbelt Electric Power Alternatives Study, busbar power costs were estimated. Assuming a 1990 startup date, levelized busbar power costs were estimated to be 50 mills/kWh for the Beluga Station and 55 mills/kWh for the Nenana Station. All costs are in January 1982 dollars.

CONTENTS

FIGURES

<u>TABLES</u>

1.0 INTRODUCTION

Coal-fired steam-electric generation is a conventional, widely utilized technology that presently supplies more power in the United States than any other conversion technology. In a power plant of this type, coal is burned in a boiler, generating steam at a high pressure and temperature. This steam expands through a condensing steam turbine, which drives an electric generator. Conversion efficiencies for this type of power generation are in the vicinity of 35 percent (~9750 Btu/kWh). Efficiency is related to unit size, with larger units tending to be more efficient.

The use of this technology for power generation is as old as the electric power industry itself. It is used whenever an economic source of coal can be obtained and siting and environmental requirements can be met.

Coal-fired steam-electric generation has seen some development in Alaska, with several small plants operating in the Railbelt region. A 25-MW coal-fired plant located near Healy is operated by the Golden Valley Electric Association. The Fairbanks Municipal Utility System operates four units, totaling 29 MW, at their Chena station. Several other small units are located at the University of Alaska and at some military installations in the Fairbanks and Anchorage areas. All of these installations utilize coal from the Nenana coal fields near Healy.

Coal-fired steam-electric units can be designed for load-following capability. However, most of the large, modern, high pressure units have design limitations on rapid changes in load and are consequently base-loaded.

This technology, using conventional pulverized coal-fired boilers, is mature and presently available for power generation. An alternative form of this technology could utilize "advanced" atmospheric fluidized bed combustion (AFBC) to produce steam. With AFBC, air is forced up through a perforated plate in the bottom of the boiler and imparts a fluid motion to the bed material, which usually consists of coal and limestone. While there are a number of differences between AFBC and a conventional system, the major advantage of AFBC is that coal is burned in intimate contact with limestone, thereby greatly reducing sulfur dioxide (SO_2) emissions. Under some circumstances U.S. Environmental Protection Agency (EPA) limitations may be achieved in an AFBC system without the use of flue gas desulfurization (FGD) systems. This technology is still emerging with respect to electric utility service, although smaller demonstration atmospheric fluidized bed combustors are being used to produce heating steam. It is estimated that a 200-MW generating plant using AFBC would be available for order by 1988, and for commercial operation by 1995.

Coal-fired steam-electric generation has several significant advantages compared to other alternatives. There are substantial coal deposits to utilize in the Railbelt Region of Alaska. The technology is mature and well developed, and plants can be built that are extremely reliable.

Disadvantages of this technology include environmental effects, aesthetic intrusiveness and solid waste disposal. Environmental effects of primary concern include emissions of nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulates. Aesthetic intrusion of the plant can be significant compared to other alternatives. The disposal of large quantities of solid waste in the form of ash and spent FGD waste could also be a problem depending upon the specific site location.

Coal-fired steam-electric plants have been installed in unit sizes up to 1300 MW, although the typical range at this time is between 200 and 800 MW. At the low end, 10 MW appears to be the smallest practical size.

The power plant described in this report is fired with pulverized coal and is rated at 200 MW nominal capacity. Two potential sites are considered, one in the vicinity of the community of Nenana and the second near the Beluga district of the Susitna field (Refer to Figure 1.1). The plant is of conventional design, using dry FGD scrubbers for SO_2 control, baghouse particulate removal and wet/dry mechanical draft cooling towers for heat rejection.

Coal quality assumptions used for this study are typical of the Nenana and 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

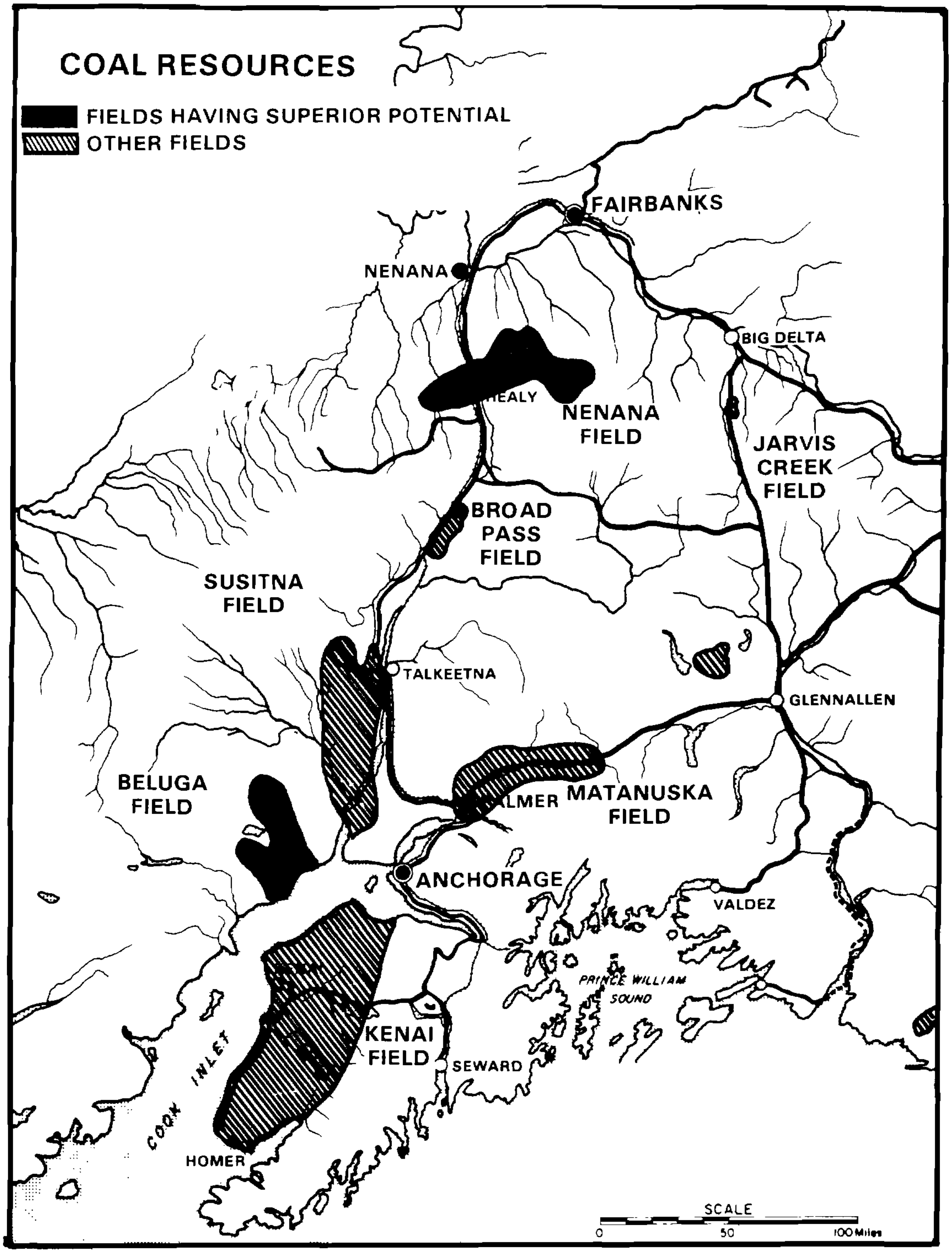


FIGURE 1.1. Railbelt Study Area

2.0 TECHNICAL DESCRIPTION

Coal-fired steam-electric generating stations are a well-known technology. Mechanically pulverized coal is mixed with air and blown into a furnace for combustion. The walls of the furnace are lined with tubing through which is passed high pressure water that is transformed into saturated steam by the thermal energy of the combustion process. The saturated steam is then passed through heat exchangers (superheaters) that are exposed to a hot flue gas stream and become superheated by absorbing more energy. The superheated steam is then piped to the steam turbine where the energy is transformed into mechanical energy. This mechanical rotating energy drives an electric generator. The steam, after releasing all of its usable energy, is condensed by cold water and pumped back into the steam-generator for reuse.

2.1 PROCESS AND AUXILIARY SYSTEM DESCRIPTION

Typical pressures for steam-electric generating stations include 1800 psig, 2400 psig and 3500 psig, with some heat rate improvement with higher pressures. Design parameters of the station described in this report have been selected to be a 2400 psig pressure rating with 1000°F superheat and 1000°F reheat temperatures and a nameplate rating of 200 MW. One-thousand degrees is the upper limit normally selected for superheating. Although the heat rate can be substantially improved with higher superheating temperatures, the industry has tended to avoid high temperatures for reliability reasons.

A process flow diagram is shown in Figure 2.1. The steam-generator will require 113 tons of coal per hour to generate 1.39 million pounds of steam per hour, with an energy of 1462 Btu per pound of steam. The coal is blown into the furnace using preheated primary air and mixed with additional preheated air for complete combustion. Nitrogen oxide (NO_x) control can be either by excess air control or by recirculation of combustion gases. Other antipollution controls are in the exhaust of the steam-generator; they include a lime slurry feed for sulfur byproduct suppression, a baghouse for particulate collection and a 270-foot stack.

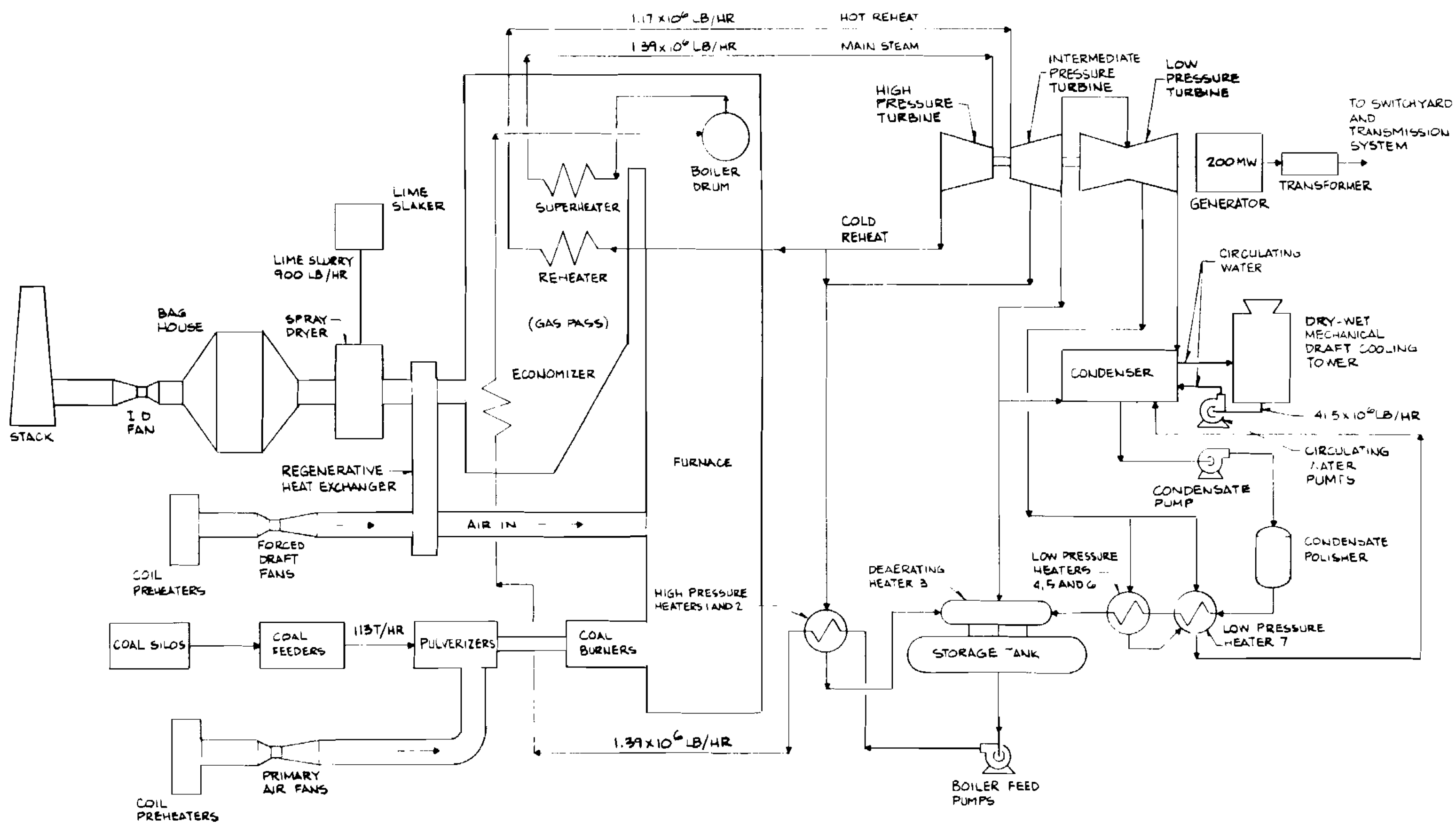


FIGURE 2.1. Simplified Process Flow Diagram

The furnace will have sootblowers on the tubing wall that will permit cleaning of the heat exchanger surfaces during operation. These sootblowers will either blow saturated steam from the drum or compressed air from special air compressors.

The steam from the steam-generator is expanded in the high pressure turbine and routed through the furnace reheater to be reheated and further expanded in the intermediate pressure turbine and subsequently the low pressure turbine. The low pressure turbine exhausts to the condenser, which operates at a vacuum, setting the pressure at which the steam condenses. Noncondensable gases are removed by vacuum pumps. The condenser is cooled by water that is recycled through a wet/dry cooling tower that exchanges the waste heat to the atmosphere by either a water-to-air (dry) heat exchanger during the winter months or by evaporation (wet heat exchange) during the summer months or by a combination of both. The choice of a wet/dry cooling tower is intended to eliminate the plume of supersaturated moisture in the air often seen over cooling towers and to minimize icing conditions in the vicinity of cooling towers. This system also reduces the overall plant makeup water requirements and therefore minimizes wastewater discharges. The anticipated water balance diagram for the power plant is presented in Figure 2.2.

The condensate from the steam cycle is pumped from the condenser through condensate heaters fed by extraction steam from the turbine to the deaerator where gases including oxygen are removed from the water. This condensate system may include a polishing demineralizer installed to provide higher water purity and to reduce the boiler blowdown rate for the system. A chemical injection system controls pH and residual oxygen concentration.

From the deaerator, the feedwater is pumped again through feedwater heaters, fed by extraction steam from the turbine, back to the steam-generator. The inlet feedwater temperature at the steam-generator is about 470°F. Here the feedwater is further heated by an economizer in the furnace exhaust to about saturation temperature.

A typical plant arrangement is shown in the plot plan (Figure 2.3). The basis is the arrangement of the turbine building, the pulverizer/heater bay

The furnace will have sootblowers on the tubing wall that will permit cleaning of the heat exchanger surfaces during operation. These sootblowers will either blow saturated steam from the drum or compressed air from special air compressors.

The steam from the steam-generator is expanded in the high pressure turbine and routed through the furnace reheater to be reheated and further expanded in the intermediate pressure turbine and subsequently the low pressure turbine. The low pressure turbine exhausts to the condenser, which operates at a vacuum, setting the pressure at which the steam condenses. Noncondensable gases are removed by vacuum pumps. The condenser is cooled by water that is recycled through a wet/dry cooling tower that exchanges the waste heat to the atmosphere by either a water-to-air (dry) heat exchanger during the winter months or by evaporation (wet heat exchange) during the summer months or by a combination of both. The choice of a wet/dry cooling tower is intended to eliminate the plume of supersaturated moisture in the air often seen over cooling towers and to minimize icing conditions in the vicinity of cooling towers. This system also reduces the overall plant makeup water requirements and therefore minimizes wastewater discharges. The anticipated water balance diagram for the power plant is presented in Figure 2.2.

The condensate from the steam cycle is pumped from the condenser through condensate heaters fed by extraction steam from the turbine to the deaerator where gases including oxygen are removed from the water. This condensate system may include a polishing demineralizer installed to provide higher water purity and to reduce the boiler blowdown rate for the system. A chemical injection system controls pH and residual oxygen concentration.

From the deaerator, the feedwater is pumped again through feedwater heaters, fed by extraction steam from the turbine, back to the steam-generator. The inlet feedwater temperature at the steam-generator is about 470°F. Here the feedwater is further heated by an economizer in the furnace exhaust to about saturation temperature.

A typical plant arrangement is shown in the plot plan (Figure 2.3). The basis is the arrangement of the turbine building, the pulverizer/heater bay

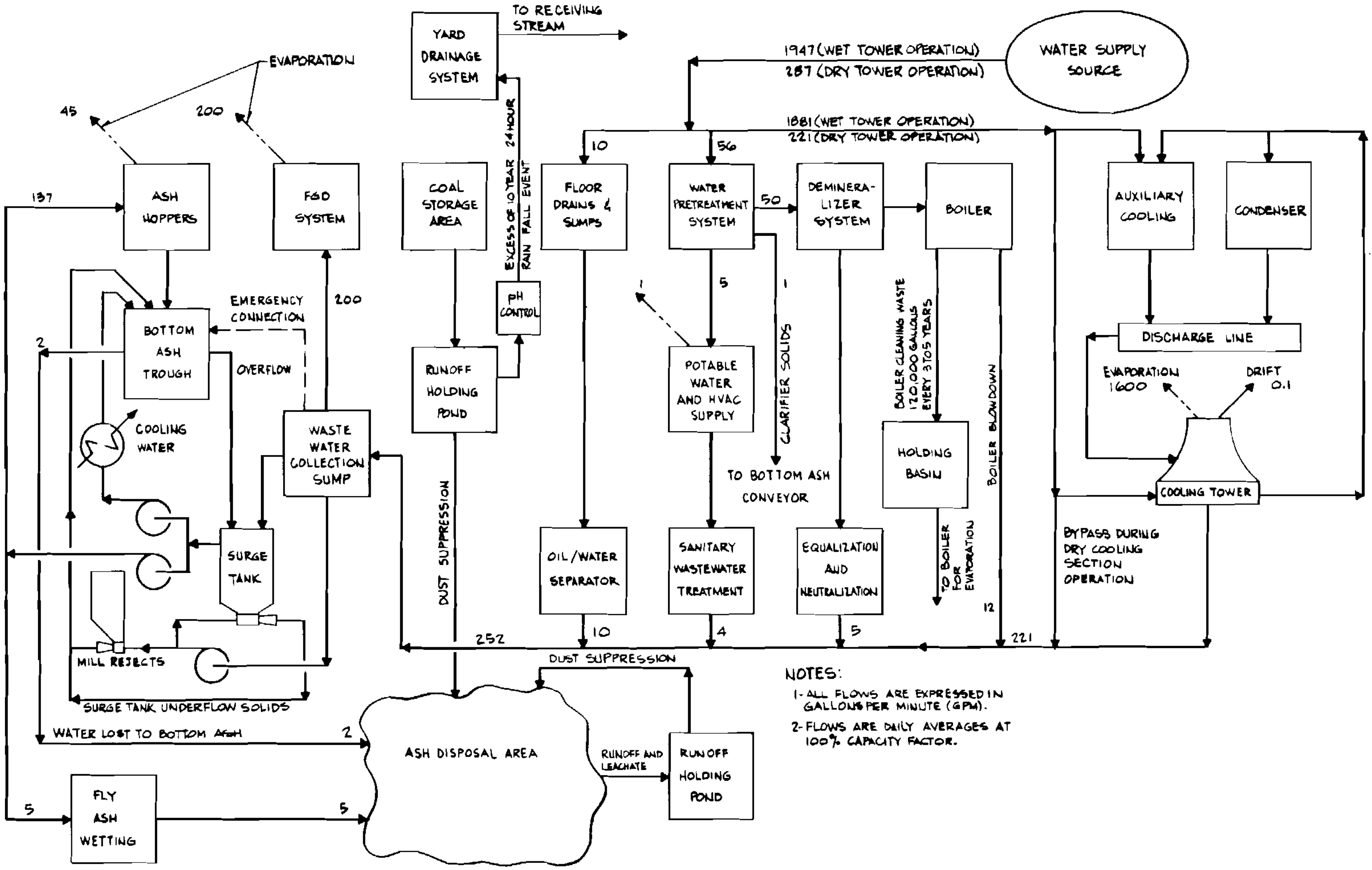
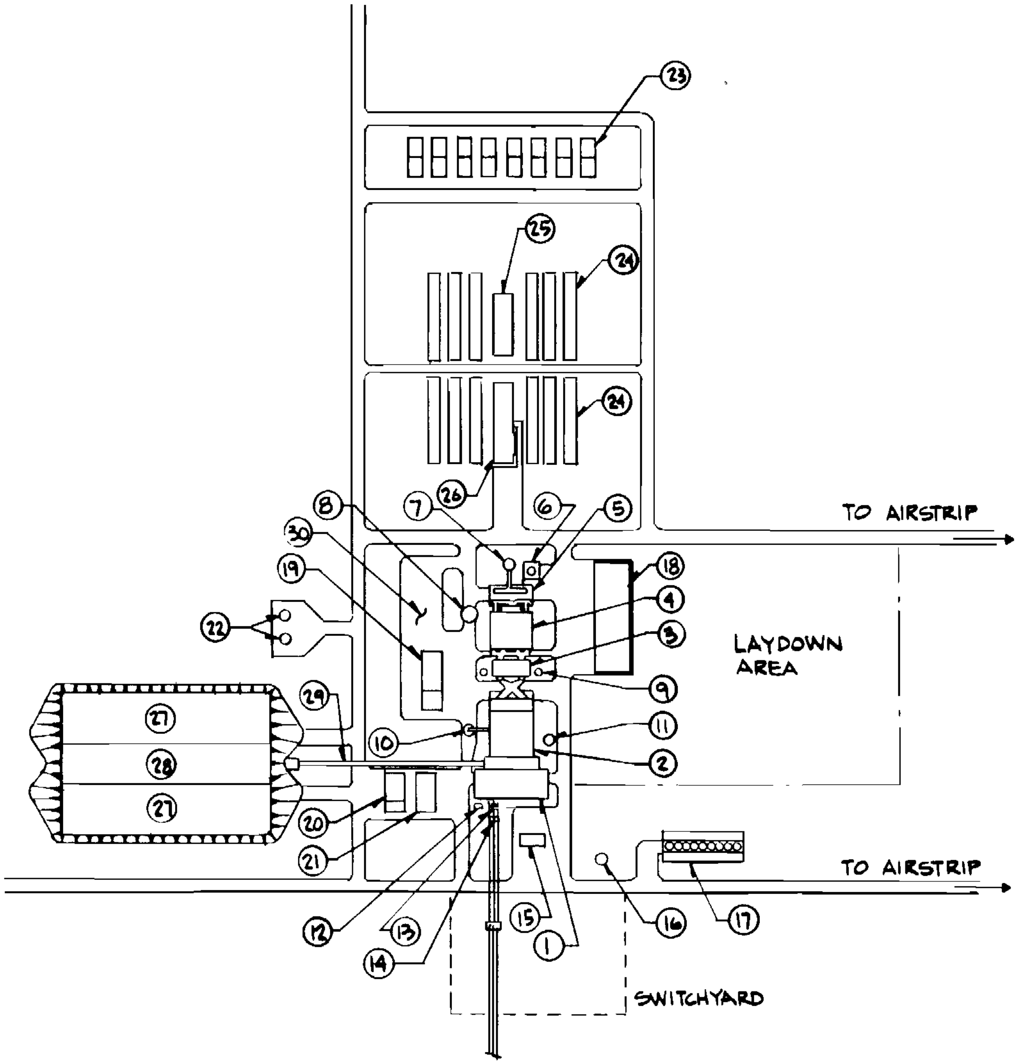


FIGURE 2.2. Water Balance Diagram



PLOT PLAN

LEGEND

1. TURBINE BUILDING
2. BOILER
3. SPRAY DRYER
4. BAGHOUSE
5. FAN HOUSE
6. LIME SLAKER
7. EXHAUST STACK
8. FLY ASH SILO
9. HYDRATED LIME STORAGE TANK
10. BOTTOM ASH SILO
11. CONDENSATE STORAGE TANK
12. START UP TRANSFORMER
13. AUXILIARY TRANSFORMER
14. MAIN TRANSFORMER
15. ADMINISTRATION BUILDING
16. RAW WATER STORAGE TANK
17. COOLING TOWER
18. INDOOR STORAGE
19. MACHINE SHOP
20. GARAGE
21. CONSTRUCTION OFFICE
22. START-UP GAS STORAGE
23. FAMILY STATUS HOUSING
24. SINGLE STATUS CAMP
25. RECREATION BUILDING
26. MESS HALL
27. COAL-DEAD STORAGE PILE
28. COAL-LIVE STORAGE PILE
29. CONVEYOR
30. CONSTRUCTION EQUIPMENT PARKING

FIGURE 2.3. Plot Plan

and the steam-generator (boiler) with its accessories that lead to the stack. The basic arrangement of the turbine building and boiler building has been chosen for compact design minimizing the length of major piping. This arrangement can be turned as a block in any direction to suit the transmission line direction and/or the fuel delivery system and water supply system.

A plot plan arrangement can be highly variable depending on the site topography, prevailing wind direction, the location of the railroad spur and access roads near the site, the direction of the transmission lines, water supply source and other factors. The suggested arrangement attempts to minimize the impact of windblown coal dust and of cooling tower moist air discharge on the other parts of the plant and on the environment.

2.1.1 Fuel Handling System

The principal components of the fuel handling system include the coal unloading station, stacking and reclaiming facilities, a coal sampling station, in-plant storage and mills.

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 Beluga site by mine mouth conveyor, and that delivery to the Nenana site will be by rail. The mine mouth conveyor at the Beluga site will feed the storage pile directly. The conveyor will be sized for a capacity of 500 tons per 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.

At the Nenana site, bottom-dump rail cars will discharge into a series of below-grade hoppers positioned directly beneath the track. From these hoppers, a conveyor tripper will distribute the coal over the length of the storage pile. One coal shipment a day will be required assuming a unit train consisting of 48 cars, each having a 50-ton capacity. Unloading will be at a rate of approximately 10 cars per hour and will require approximately 5 hours. The below grade unloading hoppers will be sized to unload two 50-ton-capacity rail cars simultaneously and feed the inclined conveyor at a rate of 500 tons per hour. The inclined conveyor will be sized identical to the Beluga site mine mouth conveyor, with an inclination not to exceed 16°.

A thawing shed will be installed just ahead of the unloading hoppers at the Nenana site. The 200-foot thawing system, sized to cover 4 rail cars each 50 feet long, will consist of infrared radiant heaters that project heat to the bottom and sides of the coal cars as they proceed through the shed tunnel. Assuming an unloading rate of 1 car every 6 minutes, a thaw shed with heaters installed along 4 car lengths will heat each car for 24 minutes by the time it reaches the dumping pit.

Stacking and Reclaiming Facilities

The compacted dead (long-term storage) pile will consist of two sections, one on each side of a below-grade reclaim tunnel, and will contain a 90-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 at full load plant operation.

The live storage pile will be covered with a corrugated galvanized sheet steel "A" frame roof. It will be supported by steel columns, beams, and rafters. This structure will also support the overhead conveyor tripper, enclosed in a penthouse at the apex of the roof. The traveling belt tripper will have a capacity of 500 tons per 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 travel will be 1400 feet.

The live storage 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 on 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 125 tons/hr. The plant's full load feed rate is 113 tons/hr.

Cost Sampling Station

A coal sampling system will be provided, either inside the plant or in a separate sample house in the yard.

In-Plant Storage

In-plant silo storage capacity will be 10 hours. Five silos, each with a capacity of 240 tons, are situated above the mills for gravity feed. They will be provided with a fire protection system. Each boiler silo will be designed for mass flow with stainless steel liners. They will be 24 feet in diameter and approximately 40 feet high. Their configuration will be as shown in Figure 2.4.

Mills

The mills (pulverizers) serve to pulverize and dry the coal in preparation for burning. There will be a total of five coal pulverizers (mills), one under each silo located at the lowest elevation of the plant. Each mill will be supplied with hot air from the air preheater. The hot air will remove moisture from the coal and transport the pulverized coal to the burners. A typical firing system is illustrated in Figure 2.5. Each mill will have a capacity of 23 tons per hour and will pulverize the coal to pass 70 percent through a 200 mesh sieve and at least 98 percent through a 50 mesh sieve.

2.1.2 Steam-Generator

The steam-generator will be an indoor type designed to burn run-of-mine pulverized coal. Main steam capacity will be 1.39×10^6 lb/hr at 2400 psi, 1005°F. The furnace will be of waterwall construction with steam drum and gas

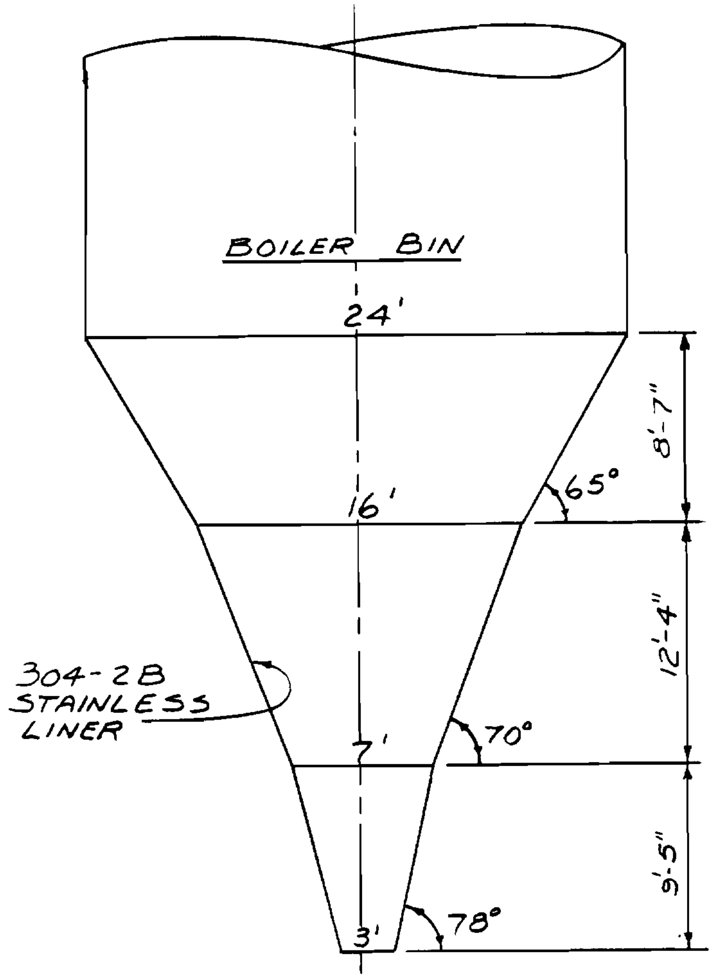


FIGURE 2.4. Mass-Flow Boiler Bin Configuration

pass superheaters, economizer and air heater. Single pass reheat will be provided with a capacity of 1.17×10^6 lb/hr at 1005°F. Economizer outlet temperature will be 470°F.

A balanced draft design will be utilized.

The steam generator will be provided with light oil torch ignition, safety valves, instrumentation and controls, a boiler blowdown system and soot blowers.

A summary of the steam generation design parameters is provided below:

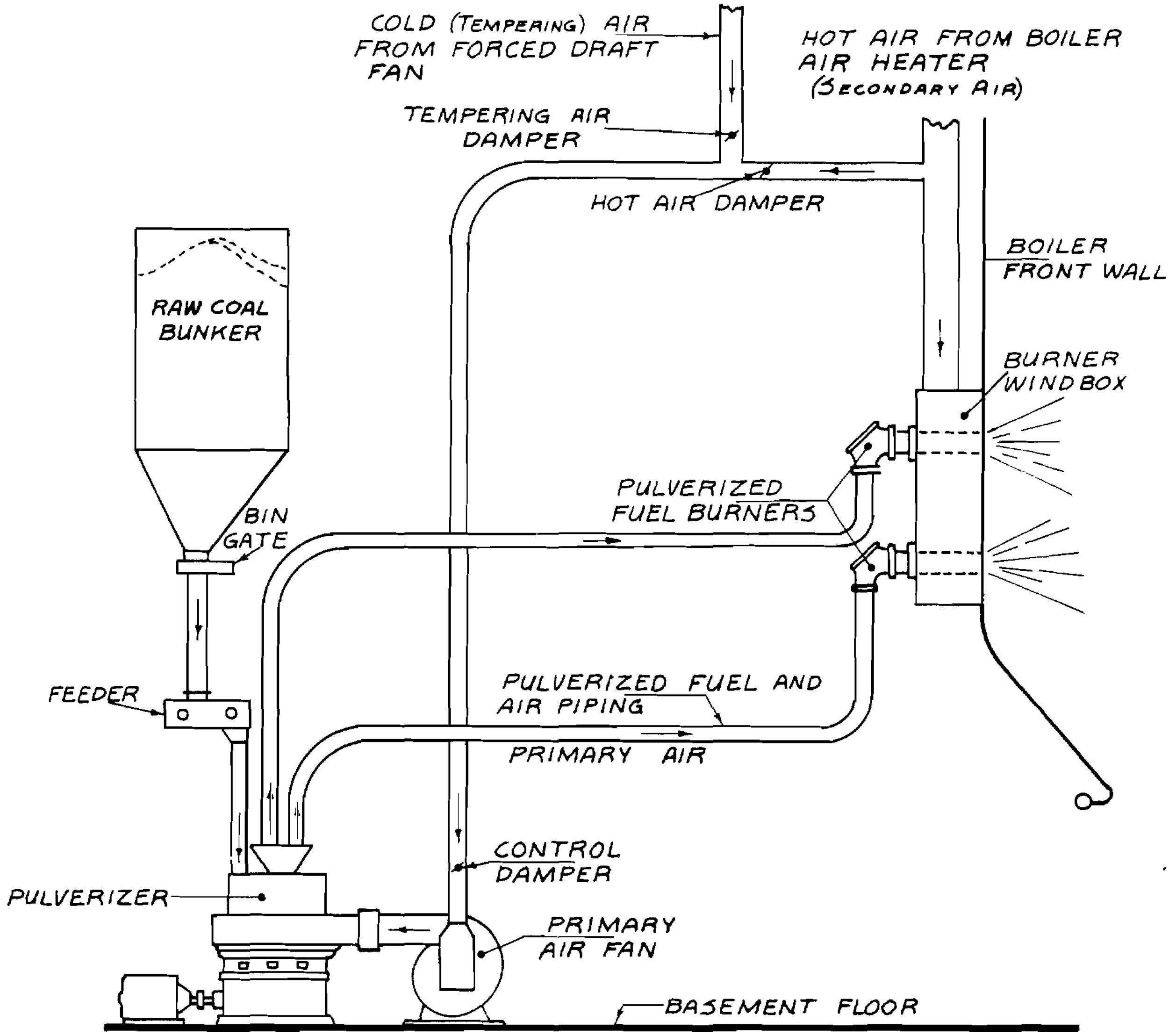


FIGURE 2.5. Typical Direct-Firing System for Pulverized Coal

Steam Flow at Superheater Outlet	1.39×10^6 lb/hr
Steam Pressure at Superheater Outlet	2525 psig
Steam Temperature at Superheater Outlet	1005°F
Feedwater Temperature at Economizer Inlet	470°F
Steam Flow Through Reheater	1.17×10^6 lb/hr
Steam Temperature at Reheater Inlet	595°F
Steam Temperature at Reheater Outlet	1005°F
Enthalpy at Reheater Inlet (Approximate)	1300 Btu

Fans and motors shall be rated as follows, referred to the maximum continuous rating of the steam-generator:

	Forced Draft Fan	Induced Draft Fan	Recirculating Fan[a]
Margin for Volume (%)	20	20	15
Margin for Static Head (%)	44	44	32
Margin for Temperature (°F)		25	100
Maximum Speed (rpm)	1200	900	900

The steam-generator will be housed in a building 135 feet square and 180 feet high. One wall will be common with an auxiliary bay of 150 feet by 55 feet and 105 feet high. The opposite 150-foot wall will be on one side common with the steam-generator wall and on the other side common with the turbine-generator building wall.

On the other side of the steam-generator building, opposite to the auxiliary bay, will be the combustion air and exhaust handling equipment leading to the stack. This building will be 135 feet wide by 200 feet long and 70 feet high, with one 135-foot wall common with the steam-generator building. All buildings will be of steel construction insulated with aluminum-sandwiched insulation.

2.1.3 Turbine-Generator

The turbine is to be of the 200 MW rating, with seven extraction stages and bottom exhaust. The seven extractions are to be used for feedwater heating and air preheating for the boiler. Turbine design conditions are as follows:

Throttle Pressure	2400 psig
Superheat Temperature	1000°F

(a) The recirculating fan may be required for NO_x control and is not illustrated in Figures 2.1 and 2.5.

Reheat Temperature	1000°F
Turbine Backpressure	1.5 in. Hg
Final Feedwater Temperature	470°F

The generator is to be designed for maximum capability of the turbine with a power factor of 0.85.

All equipment is to be designed for indoor installation. The turbine-generator is to be equipped with all local and control room supervisory instrumentation, including a valve testing station and protective devices. Oil reservoir, oil cooler, and ac and dc oil pumps as well as the gland seal system (including piping as normally supplied with the turbine-generator) are to be included.

The turbine-generator will be located on a pedestal 108 feet long, 33 feet wide and 30 feet high that is situated in a turbine building 200 feet long, 100 feet wide and 50 feet high. One section over the center of the turbine-generator will have a width of 45 feet to accommodate a bridge crane of 85 tons capacity protruding 37 feet above the basic building for a total height of 87 feet. This building will also be of steel construction, with aluminum-sandwiched insulation siding.

In addition to the turbine-generator, condenser, condensate pumps, some of the feedwater heaters, feedwater pumps and other miscellaneous equipment, the turbine building will also contain the control room, water transfer pumps, service water pumps, instrument air compressors, service air compressors, demineralizers, motor control centers, house boilers and a diesel-generator.

The house boilers are to be designed so that with both boilers in operation the buildings can be kept at 60°F, and with one boiler in operation the buildings can be maintained above a minimum of 40°F. The boilers will also provide freeze protection for all exposed equipment, including the cooling tower basin. At the Beluga site, the house boilers will be approximately 45,000 lb/hr; approximately 60,000 lb/hr will be required at the Nenana field site.

2.1.4 Electrical Plant Designs

Differing electrical plant designs will be required for Nenana and Beluga.

Nenana Station

The proposed electrical configuration for the plant at Nenana is as follows: the generator output voltage is assumed to be 20 kV (which is an average of the standard voltage used by the two largest manufacturers). The main transformer elevates this to 138 kV, the basic switchyard voltage, to match the voltage of the existing tie line to Fairbanks from Healy. The existing line will be opened and brought into the new 138-kV switchyard. Startup power for this station can be supplied from Fairbanks, from Healy, or from the south over the proposed North/South 345-kV tie line. This tie line is discussed in Section 2.3.

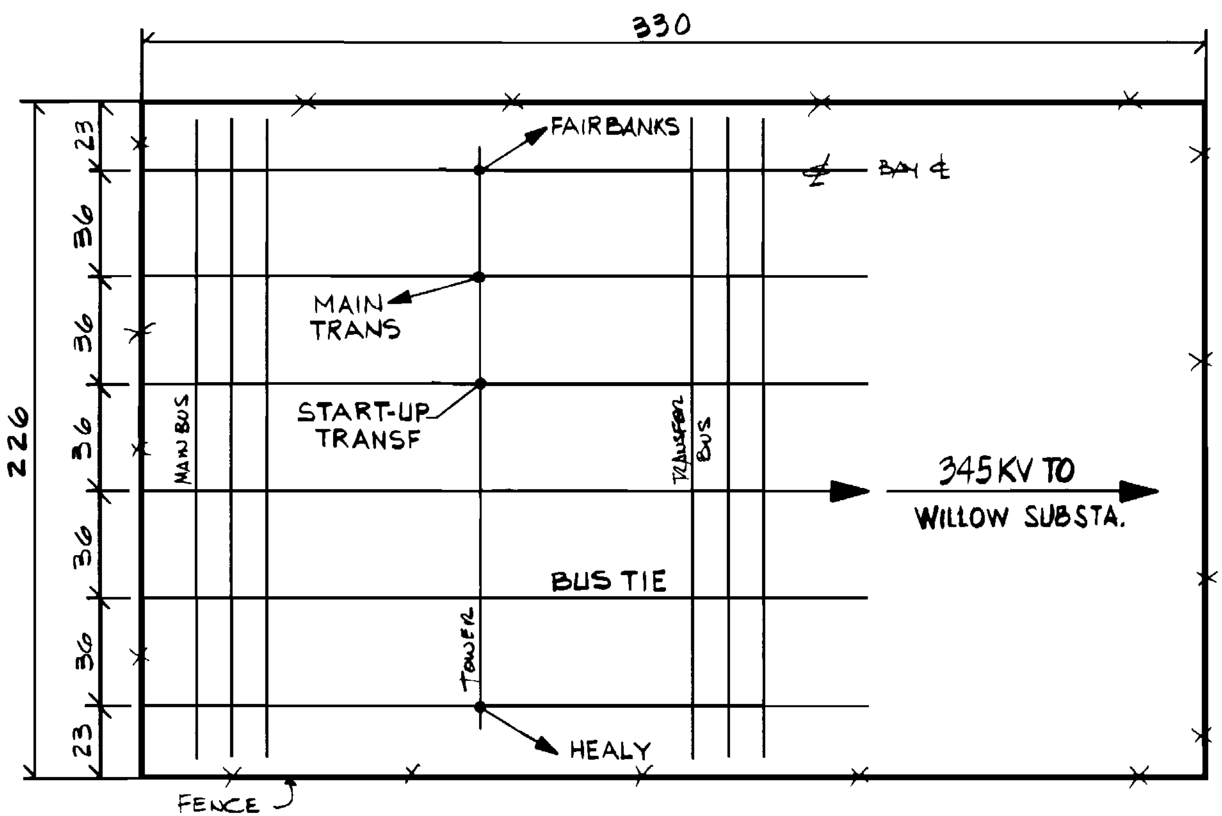
The auxiliary and startup transformers have three windings 138 kV delta to 4.16/4.16 kV. Two trains for auxiliary power buses A and B are thus setup at 4.16 kV.

Ratings of the major pieces of equipment are as follows:

- Generator, 247 MVA; 0.85 PF, 200 MW, 20 kV
- Main Transformers, 220 MVA, 20 kV delta to 128 kV wye
- Auxiliary Transformers, 3 winding 20 MVA, 20 kV delta to 4.16/4.16 kV delta
- Startup Transformer, 3 winding 20 MVA, 138 kV delta to 4.16/4.16 kV wye
- Switchgear 4.16 kV medium voltage Bus A and Bus B, 2000 Amp 350 MVA, approximately 10 air circuit breakers each
- Power Centers, motor-control centers distribution panels, etc., as required.

The switchyard configuration is shown in Figure 2.6. Major pieces of equipment are as follows:

- Main and Transfer Buses



NOTE:
SEE FIGURE 2.7 BELUGA STATION
SWITCHYARD FOR SIMILAR CONFIGURATION
WITH MORE DETAIL

FIGURE 2.6. Nenana Station Switchyard

- Six 138-kV bays each consisting of one 138-kV circuit breaker and three 138-kV disconnect switches. These bays are used for the main transformer, startup, bus tie lines to Fairbanks and Healy and the 345-kV autotransformer.
- One 345-kV bay with two disconnect switches and circuit breaker for the 345-kV line to the Willow Substation.

Beluga Station

The proposed electrical configuration for the plant at Beluga is as follows. The generator output voltage is assumed to be 20 kV (same as Nenana). The main transformer elevates this to 169 kV, the basic switchyard voltage.

Since the existing combustion turbine plant near Beluga is transmitting at this level, a tie line between the two plants at 169 kV will improve reliability of the overall system and supply startup power for the Beluga Station. The output of the new plant will be elevated to 345 kV through an autotransformer and transmitted to a proposed new 345 kV substation at Willow, which has outlets to the north (Fairbanks) and to the south (Anchorage). This substation and associated tie lines are discussed in Section 2.3. The auxiliary and startup transformer setups would be the same as Nenana.

Ratings of the major pieces of equipment are the same as Nenana, except the main transformer will be 200 MVA, 20 kV delta to 169 kV wye. The switchyard configuration is shown in Figure 2.7.

Major pieces of equipment are as follows:

- Main and Transfer Buses
- Five 169-kV bays each consisting of one 169-kV circuit breaker and three disconnect switches. These bays are used for the main transformer, startup, bus tie line to the existing Chugach Electric Beluga plant, and the 345-kV autotransformer.
- One 345-kV bay with two disconnect switches and circuit breaker will be for the 345-kV line to Willow.

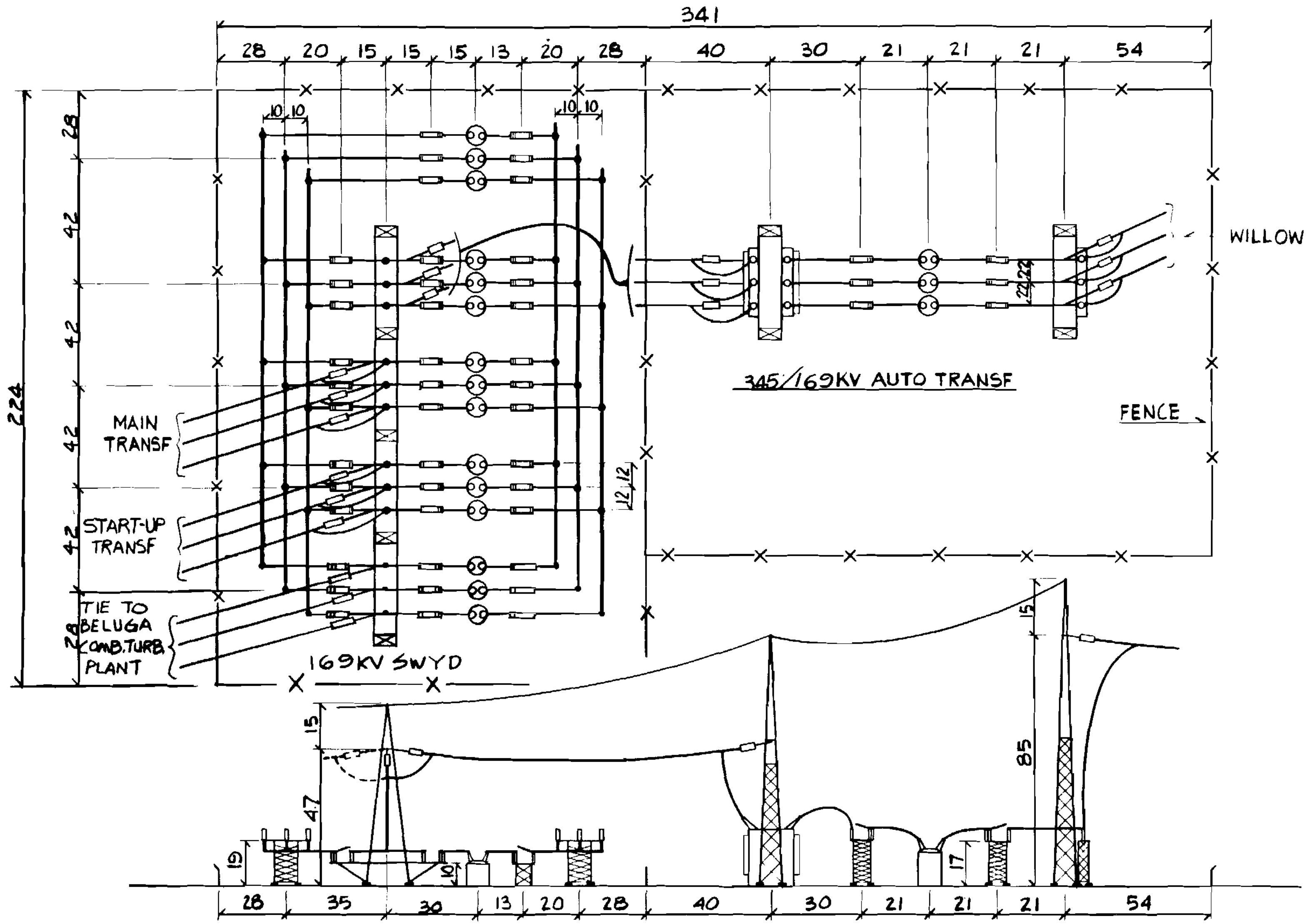


FIGURE 2.7. Beluga Station Switchyard

2.1.5 Heat Rejection System[a]

The steam exiting the turbine is condensed and returned to the boiler for reuse. The condensing is effected in the condenser where circulating cooling water is used to cool the steam. The circulating cooling water is passed through a cooling tower for conveying the rejected heat to the atmosphere.

The condenser is to be a single shell two pass with divided water box and hotwell. The hotwell is to have enough storage to allow proper level control for surging and shall be properly baffled to keep the condensate at saturation temperature. The condenser shall include Muntz Metal tube sheets and inhibited Admiralty tubes with 70-30 copper nickel tubes in the air removal sections and the impingement areas. The condenser is to be shop fabricated, including tubing, and should be suitable for sea and barge shipment. The condenser will be used in a wet/dry cooling tower application. It should include an 18-foot condenser neck with dogbone-type rubber expansion joint for connection to the turbine exhaust. Condenser design data are as follows:

Heat load	946×10^6 Btu/hr
Tubes	1" 18 BWG x 36 ft
Maximum Water Velocity	6.5 ft/sec
Cooling Water Flow	41.5 lb/hr
Surface Area	120,000 ft^2
Backpressure	1.5 in. Hg

The cooling towers for the two sites will differ considerably. The towers shall be of the wet-dry-type mechanical-draft design of a material most suitable for very cold weather conditions as found in Alaska south of Fairbanks. The intent is to have low water consumption, avoid visible tower plumes and minimize icing conditions. The tower for the Nenana plant location will have a far greater percentage of capacity in the dry portion of the tower than in

(a) While there may be some potential for using waste heat from the Nenana power plant for district heating purposes, an analysis of this option was considered to be outside the scope of this study, as use of this energy source would have little impact on the demand for or the cost of electrical energy.

the wet section, compared to the tower that would be used for the Beluga plant location. The significant data are as follows:

Heat Load	1.0×10^9 Btu/hr
Water Loading	41.5×10^6 ft/hr
Cold Water Temperature	80°F

The above is based on a 23°F approach to a 10 percent of the time wetbulb temperature of 57°F at Anchorage and a 21°F approach to a 59°F wetbulb temperature at Fairbanks. The design coldest drybulb temperature 97.5 percent of the time is -20°F for Anchorage and -50°F for Fairbanks.

Three circulating water pumps of the vertical pit type for cooling tower basin installation are required. The pumps are to be mounted 4 feet above water level in an enclosed structure. The thrust bearing should be in the motor and the shaft bearings should be of cutless rubber design of the self-lubricating type. Each pump is to be designed for the following capability:

Water Temperature	40 to 80°F
Water Flow	14×10^6 lb/hr
Total Dynamic Head	70 ft
Speed	720 rpm

The pump length should be kept to a minimum so that at 130 percent capacity the required net positive suction head (NPSH) is not exceeded. The pumps shall also be designed to run at 130 percent capacity and have a steadily rising characteristic toward shutoff for parallel operation.

2.1.6 Condensate and Feedwater System

The condensate and feedwater system receives condensate from the condenser hotwell at a temperature of approximately 40 to 80°F and a pressure of 1.5" Hg. The condensate is passed through a polishing demineralizer,[a]

(a) The polishing demineralizer may not be required and is not included in the cost estimates.

four condensate heaters, a deaerating feed tank and is then raised to steam-generator pressure by feedwater pumps (Figure 2.1). After passing through two high pressure feedwater heaters, the feedwater is supplied to the steam-generator at a temperature of 470°F and a pressure of approximately 2500 psi. The principal equipment in the condensate and feedwater system includes the condensate pumps, condensate and feedwater heaters (including the deaerating feed tank) and feedwater pumps.

Condensate Pumps

Three vertical motor-driven canned pumps designed for indoor installation are required. Each will have a capacity of 50 percent. The thrust bearings will be in the motors. The capabilities of each pump and motor are as follows:

Condensate Temperature	100°F
Condensate Flow	585×10^3 lb/hr
Total Dynamic Head	600 ft
Speed	900 rpm

The condensate pump length should be such that the distance between impeller eye and suction flange shall not be less than NPSH required when running at 130 percent of design capacity. The pumps shall be designed for parallel operation over the full range of operating capacity.

Condensate/Feedwater Heaters

The feedwater heating system will have six closed-type feedwater heaters and one open-type feedwater heater (deaerator). The closed-type feedwater heaters consist of two high pressure heaters and four low pressure heaters. The high pressure heaters will be of hemispherical head design and the low pressure heaters will be bolted head channel design. The high pressure heaters are of the integral desuperheating and draincooling design. The low pressure heaters are to have integral drain coolers. The high pressure heaters will cascade drain to the deaerator and the low pressure heaters will cascade drain to the condenser. All heaters shall be of the U-tube removable shell design complete with roller-type supports.

The U-tubes in the high pressure heaters are to be Monel, 5/8 inches in diameter. For the low pressure heaters, they are to be 90-10 copper-nickel and 3/4 inches in diameter. Representative design data for the heaters are as follows:

	Channel (psig)	Shell (psig)	Steam Flow (10^3 lb/hr)	Channel Flow (10^6 lb/hr)	Surface (ft^2)
HP-1	3700	640-Vacuum	115.0	1.31	8020
HP-2	3700	275-Vacuum	55.2	1.31	5300
LP-4	350	75-Vacuum	55.4	1.17	4590
LP-5	350	50-Vacuum	57.0	1.17	5500
LP-6	350	50-Vacuum	31.0	1.17	5630
LP-7	350	50-Vacuum	45.0	1.17	7450

The deaereator mounted on top of a five-minute capacity storage tank is to be integrally connected and equipped with stainless steel troughs and baffle plates. Design conditions for the deaerator are as follows:

Water Storage	110 x 10^3 lb
Water Flow (In)	1.17 x 10^6 lb/hr
Steam and Drain Flow	140 x 10^3 lb/hr
Water Flow (Out)	1.39 x 10^6 lb/hr
Design Pressure	150 psig
Operating Pressure	120 psia

Feedpumps

Three motor-driven, 50-percent-capacity feedpumps for indoor installation will be required. The feedpumps are to be of the multistage barrel-type with an interstage takeoff for reheat desuperheating. Each feedpump is to be complete with motors, shaft-driven and electric-driven oil pump, oil cooler and oil tank, all mounted on a common base plate. The glands are to be sealed by mechnical seals. Each pump is to be designed for the following capability:

Feedwater Temperature	340°F
Feedwater Flow	695×10^3 lb/hr
Total Dynamic Head	6900 ft
Suction Pressure	100 psig
Net Positive Suction Head	less than 50 ft
Speed	3600 rpm

The pumps should be able to operate out to 130 percent flow and the characteristic should be steadily rising toward shut-off without exceeding 120 percent of the design head.

2.1.7 Water Quality Control

The anticipated water balance for the power plant was presented in Figure 2.2. Due to the fact that "dry" solid waste disposal systems and a wet/dry cooling tower will be utilized at this station, the only station blowdown that will occur will be excess coal pile runoff and yard runoff. Coal pile runoff discharge will be relatively infrequent as all precipitation and snowmelt percolating and running off the coal pile will be collected in a holding basin designed to contain the one-in-ten-year, 24-hour rainfall event. Impounded water will subsequently be utilized for dust suppression and equipment washdown purposes. The anticipated concentrations of impurities in this waste stream following treatment are presented in Table 2.1.

Various water and wastewater treatment facilities are routinely incorporated into a power plant design to produce boiler feedwater and permit the reuse of process water. The facilities that will be required for this station are briefly described below. It should be noted that a small wastewater treatment/recycle facility may be required to treat either cooling tower blowdown or bottom ash trough water to allow recycle and insure a zero discharge mode of operation. Based upon existing data, this system does not appear to be required and therefore is not described below or included in the cost estimates.

TABLE 2.1. Estimated Characteristics of Treated Coal Pile Runoff

Parameter	Concentration[a]
Total Dissolved Solids	250
Suspended Solids	50
Iron	20
Magnesium	25
Sulfate	25
pH (units)	6.0 - 9.0

(a) All concentrations expressed in mg/L unless otherwise noted.

Boiler Feedwater Makeup Treatment System

The boiler feedwater makeup treatment system is designed to provide demineralized water for steam cycle makeup, including boiler blowdown and sootblowing purposes, as well as potable, heating, ventilating, and air conditioning requirements (Refer to Figure 2.8). The treatment system will consist of two major stages: pretreatment and demineralization. Pretreatment accomplishes the removal of suspended particulate material and residual organics and will consist of gravity filtration and activated carbon filtration. Following pretreatment, steam cycle 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 producing 50 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

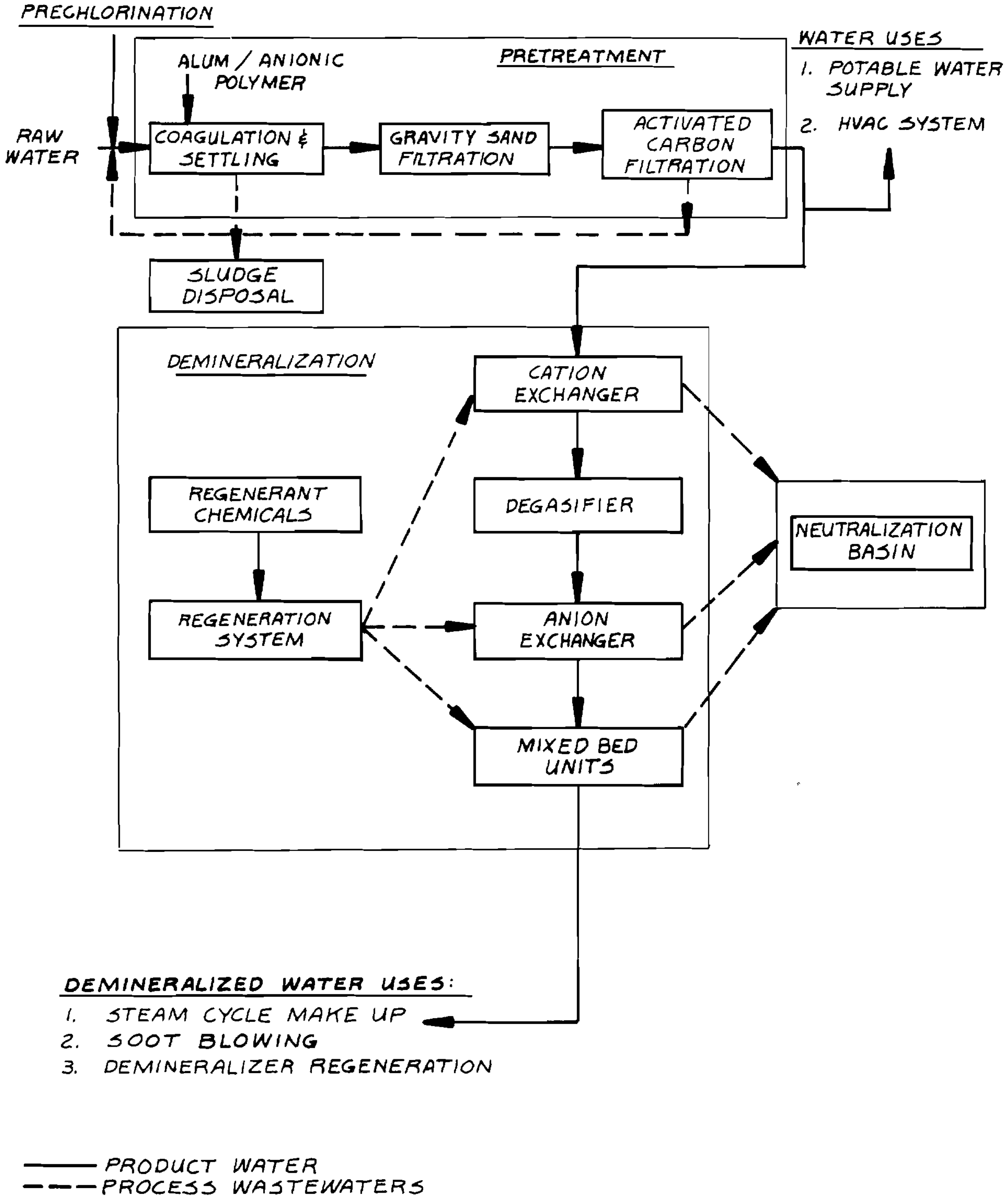


FIGURE 2.8. Boiler Feedwater Treatment System

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 wastewater collection sump for reuse.

Equalization/Neutralization Facility

Wastewater from demineralizer regeneration and condensate polisher 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 wastewater will then be discharged to the wastewater collection sump. The tank will have a minimum 36-hour detention period for the wastewater flows generated on the maximum regeneration activity day. The capacity of the tank will, therefore, be approximately 10,000 gallons. This capacity, together with the pH control system, will provide adequate neutralization to enable wastewater reuse.

Coal Pile Runoff Holding 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 for treatment prior to disposal to the yard and area drainage system.

The holding pond will provide gravity setting for coal fines (suspended matter) washed out of the pile. The pond 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. For the plant located near the Beluga coal field, the runoff holding pond will have a capacity of approximately 470,000 gallons, a surface area of approximately 6250 ft^2 and a water depth of approximately 10 feet. The capacity of the pond associated with the Nenana coal field plant will be approximately 700,000 gallons, encompassing approximately 9400 ft^2 at a 10-foot water depth. 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.

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.

2.1.8 Air Quality Control

Due to the low sulfur content in the coal (0.2% by weight) and the stringent emission requirements of the New Source Performance Standards, the air quality control configuration for the plant will be a semi-dry flue gas desulfurization (FGD) system followed by a fabric filter baghouse.

The FGD system will consist of two spray dryer vessels using a lime slurry. The FGD system will be designed to remove 70 percent of the sulfur dioxide from the gas stream at rated load, which corresponds to 1.6×10^6 ACFM[a] at 250°F. Control of the spray dryer will be governed by both the temperature and SO_2 concentration of the exit flue gas. The flow of lime to the system will average 900 pounds of lime per hour. Lime pebbles will be hydrated onsite by a single slaker with a capacity of 900 pounds of lime per hour and pneumatically transported to two storage silos each located near a spray dryer. Each silo will have a 3-month holding capacity, a volume of approximately 39,000 ft^3. Each silo will also be approximatey 55 feet high with a diameter of approximately 30 feet and include a 15-foot conical

(a) Actual Cubic Feet per Minute.

section. From the silos, the hydrated lime will be pneumatically transported to mixing tanks provided below each spray dryer vessel. The two mixing tanks will be sized for a 10-day capacity, with each tank requiring a volume of approximately 3200 ft^3. Each tank will also be about 12 feet high, with a diameter of approximately 20 feet.

The fabric filter baghouse for particulate removal will consist of four parallel rows of compartments. Fabric filters will be designed to achieve a particulate removal efficiency of 99.75%, in order to achieve a maximum emission rate of 0.03 lb per 10^6 Btu heat input to the boiler. Filter cleaning will be by both reverse air and shaker methods and will be automatically programmed to be activated every 1/2 hour to 1 hour. The baghouse and associated ash hoppers will be weather enclosed. Filter bags will be synthetic fabric coated with acid-resistant polymer resin for a service life of approximately 3 years. Continuous baghouse hopper ash removal will be required via a pneumatic conveyor to a flyash storage silo. The conveyor will be sized for 22,000 lb/hr.

2.1.9 Ash Handling System

A steam-generator that burns coal produces solid refuse classified, in general, as ash. The ash is of two types: bottom ash and fly ash. Bottom ash is the material dropped out of the combustion products in either a dry or molten state to the furnace bottom and collected in water impounded in bottom-ash hoppers. Fly ash consists of fine particles that leave the furnace with the flue gas and are collected in the baghouse system.

The total quantities of ash to be generated are a function of the ash content of the coal and the steam-generator coal-firing rate. Based upon the coal quality and the plant's design specifications discussed in previous sections of this report, and assuming a fly ash/bottom ash ratio of 70/30, the anticipated quantities of ash are as follows:

	Average	Maximum
Total Ash Production Rate	9.0 tons/hour	12.0 tons/hour
Bottom Ash Production Rate	2.7 tons/hour	3.6 tons/hour
Fly Ash Production Rate	6.3 tons/hour	8.4 tons/hour

Bottom Ash

The bottom ash will be continuously removed from the boiler. A water-filled trough is to be located below the boiler hopper openings and will contain a steel-drag bar-chain conveyor arrangement. This equipment will be sized for a maximum capacity of 3.6 tons per hour based on a maximum coal ash content of 11 percent. At the end of the trough, the drag bar will lift the ash out of the water to an elevation about 20 feet above ground level. In doing so the ash will be automatically dewatered to a moisture content of approximately 20 percent and then discharged onto a conveyer belt. This conveyer will bring the ash to a storage silo. This silo will be located next to the boiler house and is to be 30 feet in diameter and 8-1/2 feet high, with a conical section 15 feet long. The silo will be raised to allow 15 feet clearance for ash trucks. Special ash trucks of about 50-ton-capacity will transport the ash to the permanent disposal site.

Fly Ash

The fly ash collected in the baghouse hopper and in the duct hoppers and the baghouse, will be transported pneumatically (or by vacuum) to a fly ash storage silo. This silo is to be 40 feet in diameter and will have a 20-foot vertical section with a 20-foot cone. The silo will be raised to allow a 15-foot clearance for loading the ash trucks below. Trucks will transport the ash to the final disposal site. Plant process waste water will be used to wet down the fly ash to prevent the wind from carrying the ash away and to maximize ash compaction at the disposal site.

2.1.10 Solid Waste Disposal System

From the storage silos located at the plant site, all plant solid waste 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 waste quantities generated over the 35-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. The final placing and compaction of the ash will be carried out by a large rubber-tired spreading dozer.

To ensure compliance with the provisions of the Resource Conservation and Recovery Act and the state's solid waste management regulations, the disposal area will be lined with an impermeable synthetic liner. 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 leachate 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 ash.

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 ash pile will be collected behind a small berm located at the anticipated toe of the ash pile. This water will then be utilized for ash pile dust suppression.

Because winter conditions could prevent the transportation of ash from the plant to the final disposal site, should this distance prove to be considerable, a temporary emergency ash storage area will be provided at the plant.

To prevent water pollution, the area will be designed like a pond and will be 6 feet deep, 150 feet long, 50 feet wide at the rim, and lined with 3 feet of clay.

2.1.11 Other Major Plant Equipment

Other equipment required for plant operation will include:

- Two condenser vacuum pumps, 6.5 scfm at 70°F free dry air at 1-inch absolute and 475 scfm at 70° free dry air at 15-inch absolute condenser pressure.
- Two vertical pit-type service water pumps, 4000 gpm each, 80 feet head.
- Three instrument air compressors, 150 scfm, 100 psig, oil free air with receiver and dual instrument air dryer.
- Two sootblower air compressors, 700 scfm at 300 psig.

- One service air compressor, 520 scfm at 100 psig.
- Sixteen pumps, 200 to 600 gpm and 100 to 300 feet head for miscellaneous services.

All above listed equipment will include motors, baseplate, heat exchangers, receivers, controls, oil pumps, etc., as necessary to make them complete units.

2.2 FUEL SUPPLY

A principal factor in the selection of the reference locations for the plants described in this report was the availability of fuel. The Beluga Station would be located in sufficient proximity to the Beluga Coal Field to allow delivery of coal by truck or conveyor. The Nenana Station would be located near the Alaska Railroad in the vicinity of the community of Nenana, allowing delivery of coal from the Usibelli Mine at Healy by unit train or multiple carload lots. A location remote from the Nenana coal field was chosen to minimize potential conflict with the Class I Prevention of Significant Deterioration air quality area at Denali National Park.

2.2.1 Nenana Station

The proposed Nenana Station would receive coal from the existing Usibelli Coal Mine at Healy. Deliveries would be by the Alaska Railroad using a unit train or by multiple carload lots. A once-daily unit train operation could be supported by a consist of locomotives and 45 bottom-dump hoppers of 50-ton capacity.

The Usibelli Coal Mine produces coal from the Nenana Field, currently at a rate of about 700,000 tons per year (TPY). Existing production is directed to the 25-MW mine mouth Healy Generation Plant of Golden Valley Electric Association. Additional coal is crushed and delivered via the Alaska Railroad to the Fairbanks Municipal Utilities System coal-fired units at Fairbanks (29 MW), the University of Alaska cogeneration units (13 MWe) and military installations at Clear AFB, Eielson AFB and Fort Wainwright (37 MWe). No export coal is currently shipped, although test shipments have been made to Korea.

Existing mine capacity is about 2 million TPY, and with the possibility of expansion, by addition of draglines, to 4 million TPY. At this higher rate of production, mine life would be expected to be about 60 years (Swift 1981). Maximum consumption for the 200-MW plant described in this report could be expected to be about 950,000 TPY,[a] resulting in total mine production of 1,650,000 TPY, well within existing production capabilities.

The quality of Nenana coal is as follows:[b]

Heating Value (average)	8000 Btu/lb
Ash Content	7-8% average, 11% maximum
Moisture	25-30%
Hardgrove Grindability Index	~34 as mined
Ash Softening Temperature	2100°F
Ash Na_2O	0.08%
Sulfur	<0.25%
Nitrogen	0.60%

2.2.2 Beluga Station

The proposed Beluga Station would use coal from the currently undeveloped Beluga Field. The plant would 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 would 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 4.4. Production levels

(a) Assuming a maximum capacity factor of 87%.
(b) Note that a composite "Railbelt Standard" coal (Section 1.0) was used for plant design.

of up to 11,700,000 TPY could be sustained for 30 years without significant depletion of the reserves that have received the greatest attention (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, 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.

In conclusion, it appears that coal could be available by 1988 in the Beluga area given either 1) the development of an export market; or 2) installation of substantial (800 MW) electric power generating capacity. A capacity increment of this size, however, does not appear to be warranted in this time frame.

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

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.

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

2.3 TRANSMISSION LINE SYSTEM

An engineering report prepared by Commonwealth Associates (1981) recommends construction of 160 miles of new transmission lines at 345 kV from Healy to Willow with 138 kV exits at Healy and Willow. However, this study did not consider the 200-MW plants proposed at Nenana and Beluga in this report.

Using the Commonwealth report as a basis, and in the absence of a transmission line study including plants proposed in this report, the following transmission line arrangement is suggested (refer to Figure 2.9). The hub of the transmission system would be a 345-kV substation at Willow (refer to Figure 2.10). Transmission lines (345 kV) from Anchorage, Beluga, and Nenana would terminate here. This substation will provide flexibility and reliability to the system load flow. The tie line to the north would run approximately 160 miles to the proposed 200-MW Nenana Station. The existing 138-kV line from Fairbanks to Healy would be opened and connected into the Nenana Substation. This arrangement will allow Fairbanks, Healy, and the tie line to Willow to receive the power generated at Nenana. This flexibility will also allow startup power to be drawn from any of these possible sources. The switchyard voltage level of 138 kV at Nenana was selected on this basis.

Using the projected peak demands for Anchorage and Fairbanks through the years 1984-1995 (as listed in the Commonwealth report) and assuming no further generation is added in Fairbanks as replacements or new units, the Nenana area plant can supply Fairbanks needs for many years. Assuming the coal supply is adequate, additional units can be added to Nenana as required. Additional 138-kV lines may be necessary to Fairbanks as well as increasing the capacity of the existing line. The size of the 345/138-kV autotransformer at Nenana will be determined after a study indicates the anticipated load flow on the tie line.

A new 345-kV line of approximately 75 miles in length, from Willow to the proposed 200-MW Beluga Station will tie the output of this plant into the system. Again, the sizing of the autotransformer for the 345-kV line must be

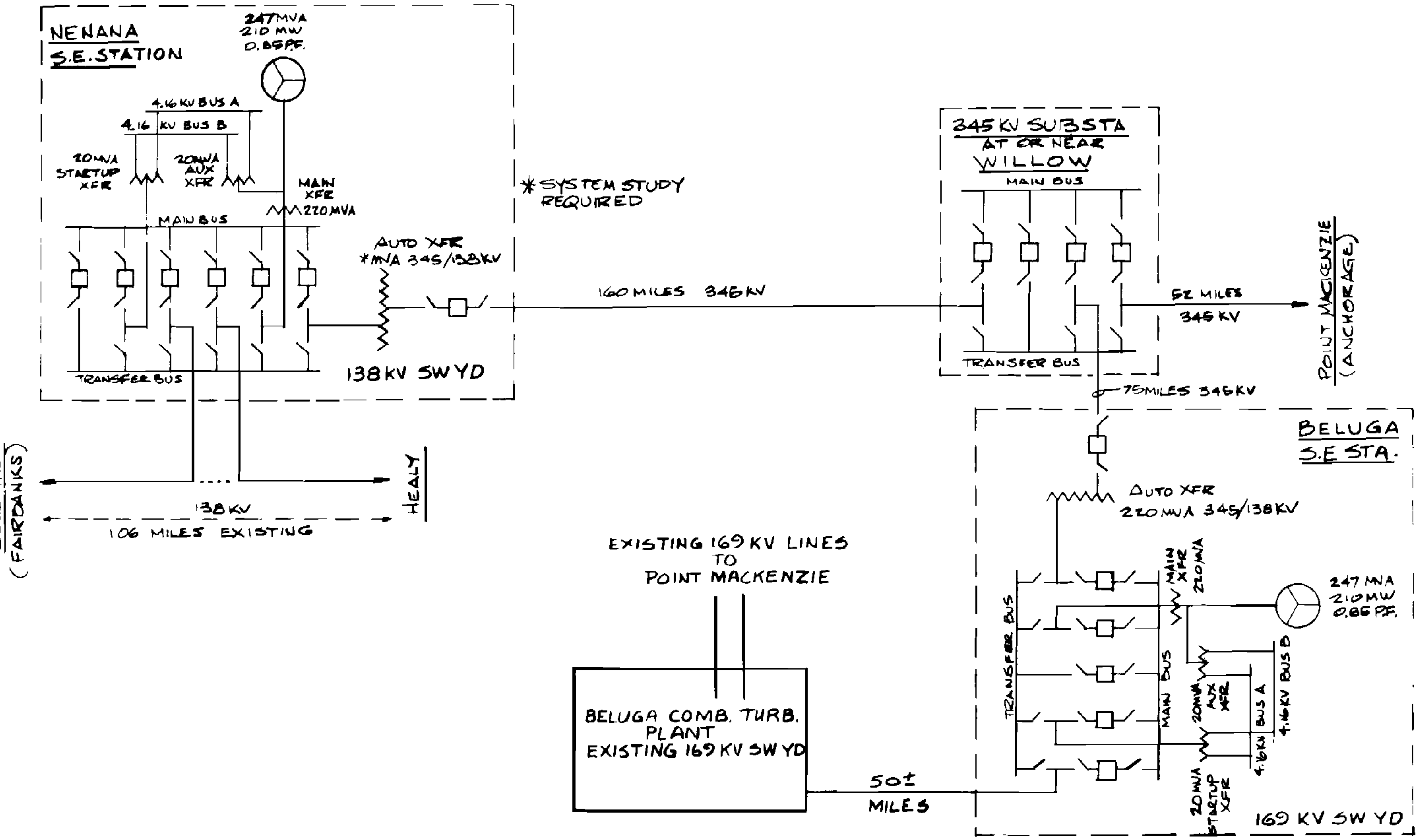


FIGURE 2.9. Nenana and Beluga Station Switchyards and Tie Lines

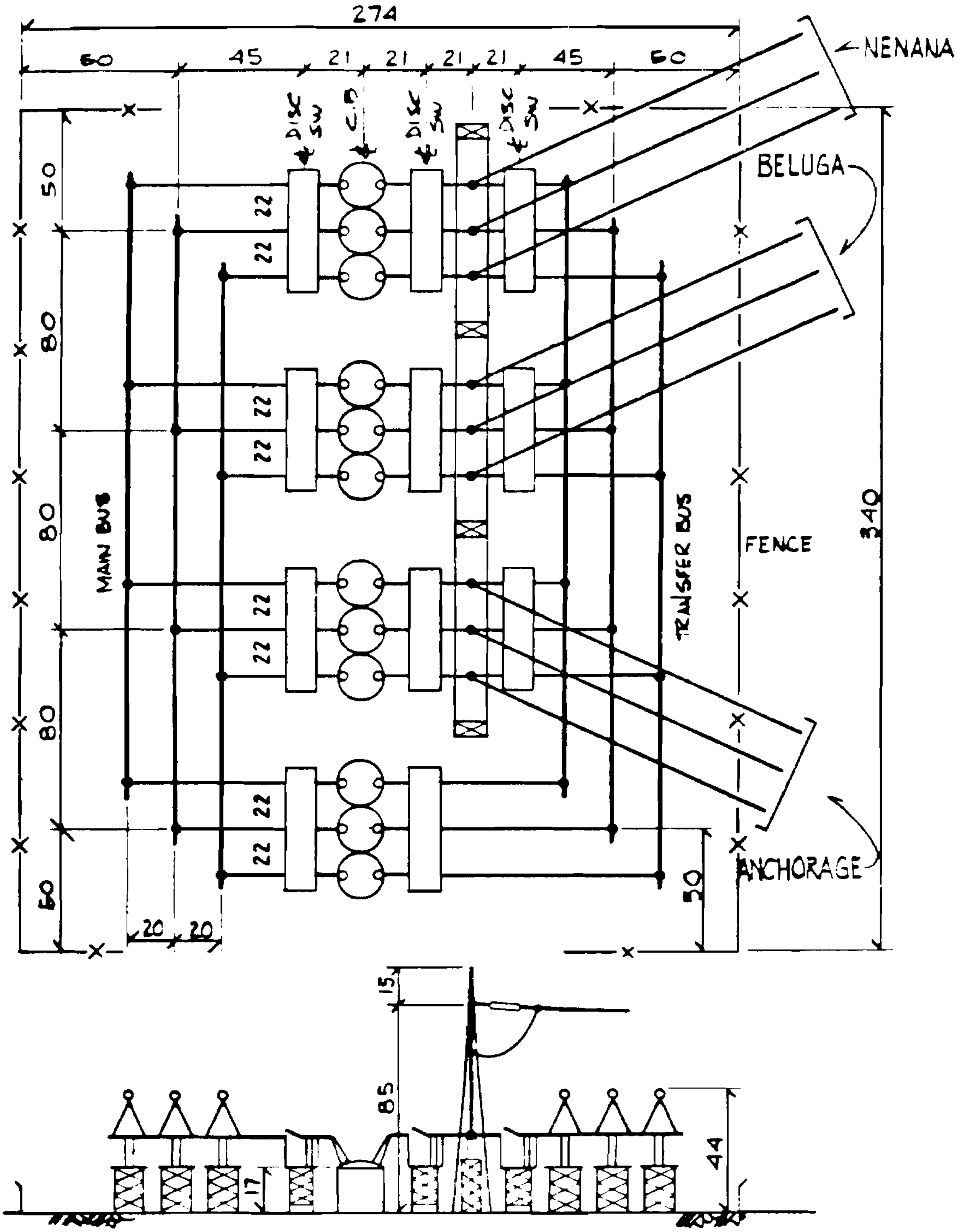


FIGURE 2.10. Willow Substation

determined after the system study is completed. The probability of future additional units at Beluga is a factor to be considered.

At present, there is an existing Chugach Electric combustion turbine plant near Beluga with approximately 300 MW of capacity. This plant's outlet voltage is 169 kV. Several lines connect this plant to Anchorage by an underwater crossing of the Knik Arm. This existing route was considered for the proposed Beluga coal plant output. However, in our estimation, the overhead tie line to Willow is more feasible than an underwater crossing. The inclusion of a 169-kV tie line between the existing combustion turbine plant and the proposed fossil plant will add flexibility. The turbine plant switchyard will need modification to add this line. The startup power required for the Beluga fossil plant could then be drawn from the combustion turbine plant or the tie line from Willow. The fossil plant switchyard voltage of 169 kV was selected based on this arrangement.

With this configuration, the output of the Beluga fossil plant can then be transmitted from Willow to either Anchorage or Fairbanks.

Presently, there is a 110-kV line in operation from Anchorage (Mackenzie) to Willow. It appears that large blocks of power will be transmitted over this tie; for this reason, replacement of this line by a 345-kV tie would enhance the North-South overall transmission system. This line is approximately 52 miles long and its inclusion would mean construction of a 345-kV substation or terminal at Mackenzie.

As previously stated, the above proposed tie line arrangement is offered without the benefit of the system study necessary to give a firm base to this proposed arrangement. Load flow estimates are necessary to determine the transfer capability, I^2R losses and reactive power requirements.

The previously cited study indicated a 9 percent loss if 70 MW was transmitted on the tie line at 345 kV using 2-1272 KCMIL ASCR conductors per phase. Towers were based on a 1200-ft span.

The major pieces of equipment at the Willow Substation will be as follows:

- 345-kV Main and Transfer Buses

- Four bays each consisting of one 345-kV circuit breaker and three 345-KV disconnect switches.

The transmission line system will also require the following:

- The addition of a 169-kV bay at the existing Beluga combustion turbine plant
- A tie line at 169 kV from the existing Chugach Electric Beluga combustion turbine plant to the Beluga coal-fired plant, a distance of approximately 50 miles
- The addition of a 345-kV terminal at Mackenzie
- A tie line at 345 kV from Willow to Mackenzie, a distance of 52 miles
- A tie line at 345 kV from Willow to Nenana, a distance of 160 miles
- Rerouting of the existing 138-kV line from Healy to Fairbanks into the Nenana switchyard.

2.4 SITE SERVICES

The construction and operation of a 200-MW coal-fired power plant will require a number of related services to support all work activities at the site. These site services could include the following, depending upon the actual location of the power plant:

- Access Roads
- Construction Water Supply
- Construction Transmission Lines
- Airstrip
- Railroad Spur (Nenana site)
- Landing Facility (Beluga site)
- 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 for the Beluga site and with the Anchorage-Fairbanks Highway (Route 3) for the Nenana site. For both locations it has been assumed that approximately 20 miles of access road will be required.

2.4.2 Construction Water Supply

A complete water supply, storage and distribution system will be installed. Due to the remote nature of either general location, a one-million gallon water storage tank has been assumed, with one-half of this storage capacity dedicated to fire protection purposes. Water supply to the project site should be by means of a 150 gpm well(s).

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 system. At a potential Beluga field site 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. For the Nenana area site, the 25-kV transmission line system is assumed to be derived from the existing Healy-Fairbanks intertie and be approximately 20 miles in length.

2.4.4 Airstrip

For either general power plant location, a 4,000-foot-long, 60-foot-wide gravel airstrip will be provided. It is anticipated that all personnel travel will be by air with pre-arranged 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 the size of a DC-3.

The airstrip will be lighted using an above-ground distribution system to provide for the possibility of night-time medical emergency traffic. No control tower will be required. All air traffic will be on a Visual Flight Rule (VFR) basis only.

2.4.5 Railroad Spur

A railroad spur will be constructed at the Nenana field site due to the proximity of the Alaskan railroad. The spur will be utilized to receive fuel from the mine, operating supplies and equipment shipments received in Anchorage. The length of this spur has been conservatively estimated to be approximately 20 miles.

2.4.6 Landing Facility

The Beluga field site will require construction of a marine landing facility to receive all construction materials, equipment and supplies. The landing facility would be located on Cook Inlet and be suitably dredged to accommodate military-type landing craft for delivery of goods. A paved, fenced interim storage area will be provided. A heavy-duty haulage road will be provided from the landing area to the access road.

2.4.7 Construction Camp Facilities

A 500-bed labor camp will be provided. The camp layout is presented in the plot plan (Figure 2.3). 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 job site on single status only, a mobile-home park will be provided for 16 supervisory personnel in family status. These mobile homes will be approximately 1000 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 200-MW station will vary over the approximate 4-1/2 year construction period. The distribution of this work force over the construction period is shown in Figure 2.11. Construction is estimated to peak in year 2, requiring a workforce of approximately 500 personnel.

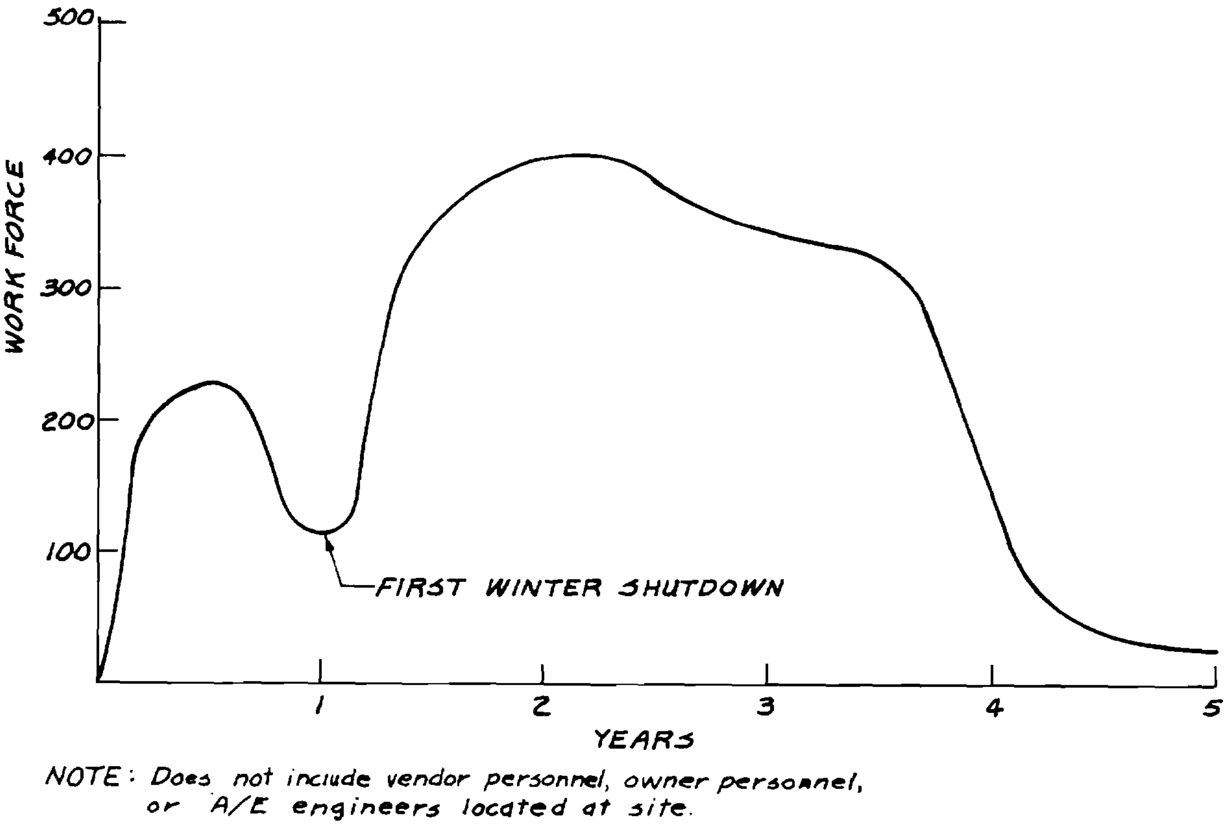


FIGURE 2.11. Construction Workforce Requirements

Construction of this 200-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.

2) Temporary construction office facilities (with heating and ventilation furnished by contractors as required)

3) Temporary and permanent access roads, railroad spur (for Nenana Station) and marine landing facility (Beluga Station)

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 compliance with OSHA regulations.

Following completion of these initial construction site related 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 2.12.

2.6 OPERATION AND MAINTENANCE

When the coal-fired steam-electric power plant begins commercial operation, the facility will provide employment for approximately 109 employees. Of this total approximately 67 will represent operating staff, while 42 will be maintenance personnel. An estimate of the plant's staffing requirements is presented in Table 2.2. Employment of these personnel will continue throughout the 35-year 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 radio-telephone communication system. For both station locations, two diesel generators of approximately 1,500 kW capacity will be required to provide enough power for startup and safe shutdown of the units under trip and black-out conditions.

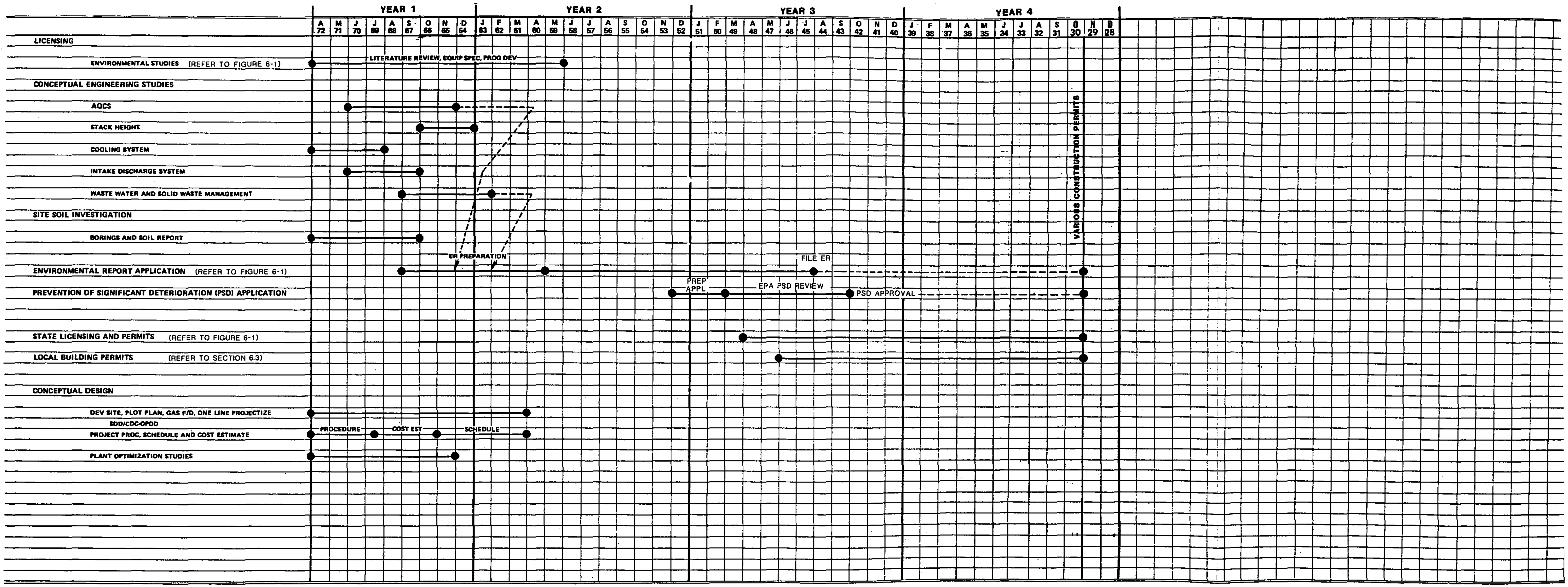


FIGURE 2.12. Project Schedule

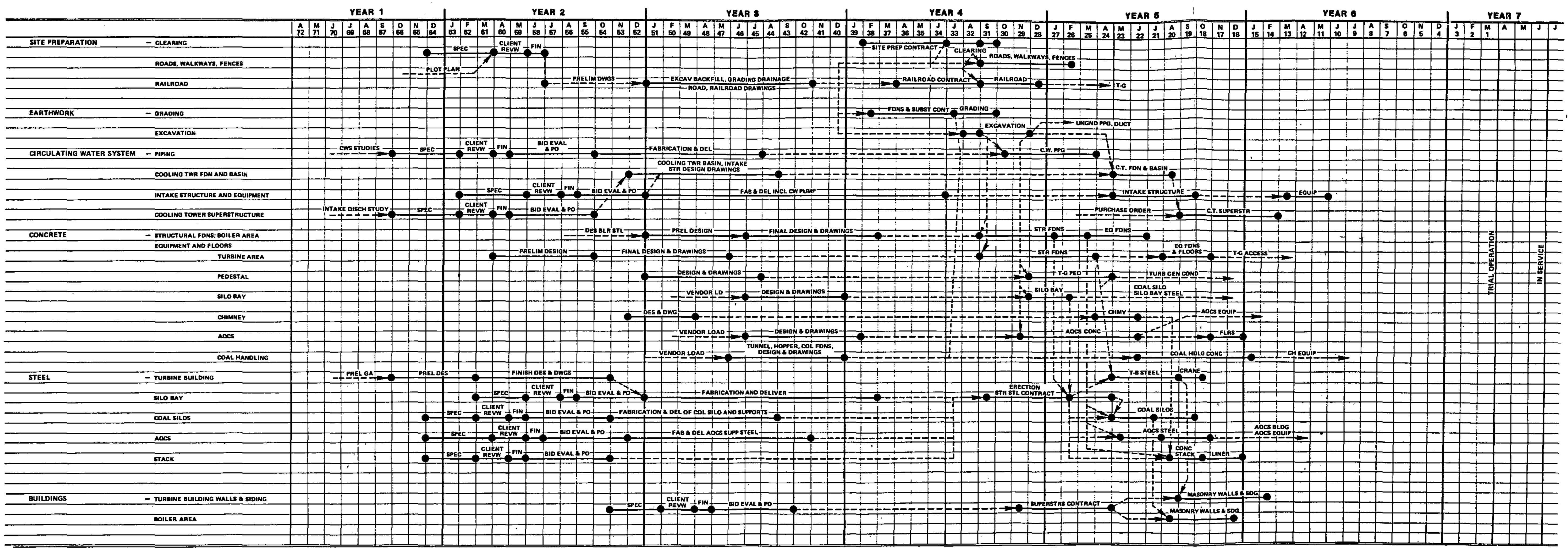


FIGURE 2.12. (contd)

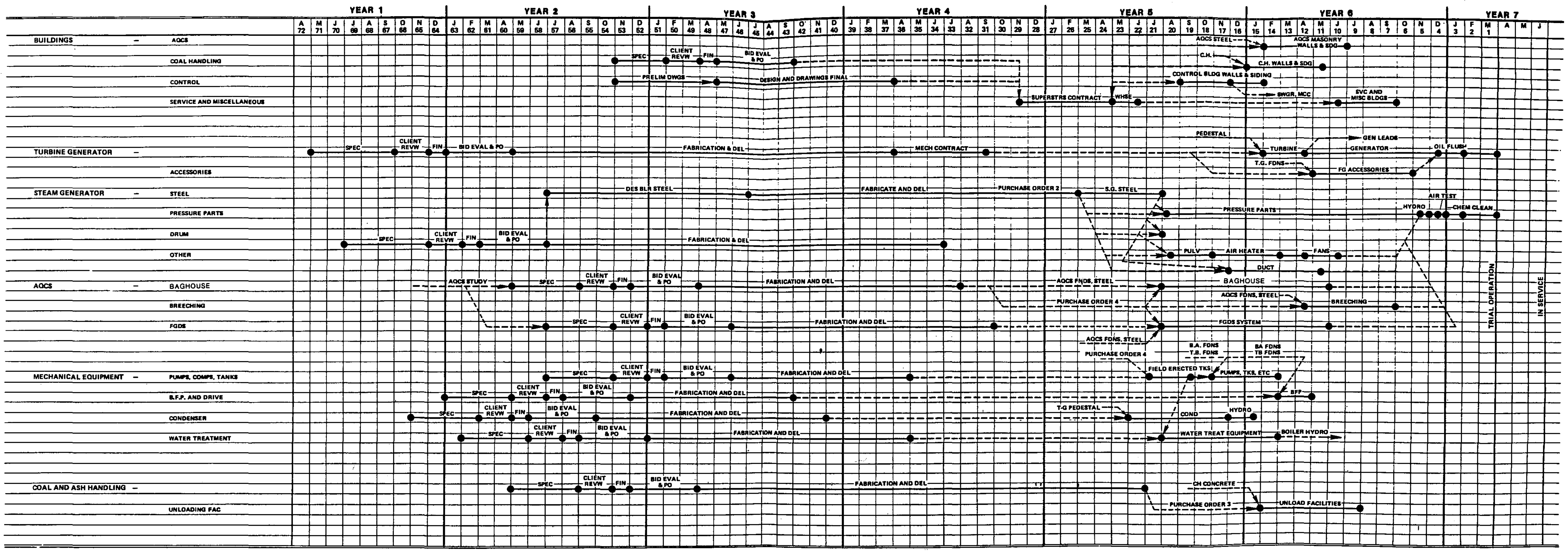


FIGURE 2.12. (contd)

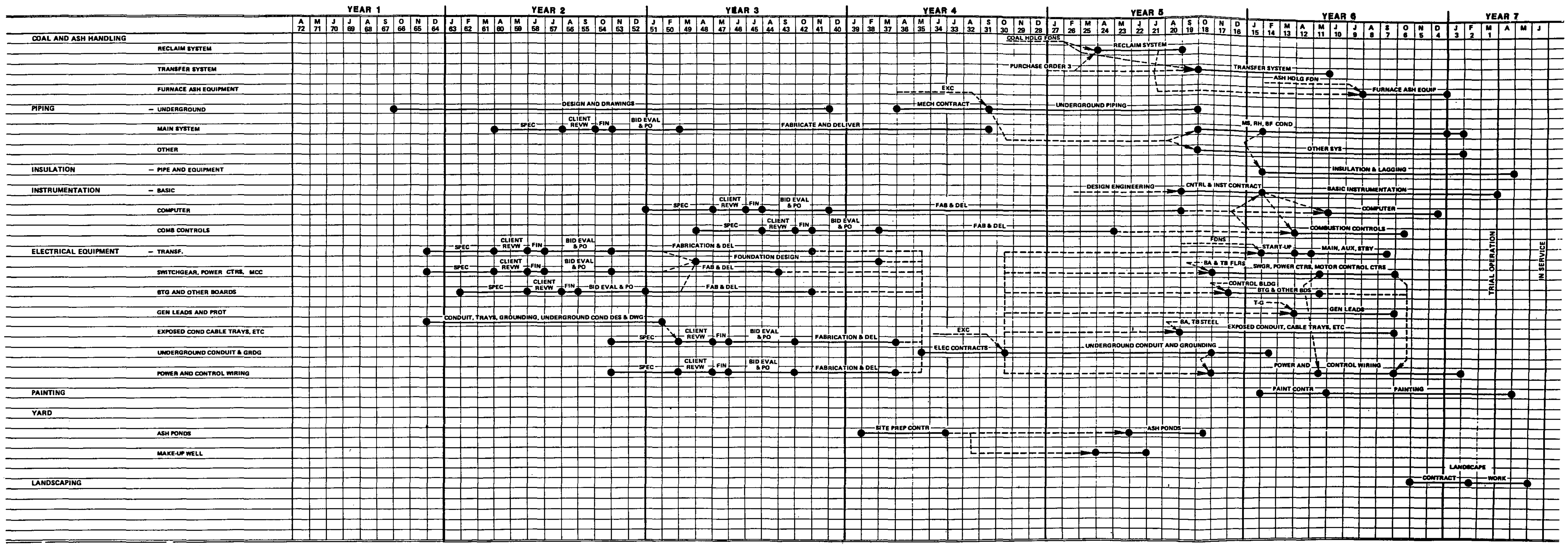


FIGURE 2.12. (contd)

TABLE 2.2. Plant Staffing Requirements

Job Title	Staff Required
Plant Superintendent	1
Operations Engineer	1
Shift Superintendent	4
Control Room Operators and Auxiliary Operators	8
Chemist	1
Chemical Technician	1
Results Engineer	1
Results Technician	1
I&C Engineer	1
I&C Technician	4
Storekeeper	1
Storekeeper Help	1
Clerical	3
Maintenance Superintendent	1
Maintenance Engineer	1
Maintenance Foreman (Elec/Mech)	2
Mechanics (6-Man Crews)	12
Maintenance Foreman (I&C)	1
Mechanics (6-Man Crews)	6
Labor Foreman	2
Labor Crew	8
Fire Protection/Security	4
Coal-Yard Crew & Ash Disposal	
Foreman	3
Caterpillar Operator	4
Breaker House	3
Equipment Maintenance	1
Caterpillar-Truck Operators	3
Bottom & Fly Ash	4
Permanent Ash Disposal Site	3
Scrubber	
Auxiliary Operators	12
Equipment Operator	3
Mechanics	8
Total	109

NOTE: The above staffing is required for three 8-hour shifts and seven-days-a-week operation.

To prevent mechanical failure, periodic maintenance will be performed on all pressure systems, rotating machinery, heat sensitive equipment, and other operating equipment for malfunctions, leaks, corrosion and other such abnormalities. In addition, the maintenance programs will monitor the revegetation and erosion prevention programs 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 annual scheduled outages. The length of time required for these scheduled outages is estimated to be approximately 675 hours per year for plants ranging in size from 100 MW to 300 MW. This value corresponds to a scheduled outage rate[a] of 8 percent.

The power plant will also experience periods of forced outage, defined as the occurrence of a component failure or other condition that requires the unit be removed from service. Estimates of forced outage hours and forced outage rates[b] for various-size units are presented below:

Unit Size	Forced Outage Hours (hours/year)	Forced Outage Rate (percent)
150	390	4.8
200	460	5.7
250	535	6.6

If properly maintained, power plants in the size range of 150 MW to 250 MW should be able to experience heat rates of approximately 10,000 Btu/kWh over their entire plant life.

(a) $\text{Scheduled Outage Rate} = \frac{\text{Scheduled Outage Hours}}{\text{Service Hours + Scheduled Outage Hours}} \times 100$

(b) $\text{Forced Outage Rate} = \frac{\text{Forced Outage Hours}}{\text{Service Hours + Forced Outage Hours}} \times 100$

3.0 COST ESTIMATES

3.1 CAPITAL COSTS

3.1.1 Construction Costs

Construction costs have been developed for the major bid line items common to coal-fired power plants. These line item costs have been broken down into the following categories: labor and insurance, construction supplies, equipment repair labor, equipment rental, permanent materials, and subcontracts. Results of this analysis are presented in Table 3.1 for the Beluga Station and in Table 3.2 for the Nenana Station.

Equivalent unit capital costs are as follows:

Beluga Station	2050 $/kW
Nenana Station	2110 $/kW

3.1.2 Payout Schedule

Payout schedules have been developed for the entire project. Table 3.3 contains monthly payouts for the Beluga project, and Table 3.4 contains monthly payouts for the Nenana project. Payout schedules for both projects were based on a 48-month basis from start of project to completion.

Equivalent annual payouts are as follows:

Year	Beluga Station		Nenana Station	
	$	%	$	%
1	72,006,000	17.6	76,720,600	18.2
2	119,372,000	29.1	121,283,000	28.8
3	121,096,600	29.5	126,740,600	30.1
4	97,687,500	23.8	96,622,200	22.9

TABLE 3.1. Bid Line Item Costs for Beluga Area Station[a] (January 1982 Dollars)

		Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1.	Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2.	Earthwork and Piling	2,541,000	3,888,000		5,706,000	16,000		12,151,000
3.	Circulating Water System	2,511,000	174,200		2,391,000	1,235,000	10,000,000	16,311,200
4.	Concrete	5,733,000	540,000		1,091,000	2,387,000		9,751,000
5.	Struct, Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6.	Buildings	682,000				800,000		1,482,000
7.	Turbine-Generator	1,800,000				19,500,000		21,300,000
8.	Steam Generator and Accessories	15,764,000				21,800,000		37,564,000
9.	Air Quality Control System	12,400,000				27,100,000		39,500,000
10.	Other Mechanical Equipment					8,950,000		8,950,000
11.	Coal and Ash Handling	576,000				1,500,000	5,000,000	7,076,000
12.	Piping	14,435,000				9,000,000		23,435,000
13.	Insulation and Lagging						1,500,000	1,500,000
14.	Instrumentation						3,000,000	3,000,000
15.	Electrical Equipment	1,000,000					30,000,000	31,000,000
16.	Painting	1,015,000				1,100,000		2,115,000
17.	Off-Site Facilities						3,000,000	3,000,000
18.	Waterfront Construction						600,000	600,000
19.	Substation	1,275,000	22,000		92,000	2,686,000		4,075,000
20.	Indirect Construction Cost and Architect/Engineer Services[b]	44,515,000	50,907,000	2,562,000	2,084,000	9,000		100,077,000
	Subtotal	$106,354,000	$55,533,300	$2,562,000	$12,265,000	$103,348,000	$53,100,000	$333,162,300
	Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
	Contingencies							47,000,000
	TOTAL PROJECT COST							$410,162,300

(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 $39,229,000 for construction camp, $31,300,000 for engineering services, and $29,548,000 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. Bid Line Item Costs for Nenana Area Station[a] (January 1982 Dollars)

		Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1.	Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2.	Earthwork and Piling	2,100,000	13,000		5,400,000	16,000		7,529,000
3.	Circulating Water System	2,561,000	174,200		2,391,000	1,235,000	11,500,000	17,861,200
4.	Concrete	5,982,000	540,000		1,091,000	2,387,000		10,000,000
5.	Struct, Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6.	Buildings	682,000				800,000		1,482,000
7.	Turbine-Generator	1,800,000				19,500,000		21,300,000
8.	Steam Generator and Accessories	15,662,000	138,000		12,000	21,800,000		37,612,000
9.	Air Quality Control System	12,400,000				27,100,000		39,500,000
10.	Other Mechanical Equipment					8,950,000		8,950,000
11.	Coal and Ash Handling	1,937,000	18,000		150,000	5,785,000		7,890,000
12.	Piping	14,435,000				9,000,000		23,435,000
13.	Insulation and Lagging	441,000	46,000		11,000	1,049,000		1,547,000
14.	Instrumentation					3,000,000		3,000,000
15.	Electrical Equipment	12,720,000	1,150,000		800,000	18,000,000		32,670,000
16.	Painting	1,142,000	58,000		25,000	575,000		1,800,000
17.	Off-Site Facilities	4,827,000			3,600,000	3,260,000		11,687,000
18.	Waterfront Construction							N/A
19.	Substation - Switchyard	1,623,000	34,000		143,000	3,017,000		4,817,000
20.	Indirect Construction Cost and Architect/Engineer Services[b]	54,943,000	42,560,000	2,882,000	2,617,000	9,000		103,011,000
	Subtotal	$135,362,000	$44,733,300	$2,882,000	$17,141,000	$132,748,000	$11,500,000	$344,366,300
	Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
	Contingencies							47,000,000
	TOTAL PROJECT COST							$421,366,300

N/A = Not Applicable.
(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 $40,816,000 for construction camp, $31,300,000 for engineering services, and $30,895,000 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

TABLE 3.3. Payout Schedule for Beluga Area Station (January 1982 Dollars)

Month	Cost per Month, Dollars	Cumulative Cost, Dollars
1	789,400	789,400
2	7,310,700	8,100,100
3	7,287,500	15,387,600
4	7,287,500	22,675,100
5	6,831,700	29,506,800
6	8,762,700	38,269,500
7	7,413,500	45,683,000
8	7,539,700	53,222,700
9	7,364,100	60,685,800
10	7,285,600	67,971,400
11	2,017,300	69,988,700
12	2,017,300	72,006,000
13	2,017,300	74,023,300
14	7,154,500	81,177,800
15	8,676,200	89,854,000
16	10,489,800	100,343,800
17	10,489,800	110,833,600
18	10,541,600	121,375,200
19	10,914,500	132,289,700
20	10,914,500	143,204,200
21	10,914,500	154,118,700
22	10,914,500	165,033,200
23	13,031,200	178,064,400
24	13,313,900	191,378,300
25	10,830,900	202,209,200
26	10,458,000	212,667,200
27	10,458,000	223,125,200
28	10,458,000	233,583,200
29	10,458,000	244,041,200
30	10,458,000	254,499,200
31	10,458,000	264,957,200
32	10,458,000	275,415,200
33	10,406,200	285,821,400
34	8,884,500	294,705,900
35	8,884,500	303,590,400
36	8,884,500	312,474,900
37	8,660,200	321,135,100
38	8,985,600	330,120,700
39	8,985,600	339,106,300
40	8,985,600	348,091,900
41	8,985,600	357,077,500
42	8,985,600	366,063,100
43	8,985,600	375,504,870
44	8,985,600	384,034,300
45	8,985,600	393,019,900
46	8,985,600	402,005,500
47	3,963,400	405,968,900
48	4,193,500	410,162,400

TABLE 3.4. Payout Schedule for Nenana Area Station (January 1982 Dollars)

Month	Cost per Month, Dollars	Cumulative Cost, Dollars
1	754,800	754,800
2	7,552,800	8,307,600
3	7,529,300	15,837,900
4	7,529,300	23,366,200
5	7,078,000	30,444,200
6	9,104,500	39,548,700
7	7,768,100	47,316,800
8	7,894,900	55,211,700
9	7,818,200	63,029,900
10	7,640,700	70,670,600
11	3,025,000	73,695,600
12	3,025,000	76,720,600
13	3,025,000	79,745,600
14	7,880,300	87,625,900
15	8,731,100	96,357,000
16	10,521,900	106,878,900
17	10,521,900	117,400,800
18	10,573,200	127,974,000
19	10,942,400	138,916,400
20	10,942,400	149,858,800
21	10,942,400	160,801,200
22	10,942,400	171,743,600
23	12,988,000	184,731,600
24	13,272,000	198,003,600
25	11,633,900	209,637,500
26	11,264,700	220,902,200
27	11,264,700	232,166,900
28	11,264,700	243,431,600
29	11,264,700	254,696,300
30	11,264,700	265,961,000
31	10,725,800	276,686,800
32	10,725,800	287,412,600
33	10,674,500	298,087,100
34	8,885,700	306,972,800
35	8,885,700	315,858,500
36	8,885,700	324,744,200
37	8,665,200	333,409,400
38	8,948,800	342,358,200
39	8,948,800	351,307,000
40	8,948,800	360,255,800
41	8,794,100	369,049,900
42	8,794,100	377,844,000
43	8,794,100	386,638,100
44	8,794,100	395,432,200
45	8,794,100	404,226,300
46	8,794,100	413,020,400
47	4,057,700	417,078,100
48	4,288,300	421,366,400

3.1.3 Escalation

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

3.1.4 Economics of Scale

In the range of the considered plant sizes (150 MW through 250 MW) there is a negligible difference in construction costs per kilowatt hour of generation. No significant cost-related economies of scale can be found in this range of plant sizes.

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 "Alaskan" dollars, are as follows:

Fixed Costs

Staff (109 Persons)	$3,342,700/yr ($16.70/kW-yr)

Variable Costs

Operating Supplies and Expenses	$ 315,000/yr[a] (0.2 mills/kWh)
Maintenance Supplies and Expenses	$ 597,100/yr[a] (0.4 mills/kWh)

3.2.2 Escalation

Estimated real escalation of fixed and variable operation and maintenance costs[b] 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 - on	2.0

(a) @ 85% capacity factor.
(b) Escalation series used by Ebasco for project cost estimating.

3.2.3 Economics of Scale

In the range of considered plant sizes (150 MW through 250 MW) there is a negligible difference in operation and maintenance costs per kilowatt hour of generation. No cost-related economies of scale can be found in this range of plant sizes.

3.3 FUEL AND FUEL TRANSPORTATION COSTS

Estimated prices for Beluga and Nenana coal are developed in the report Alaska Coal: Future Availability and Price Forecasts (Swift 1981), produced in conjunction with this study.

3.3.1 Nenana Station

Coal for the proposed Nenana Station would be supplied from the Usibelli Coal Mine, Inc. via the Alaska Railroad, probably by a unit train operation. Future coal prices were estimated based on estimates of base coal prices, FOB Healy, plus tentative ARR unit train rates. Real escalation was based on estimated real increases in minemouth coal costs as well as railroad diesel fuel costs. The resulting time series of delivered prices is shown in Table 3.5.

3.3.2 Beluga Station

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 minemouth price stream is shown in Table 3.5. This analysis, of course, presumes development of an export Pacific Rim market.

3.4 COST OF POWER

Estimated busbar power costs from the proposed Beluga and Nenana Stations are shown in Figure 3.1. Costs shown are levelized lifetime busbar power

TABLE 3.5. Estimated Coal Prices: Beluga and Nenana Stations (January 1982 $) (Swift 1981)

Year	Nenana Coal FOB Healy[(a)] ($/MMBtu)	Nenana Coal FOB Nenana[(b)] ($/MMBtu)	Beluga Coal Mine Mouth[(c)] ($/MMBtu)
1980	1.43	1.75	--
1981	1.46	1.78	--
1982	1.49	1.81	--
1983	1.52	1.84	--
1984	1.55	1.88	--
1985	1.58	1.91	--
1986	1.61	1.94	--
1987	1.64	1.98	--
1988	1.68	2.01	1.69
1989	1.71	2.05	1.72
1990	1.74	2.09	1.76
1991	1.78	2.12	1.80
1992	1.81	2.16	1.83
1993	1.85	2.20	1.87
1994	1.89	2.24	1.91
1995	1.92	2.28	1.95
1996	1.96	2.32	1.99
1997	2.00	2.36	2.03
1998	2.04	2.41	2.08
1999	2.08	2.45	2.12
2000	2.12	2.49	2.16
2001	2.16	2.54	2.21
2002	2.21	2.58	2.26
2003	2.25	2.63	2.30
2004	2.29	2.68	2.35
2005	2.34	2.73	2.40
2006	2.39	2.77	2.45
2007	2.44	2.82	2.50
2008	2.48	2.88	2.55
2009	2.53	2.93	2.61
2010	2.58	2.98	2.66

(a) 2% annual escalation rate from 1980 base price.
(b) 1.8% annual escalation rate from 1980 base price.
(c) 2.1% annual escalation rate from 1980 base price.

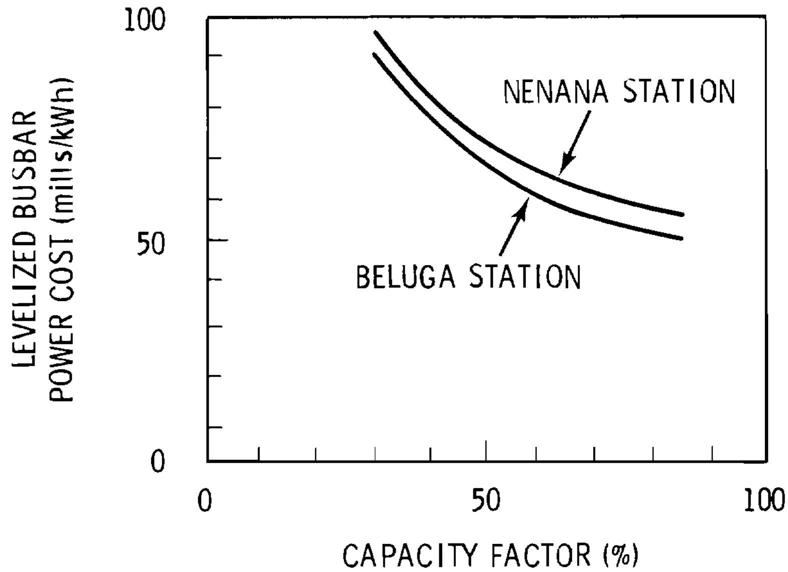


FIGURE 3.1. Cost of Power Versus Capacity Factor (January 1982 dollars)

costs, expressed in January 1982 dollars. The costs are based on the following financial parameters:

Debt Financing	100%
Equity Financing	0%
Interest on Debt	3%
Federal Taxes	None
State Taxes	None
Year of First Commercial Operation	1990
Bond Life	30 years
General Inflation	0%

The escalation factors shown in this report were employed. Weighted average capital cost escalation factors were derived using a labor/material ratio of 44%/56%.

Levelized lifetime power costs for the plant will rise over time because of the forecasted continuing escalation in capital, O&M and fuel costs. Estimated levelized busbar power costs for the two stations, expressed as a function of the first year of commercial operation and assuming an 85% plant capacity factor, are shown in Figure 3.2. These costs are expressed in January 1982 dollars.

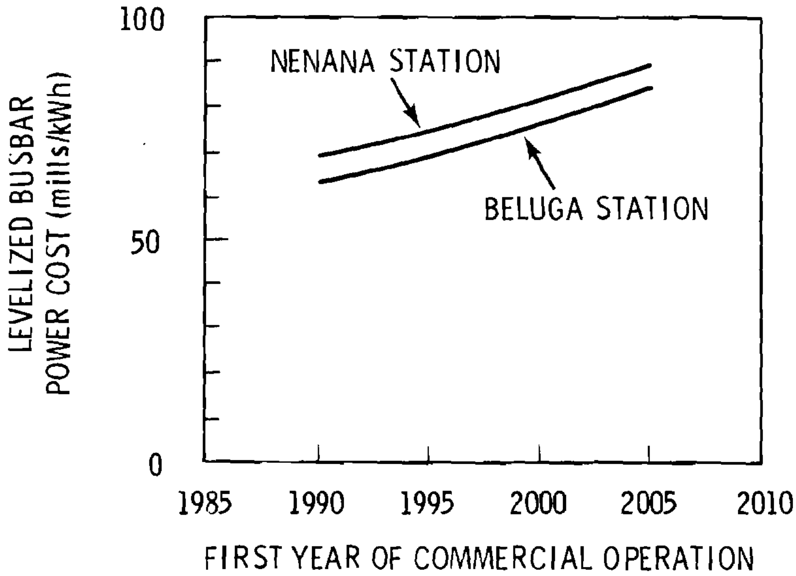


FIGURE 3.2. Cost of Power Versus First Year of Commercial Operation (January 1982 dollars)

4.0 ENVIRONMENTAL AND ENGINEERING SITING CONSTRAINTS

An environmental impact statement will likely be required for construction and operation of a 200-MW coal-fired power plant at either the Beluga or Nenana sites (see Section 6.1.5). Council of Environmental Quality regulations implemented pursuant to the National Environmental Policy Act of 1969 require that an environmental impact statement include a discussion and evaluation of alternative site locations. This requirement is usually satisfied through the performance of a site evaluation study. The purpose of such a study is to identify a preferred site location(s) and possibly viable alternative locations for the construction and operation of the generating station.

The following subsections present many of the constraints that would be evaluated during a siting study, with special attention given to their applicability to the two locations considered in this study. It should be realized that many of the constraints placed upon the development of a coal-fired power plant are regulatory in nature and therefore the discussion presented in this section is complemented by the identification of power plant licensing requirements presented in Section 6.0.

4.1 ENVIRONMENTAL SITING CONSTRAINTS

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 operation. Siting and design analyses generally attempt to minimize flow reduction of potential water supply sources while maximizing plant reliability. For this reason, it is necessary to examine low flows as well as average annual and monthly flows. For the Nenana location, water availability should not represent a constraint that would deter development. The quantities of water required by the plant are an extremely small percentage (<1 percent) of the Nenana River's minimum recorded low flow. Special consideration will have to be given to intake structure location since freezing and ice-related problems may affect design and operational reliability. Consideration of stream morphology and geometry will also be important to avoid local flow reduction effects during low flow periods.

At the Beluga location, large river systems do not exist and therefore smaller streams will have to be analyzed to determine their suitability as a supply source. Potential groundwater supply 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 these alternatives could, however, significantly affect power plant costs. This cost increase would have to be evaluated in light of the potential impact of utilizing surface water resources.

Existing water quality can represent a significant siting constraint. First, receiving stream water quality standards if particularly stringent, could prohibit plant effluent discharge. Secondly, makeup water quality requirements may mandate the provision of an extensive water treatment facility if the quality of the water source is inferior. This consideration should not prove restrictive at either potential plant location. The water quality of the Nenana River and most other surface water resources is acceptable from a makeup water management viewpoint. However, if the Beluga plant utilizes a groundwater supply system, an extensive treatment system may be required since groundwater is generally highly mineralized.

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 6.0; however, the major factors that must be evaluated include:

- Proximity to Class I PSD areas.
- Proximity to non-attainment ambient air quality areas.
- General dispersion capability of the area.

These factors are evaluated through the use of a computerized mathematical model that develops estimates of atmospheric diffusion and the resulting concentration of various air quality parameters. Input to the model consists of the characteristic emissions ("source term") of the plant and local meteorological data.

Of the three factors listed above, the Denali National Park Class I area could pose the most severe siting constraint for the development of a coal-fired facility. 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 should be analyzed in detail to insure a proper evaluation. The Class I visibility regulations could significantly effect this minimum distance. The proposed Nenana location is approximately 40 miles north of the current park boundary.

In the Fairbanks and Anchorage areas, the levels of carbon monoxide (CO) exceed the primary National Ambient Air Quality Standards. The state regulatory agencies are required to reduce CO emissions in these two airsheds in order to attain the standards. This goal will be accomplished by requiring any new or modified major source to install the lowest achievable emission rate for CO emissions and to obtain offsets for the actual CO emissions. Consequently, the construction of a coal-fired power plant in or near these non-attainment areas will entail the most demanding pollution controls as well as a lengthy and detailed regulatory review. While these requirements will not preclude development, they will entail rigorous analyses during the plant siting process, especially for the Nenana location, which also poses a Class I area restriction.

4.1.3 Aquatic and Marine Ecology

Since the plant's makeup and discharge requirements are relatively small, entrainment and impingement impacts and wastewater discharge impacts will probably not be site-differentiating. The major activity in this area during the siting process, would, therefore, be identification of exclusion and avoidance areas to be considered in association with intake and discharge structure development. The delineation of these 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 and rare and/or endangered species and their critical habitats.

4.1.4 Terrestrial Ecology

Since habitat loss is generally considered to represent the most significant impact on wildlife, identification of important wildlife areas, especially critical habitat of threatened or endangered species, must be identified. Based upon this inventory, exclusion, avoidance and preference areas would be factored into the plant siting process. A number of important and sensitive species inhabit both potential site areas, including moose, caribou, brown and black bear, and Dall sheep.

4.1.5 Socioeconomic Constraints

Major socioeconomic constraints center about potential land use conflicts and community and regional socioeconomic impacts derived from project activities. Potential exclusionary land use conflicts would 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-fired installation might preclude or not be compatible with local activities (e.g., urban areas or Indian reservations), or those areas presenting safety considerations (e.g., aircraft facilities). Avoidance areas would generally include areas of proven archeological or historical importance not under legislative protection, and prime agricultural areas.

Minimization of the boom/bust cycle will also be a prime criterion. Through the application of criteria pertaining to community housing, population, infrastructure and labor force; preferred locations and mitigation measuring will be identified. Because the potential power plant sites are remote and will likely cause significant boom/bust impacts on nearby small communities, socioeconomic criteria would be heavily weighted in the overall site evaluation process.

4.2 ENGINEERING SITING CONSTRAINTS

The development of engineering criteria for use during the site evaluation process is necessary to minimize engineering and construction problems and, thereby, facility investment and operating costs. The development of either the Nenana or Beluga Station could be constrained by a number of factors bearing upon the engineering aspects of the project. These factors include site topography and geotechnical characteristics, access road distance, transmission line distance, and water supply distance.

4.2.1 Site Topography and Geotechnical Characteristics

In general, the power plant should be sited in relatively flat terrain. This will minimize the amount of grading and excavation, and 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 major streams.

Another major criterion is the avoidance of areas with poor soil conditions as these can cause significant construction and reliability problems due to poor suitability as a foundation for structures. Soil-related foundation problems can be expected in the Beluga area due to the presence of highly organic soil (muskeg) that will probably require extensive piling to be placed under major structures and equipment foundations. In the Nenana area, a site free of permafrost must be selected.

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, the potential locations fall within regions of high seismic activity (Zone 3). While this will not preclude development nor differentiate between the sites, it will increase construction costs as more material will be required to insure plant foundation and disposal area dike stability.

A final geotechnical-related criterion concerns the availability of borrow material. Sites that contain an adequate supply of borrow material can be far less costly, especially if alternate sites must haul in this material over long distances.

4.2.2 Access Road, Railroad and Transmission Line Considerations

Siting a power plant in close proximity to existing roads, rail service and transmission lines minimizes the cost associated with extension of these facilities and also minimizes the environmental effects associated with land disturbance. From an economic point of view, access roads, railroad spurs and transmission interties should be limited to a maximum distance of approximately 20 miles in flat terrain and 10 miles in rough terrain. The allowance for roads and railroad spurs should be sufficient to insure compliance with established safety and reliability standards, for example, the maximum allowable grades (approximately 1.5 percent and 6 percent for railroads and roads, respectively). Route selection will also be affected by soil and meteorological conditions. Permafrost, potential frost heave problems and other soil-related characteristics can significantly add to the cost of road facilities, and 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 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, 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., duplicate pipeline), and the need to minimize operating costs associated with water pumping.

5.0 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

5.1 SUMMARY OF FIRST ORDER ENVIRONMENTAL IMPACTS

The construction and operation of a 200-MW coal-fired steam-electric generating facility will create changes or impacts to the land, water, air and socioeconomic environments in which it is located. These impacts are directly related to the primary effects of the plant on the environment. A summary of these effects is presented in Table 5.1. These primary effects are analyzed and evaluated in light of existing environmental conditions to determine the significance of the impact and the need for mitigative measures.

5.2 ENVIRONMENTAL AND SOCIOECONOMIC EFFECTS

5.2.1 Water Resource Effects

The design of the proposed stations minimizes adverse water resource impacts by incorporating "dry" solid waste disposal facilities and a wet/dry cooling tower system. These components result in small makeup water requirements and minimal wastewater discharges. Significant, difficult-to-mitigate impacts are therefore not anticipated.

5.2.2 Air Resource Effects

The power plant will be required to meet the Best Available Control Technology (BACT) for atmospheric emissions, which is at least as stringent as the New Source Performance Standards (NSPS). In addition, the national emission standards for hazardous air pollutants must be met. Finally, the plant must demonstrate that applicable state and federal atmospheric ambient air quality criteria and prevention of significant deterioration (PSD) increments will not be exceeded. To demonstrate compliance with these regulations, a 1-year onsite air quality and meteorology monitoring program must be carried out. In light of these regulatory restrictions, significant, difficult-to-mitigate air resource impacts are not expected.

Increasing concern has been expressed regarding the long-term effects of the CO_2 production of combustion-based power plants. Of particular concern is the potential "greenhouse" effect of increased atmospheric CO_2 concentration.

TABLE 5.1. Primary Environmental Effects

Air	
Particulate Emissions	60.4 lb/hr (0.03 lb/10^6 Btu)
Sulfur Dioxide Emissions	377 lb/hr (<0.6 lb/10^6 Btu)[(a)]
Nitrogen Oxide Emissions	1207 lb/hr (0.60 lb./10^6 Btu)
Water	
Plant Water Requirements	1947 gpm (Wet Cooling)
	287 gpm (Dry Cooling)
Plant Water Discharge	
Process Water	None
Coal Pile Runoff	Infrequent (<4 events/35 yr. life)
Land	
Land Requirements	
Plant Island	25 acres
Solid Waste Disposal Site	50 acres
Socioeconomic	
Construction Workforce	500 personnel
Operating Workforce	109 personnel

(a) Assumes 70% reduction.

Because the source of carbon for a coal-fired plant is a fossil fuel, the plant would contribute to the buildup of atmospheric CO_2. No regulations controlling production of CO_2 currently exist.

5.2.3 Aquatic and Marine Ecosystem Effects

Relatively small power plant water requirements and infrequent wastewater discharges will minimize the potential for adverse aquatic ecosystem impacts.

Assuming that the intake and discharge structures are properly designed and located, significant, difficult-to-mitigate impacts should not occur.

5.2.4 Terrestrial Ecosystem Effects

The greatest impact on the terrestrial biota resulting from the development of the proposed plants will be the loss or alteration of habitat. Both potential power plant locations contain seasonal ranges of moose and caribou. In addition, the Nenana location is within the range of brown bear. While the plant's total land requirements are modest, approximately 75 acres, disturbance of these range areas will lower the carrying capacity of the land to support these species. This could represent a significant terrestrial ecosystem impact, depending upon the plant's specific location. Wildlife impacts, however, can be minimized by siting the plant outside of important wildlife areas.

5.2.5 Socioeconomic Effects

Most of the communities located near both the Beluga and Nenana locations are generally small in population and have an infrastructure that is not highly developed. In light of this, the construction and operation of a 200-MW coal-fired plant has a high potential to impact local communities and cause a boom/bust cycle. This impact will be most significant in the Beluga region where 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.

If the Nenana site is located within an approximate 50-mile radius of Fairbanks, a boom due to construction will be a less likely event, since many of the 500 construction personnel could commute to the site from Fairbanks. The impact of project construction would also be mitigated by the sizeable Fairbanks labor market and high unemployment rate. A site located further than 50 miles from Fairbanks would, however, create impacts similar to those anticipated at a Beluga location.

6.0 INSTITUTIONAL CONSIDERATIONS

This section presents an inventory of major federal, State of Alaska, and local environmental regulatory requirements that would be associated with the development of either the Beluga Station or the Nenana Station. The inventory is divided into three subsections, setting forth federal, state, and local environmental licensing requirements. A list of these requirements is presented in Table 6.1. The discussion of the environmental study requirements associated with environmental report preparation under the National Environmental Policy Act of 1969 is included in Subsection 6.1.

6.1 FEDERAL REQUIREMENTS

6.1.1 Air

Air pollution controls are placed on new coal-fired power plants through the provisions of the Clean Air Act (CAA). The CAA is implemented primarily through permitting programs that would ensure compliance with national ambient air quality standards (NAAQS) and that would prevent significant deterioration in areas where NAAQS are being met. Through a permit, a power plant is required to restrict emissions in accordance with new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), and visibility protection requirements.

The permitting program and controls to which a power plant will be subject are largely dependent upon its location. As the two proposed plant locations are situated in areas in which air pollution levels are in compliance with NAAQS, the plant will be subject to the prevention of significant deterioration (PSD) permitting program administered by EPA in accordance with CAA Sections 160-169. Currently, EPA retains authority to issue this PSD permit in the state of Alaska, although the state is now in the process of developing its own PSD permitting program which, when finalized, will transfer to the state this permitting authority. Until that time, EPA will continue to issue these permits based on rules found at 40 CFR 32.21.

Under these rules, major sources of pollution cannot begin construction until a PSD permit has been issued. A power plant is considered a "major

TABLE 6.1. Permits, Approvals, and Certifications Required for a Coal-Fired Power Plant in Alaska

Agency	Name	Scope	Statute or Authority
U.S. Environmental Protection Agency	National Pollutant Discharge Elimination	Discharges to Water	33 USC 1251 et. seq., Section 1342
U.S. Army Corps Of Engineers	Construction Activity in Navigable Water	Construction in Water	33 USC 401 et. seq., Section 403
	Discharge of Dredged Fill Material	Discharges to Water	33 USC 1251 et. seq., Section 1342
Alaska Department of Environmental Conservation	State Certification that Discharges comply with CWA and State Water Quality Requirements	Discharges to Water	33 USC 1251 et. seq., Section 1341
Alaska Department of Natural Resources	Water Rights Permit	Appropriation of Water	Alaska Statute 46.15.030-185
U.S. Environmental Protection Agency	Prevention of Significant Deterioration Permit	Air Emissions	42 USC 7401 et. seq., Section 7475
Alaska Department of Environmental Conservation	Air Quality Control Permit to Operate	Air Emissions	Alaska Statute 46.03.140
U.S. Environmental Protection Agency	Hazardous Waste Management Facility Operation	Hazardous Waste	42 USC 6901 et. seq., Section 6925
Alaska Department of Environmental Conservation	Solid Waste Management Facility Operation	Solid Waste	Alaska Statute 46.03.100
Alaska Office of the Governor	Coastal Use Permit	Land Use	Alaska Statute 46.40
Federal Aviation Administration	Air Navigation Approval	Air Space	49 USC 1304, 1348, 1354,1431,1501

TABLE 6.1. (contd)

Agency	Name	Scope	Statute or Authority
National Marine Fisheries Service/Fish & Wildlife Service	Threatened or Endangered Species Review	Air, Water, Land	16 USC 1531 et. seq.
Advisory Council on Historic Preservation	Determination that Site Does Not Infringe On Federal Landmarks	Land Use	16 USC 461 et. seq.
	Determination that Site Is Not Archeologically Significant	Land Use	16 USC 402aa et.seq.
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 16.20.220 and .260
Department of the Interior Office of Surface Mining	Surface Coal Mining Permit	Surface Coal Mining Operations	30 USC 1201 et. seq., Section 1256
Alaska Department of Natural Resources	Coal Exploration Permit	Development of Coal Mine of State Lands	Alaska Statute 27.20.010
	Coal Lease	Mining of Coal on State Lands	Alaska Statute 38.05.150

source" if the heat input rate is greater than 250 MBtu/hr and if the plant has the potential to emit at least 100 tons per year of any air pollutant after controls have been applied. To obtain a PSD permit, an applicant must demonstrate that the source or modification will comply with the NAAQS's, the NSPS's, the NESHAP's, and PSD increments. In addition, the applicant must conduct analyses relative to the effects on soils, vegetation, visibility, and area growth.

PSD increments are specified maximum allowable increases in the ambient concentrations of SO_x and particulate matter, over a designated "baseline" concentration of these pollutants. These increments are based upon the classification of the attainment area as either Class I, II, or III. The allowable PSD increments increase from Class I to Class III, therefore, disregarding other considerations, Class I areas are the most restrictive for new industrial growth. Class I areas in Alaska include Denali National Park, the eastern boarder of which is near the Nenana field. If the plant is located within 10 km of this Class I area, additional pollution controls must be applied. However, the proposed Nenana Station would be to the north, near the community of Nenana (Figure 1.1)

Requirements will be imposed in order to protect visibility in designated Class I areas. Under rules promulgated on December 2, 1980 (45 FR 80084), new sources that require PSD permits may be required to conduct additional studies to determine the source's effects upon the visibility in the Class I area. Note that CAA Section 165 requires that PSD permits be denied for sources that would cause adverse air impacts on these federal Class I areas.

6.1.2 Water

The preservation of the quality of the surface waters of the United States is accomplished in accordance with the Clean Water Act (CWA). There are two major regulatory programs mandated by this act with which a coal-fired power plant must comply.

Controls will be imposed upon the discharge of pollutants by the power plant through the National Pollutant Discharge Elimination System (NPDES) permit. This permit is issued by the EPA pursuant to CWA Section 402, and regulations for its issuance are found in 40 CFR 122. The issuance of an

NPDES permit to a new discharge source will trigger the environmental review requirements of the National Environmental Policy Act (NEPA), as discussed below. Because the discharge cannot take place without a permit being issued, an application must be filed at least 180 days before the discharge is scheduled to commence.

The EPA has established effluent limitations for pollutant discharges on an industry-by-industry basis. New limitations for steam-electric generating units were proposed on October 14, 1980. When these become final, they may include more stringent controls on discharges than those presently in effect, especially with respect to discharge of toxic pollutants such as chlorine. Other aspects of these regulations may be relaxed however, such as those limiting pollutant concentrations in bottom ash transport water. The EPA is also in the process of developing effluent limitations controlling the discharge of toxic pollutants under the authority of CWA Section 307.

Pursuant to Section 404 of the CWA, a permit must be obtained from the U.S. Army Corps of Engineers (Corps) to discharge dredged or fill material into waters of the United States. Coal-fired power plants may need a Section 404 permit for construction activities such as the building of water intake or outfall structures, loading or unloading facilities, and transmission power lines.

With respect to the same activities, a power plant may also be required to obtain a permit under Section 10 of the Rivers and Harbors Act (RHA) of 1899 for the placement of structures or the conduct of work in or affecting navigable waters of the United States. This permit is also issued by the Corps using the same application forms and processing procedures as those required for the Section 404 permit.

The processing of either of these permits can take 6 months or more, and requires that an EIS be prepared according to the requirements of NEPA.

6.1.3 Solid Waste

The Resource Conservation and Recovery Act (RCRA), as amended in 1980, imposes controls upon the handling of solid waste in the United States. At present, the major emphasis has been placed upon the control of hazardous solid waste. A formal hazardous waste management program that sets forth identification and handling requirements for generators of hazardous wastes; marking and manifesting requirements for transporters of hazardous waste; and a permitting program for hazardous waste treatment, storage and disposal facilities is currently being administered by the EPA.

The operation of a 200-MW coal-fired power plant could involve the generation, transportation, treatment, storage or disposal of hazardous wastes. Power plant wastes that may be hazardous include water treatment wastes, boiler blowdown, boiler waterside and fireside cleaning wastes, coal storage pile runoff, cooling tower blowdown, floor drainage wastes, storm water runoff, and sanitary and laboratory wastes. (Some power plant wastes, such as high-volume wastes produced by the combustion of coal [fly ash, bottom ash, and flue gas desulfurization sludge] and certain other wastes that are mixed with these high-volume wastes, are currently excluded from control as hazardous.) Accordingly, the owners and operators of the power plant may have to comply with the standards applicable to generators and transporters of hazardous waste, and may also be required to obtain an RCRA permit from the EPA to operate a hazardous waste treatment, storage or disposal facility.

The RCRA permit need only be obtained from the EPA if hazardous waste in amounts exceeding 1000 kg/month will be treated, stored, or disposed of on the plant site. If the waste is transported offsite for disposal in a licensed facility (such as a municipal dump), a permit need not be obtained. Furthermore, certain types of facilities, such as neutralization tanks, transport vehicles, vessels, or containers used for neutralization of wastes that are hazardous only due to corrosivity (40 CFR 264.1(g)), have been excluded from RCRA permit requirements. (This exclusion does not apply to surface impoundments.)

If an RCRA permit for operation of a hazardous waste treatment, storage or disposal facility is necessary for the power plant, it must be obtained before construction of the hazardous waste management facilities can commence. EPA only recently began accepting applications for RCRA permits from new treatment, storage and disposal facilities. Although no such permits have been issued yet, EPA anticipates the processing of RCRA permits to take at least 1 year.

6.1.4 Coal Mining

The Surface Mining Control and Reclamation Act (SMCRA) applies to surface coal mine operations and to the surface effects of underground coal mining. Activities that must receive a permit under SMCRA include coal exploration, surface mining, surface effects of underground mining, coal processing plants and support facilities outside the actual mine permit area, coal processing plants and support facilities within the actual mine permit area and, in general, any activity conducted on the surface of lands "in conjunction with" the mining itself. As the power plant located either near Nenana or near Beluga could be developed in conjuction with the coal mine and, therefore, incorporate one or more of these activities into the plant's operation, a SMCRA permit for mining-related operations could be required.

Prior to issuance of a permit, an applicant must submit a reclamation plan describing the condition of the land prior to mining and explaining how the land will be restored after mining. The permit applicant must also submit a performance bond with the application, to be returned when reclamation of the site is complete.

The SMCRA permanent program performance standards that must be met by permitees are primarily designed to protect water quality, ensure land reclamation after the mining operations are over, and ensure that certain safety measures are taken. Numerous challenges to the permanent program that have been filed in various courts (In re: Permanent Surface Mining Regulation Litigation, Civil Action No. 79-1144, DDC; and Virginia Surface Mining and Reclamation Association v. Andrus, Civil Action No. 78-0-224-B, WD Va) have resulted in the suspension of portions of the program's regulations, and delays in the implementation of the permit program.

6.1.5 National Environmental Policy Act

Section 102(2)(c) of the National Environmental Policy Act (NEPA) requires the preparation of an environmental impact statement (EIS) as a prerequisite for "major federal actions significantly affecting the quality of the human environment." Such actions include the issuance of licenses or permits to private parties for the construction of projects that would affect the environment. The issuance of a CWPS Section 10/404 permit by the Corps, as well as an NPDES permit to a new source (discussed above) both require the preparation of an EIS. (Neither a PSD nor an RCRA permit, by contrast, is considered "major federal actions" that could trigger NEPA requirements.) Accordingly, compliance with the requirements of NEPA is necessary for a 200-MW coal-fired power plant.

The Council on Environmental Quality (CEQ) promulgated regulations implementing NEPA in 1978 (see 40 CFR 1500-1508). These regulations require virtually all federal agencies to promulgate regulations that conform with CEQ's regulations. Among other provisions, the CEQ regulations require that:

- An agency be designated as the lead EIS agency when more than one federal agency must prepare an EIS. The lead agency has primary responsibility for EIS preparation and is to coordinate with all other interested agencies. (The lead agency is also encouraged to coordinate with any state agency that implements an EIS-type process.) Normally, EPA or the Corps or Engineers is the lead EIS agency for power plant projects.
- A scoping process be used to determine the scope of the EIS.
- A standard EIS format be used. The heart of this format is the presentation of the proposed project and of alternatives to the proposed project, and the environmental impacts of the proposal and the alternatives. For proposed power plant projects these alternatives include alternative fuels and plant sites. EIS's for power plants must also consider the environmental impacts of associated transmission systems and indirect impacts (e.g., the impact of coal mining, processing and transport).

In addition, it is recommended that applicants who know that their proposed project will activate the EIS process consult with the applicable federal agency to start the EIS scoping process even before the permit application is submitted. Note that while the actual EIS preparation is the responsibility of the federal agency, it has become common practice for the regulatory agencies to require the utility applicant to prepare an "environmental report" (ER) that is utilized by the agency in preparing the EIS.

EPA's NEPA rules that conform with CEQ's NEPA rules are found at 40 CFR 6. For guidance on preparing applicant ERs, EPA has also issued a document entitled Environmental Impact Assessment Guidelines for New Source Fossil Fueled Steam Electric Generating Stations (EPA-130/6-79-001). This document should be used in conjunction with EPA's NEPA rules. EPA's NEPA rules allow for the preparation of the EIS by a third-party contractor, if EPA is the lead agency and if EPA and the applicant agree.

The Corps' NEPA rules that apply to CWA Section 404 and RHA Section 10 permitting are found in Appendix B of 33 CFR 230 (see 45 FR 56779, Aug. 25, 1980) and in the Corp's proposed amendments to its permitting rules (see 45 FR 62732, Sept. 19, 1980). These rules should be followed if the Corps is designated as the lead NEPA agency.

Finally, on September 8, 1980 (45 FR 59189), CEQ issued three memoranda that are intended to further the purposes of NEPA. Two of the memoranda emphasize the need for EISs to analyze the effects of a proposed federal action on prime or unique agricultural land. The third memorandum emphasizes the need to protect rivers that are on the nationwide inventory of rivers that appear to qualify for inclusion in the Wild and Scenic Rivers System (which was created pursuant to the Wild and Scenic Rivers Act, a law discussed below).

6.1.6 Other Federal Requirements

In reviewing federal environmental requirements to which a fossil fuel-fired power plant may be subject, it is necessary to consider certain additional regulatory programs. Although these programs may not include permitting requirements, they contain certain requirements that can affect location and/or construction of a power plant.

The National Historic Preservation Act requires that federal agencies that license projects that could affect structures listed or eligible for listing in the National Register of Historic Places take such effects into account. The agency issuing the license must consult with the appropriate state agency and must give the Advisory Council on Historic Preservation an opportunity to comment on the proposal.

The Wild and Scenic Rivers Act has created a National Wild and Scenic River System that consists of river sections that possess outstanding scenic, recreational, geologic, biological, historic, cultural, or similar values. The purpose of the Act is to preserve these river sections in a free-flowing condition, and to protect their immediate environs for the "benefit and enjoyment of present and future generations." Under this act, any proposed project that would affect the free-flowing characteristics of the river section included in the system must be disapproved if it would have a direct adverse effect on the values for which the river section is so included. Thus, although a proposal for a power plant to be sited on a river section included in the system might be approved, such approval would be highly controversial.

The Endangered Species Act of 1973 requires the U.S. Fish and Wildlife Service and the National Marine Fisheries Service to publish lists of "threatened" or "endangered" plant and animal species (as defined by the Act), together with the species' critical habitats and the ranges over which they are threatened or endangered. This act requires that all federal agencies insure that their actions (such as authorizing or approving proposed projects) do not jeopardize the existence of any listed species or result in the destruction or adverse modification of species' habitats. If it is determined that a threatened or endangered species is present in the area of a proposed project, this act requires that a biological assessment be conducted to determine if such a species is likely to be affected by the proposed project. Compliance with the environmental review requirements of the Endangered Species Act is usually incorporated into the NEPA review process for a project.

The Fish and Wildlife Coordination Act requires any federal agency that is to license, permit, or otherwise authorize a proposed project, to consult with the U.S. Fish and Wildlife Service and any other agency administering wildlife resources in the project area when a proposed project would control or modify a water body. The purpose of the consultation is to prevent loss of or damage to, as well as, where possible, development and improvement of the wildlife resources in the project area. This act defines wildlife resources broadly, and includes the vegetation upon which the wildlife depend. It allows the relevant federal agency to impose siting restrictions or mitigation or enhancement measures upon the project. Note that compliance with this act also occurs during the NEPA review.

Executive Order 11988 (May 24, 1977) requires that if an agency proposes to allow activity in a floodplain, it must consider alternatives to the proposed activity and must include an evaluation of the proposal's affect in an EIS, if one is prepared. If the planned activity will occur on federal lands, it must also comply with Executive Order 11990 (May 24, 1977) that prohibits construction on wetlands unless there is no practical alternative.

Pursuant to Section 1101 of the Federal Aviation Act of 1958, the Federal Aviation Administration (FAA) requires that notice be given to the FAA before a construction permit is filed for any proposed construction or alteration that would be over 200 feet above gound level or would be within a specified proximity to an airport. This notice to FAA may have to be filed for various power plant structures or transmission lines.

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 broadens the federal government's ability to clean up hazardous substance releases that threaten the public health or the environment. The Act establishes a Post-Closure Liability Trust Fund that is to be comprised of revenues from a tax on hazardous wastes that is to be imposed on the owners/operators of disposal facilities that have received RCRA permits or interim status. However, the tax will not apply to hazardous waste that will not remain at such a disposal facility after the facility is closed. Hazardous waste management facilities at power plants that have obtained interim status or a final permit under RCRA will be subject to this tax if the hazardous waste in such facilities will remain after plant closure.

6.2 STATE REQUIREMENTS

6.2.1 Air

The emission of contaminants into the air is controlled in Alaska by requiring sources of air pollution to obtain an air quality control permit to operate. Contaminants that can trigger permit requirements include dust, fumes, mist, smoke, fly ash and other particulate matter, vapor, gas, odorous substances, and any combination thereof. Due to the emission of contaminants that accompanies the burning of coal as fuel, a coal-fired power plant must obtain an air quality control permit to operate.

Applications for air quality control permits to operate should be filed with the Alaska Department of Environmental Conservation (DEC) at least 30 days prior to the commencement of operations. Applications must be accompanied by: one set of plans and specifications describing the construction planned; a set of maps or aerial photographs showing land use and zoning around the facility; an engineering report describing planned operation, points of emission, estimates of the quantity and types of air emissions; a description of air quality control devices; an evaluation of the impact the air contaminants would have on ambient air; and plans for emission reduction during an air pollution episode.

Alaska statutes limit the DEC to 30 days for its review of an application for an air quality permit. However, it asks that applicants submit their federal PSD permit applications to the DEC at the same time that the application is submitted to EPA. The DEC will not start its 30-day review period until it receives a letter from the applicant officially requesting an air quality control permit to operate. Using this procedure, the DEC can review the relevant information through EPA's review period, taking advantage of the year's worth of monitoring data and other information contained on the PSD permit application. Then when the actual review period begins for the state permit, issuance can be accomplished efficiently. The emission control requirements that may be imposed upon the facility are set forth is Alaska Statute 46.03.140. Variances may be obtained in accordance with procedures in Alaska Statutes 46.03.170. Permits are usually issued for periods of 5 years.

6.2.2 Water

Section 401 Certification

According to Section 401 of the CWA, no federal license or permit to conduct any activity that may result in a discharge into navigable waters may be issued until the state in which the activity occurs certifies that the discharge will comply with the requirements of the CWA and state water quality control requirements. As a coal-fired power plant generally must obtain various federal permits involving such discharges (e.g., NPDES permit, Section 404 dredge and fill permit), it usually must obtain Section 401 certification of its activities from the state.

In Alaska, Section 401 certification is issued by the DEC pursuant to the administrative procedures in Alaska's Administrative Code (18 AAC 15). Applications for such a certificate are made by submitting a written request to the DEC, accompanied by copies of the facility's federal permit applications. Certificates will be valid for up to 5 years.

Approval of Wastewater Treatment Facilities

Should the power plant include facilities that collect, treat, and dispose of wastewater, the plans for those facilities must be approved by the DEC before construction can commence. Engineering reports, plans, specifications, a timetable for construction, and other information that may assist the DEC in its assessment of the impact of the activity on Alaska's waters must be submitted to the DEC. The DEC will issue its determination regarding the proposed construction within 30 days of receipt of complete plans.

Wastewater Discharge Permit

The discharge of wastewater into or upon the waters of the surface of the land or into a publicy operated sewerage system cannot be conducted in Alaska unless the discharge has been permitted by the DEC. As wastewater has been defined in Alaska to include sewage, waterborne industrial waste, and other wastes that are waterborne or in a liquid state, the discharge of wastewater by a power plant would be subject to this permit requirement. Alaska's regulations, however, provide that when the EPA issues an NPDES permit for a particular discharge, the NPDES permit will be adopted as the required state permit (Alaska Statues 46.03.110(e)).

Water Rights Permit

Any person who desires to take waters of the state of Alaska for exclusive use must obtain a water rights permit from the Alaska Department of Natural Resources (DNR). As the preservation of water for common use is a major concern in Alaska, this is often one of the most difficult state permits to obtain. The application for this permit should be submitted as far in advance of commencement of construction as possible (at least 6 months) and should be accompanied by plans and specifications for any dam that may be built. The permit review procedures, described in Alaska Statute 46.15.030-185, include an opportunity for comment by all present users of the water whose rights may be affected by the proposed new use.

6.2.3 Solid Waste

The development and operation of a solid waste disposal facility in the State of Alaska is subject to a permit issued by the DEC. The application for such a permit must include: detailed plans and specifications; certification of compliance with local zoning; a detailed report on the waste to be handled, methods of operation, equipment to be used, and ultimate site use. Applications must be submitted to DEC at least 60 days prior to the commencement of operations. Permits may be issued for periods of up to 5 years.

6.2.4 Coal Mining

The State of Alaska only regulates coal mining activities conducted on state lands. If the development of a source of fuel for the proposed facility requires the conduct of work on coal deposits on state lands, prior approval for such work must be obtained from the DNR for the plan of operations (Alaska Statutes 27.20.010).

DNR will issue a prospecting permit giving the applicant the right to search for coal on state lands for a period of 2 years (Alaska Statute 27.20.010). A prospecting permit may be renewed for one additional 2-year period.

If, during the permit's life, the applicant discovers a coal seam and can satisfy the DNR that coal is present in commercial quantities, DNR may convert the permit to a lease for the mineral-bearing lands. DNR may include stipulations describing the procedures that must be followed during mining. These stipulations could contain requirements controlling the conduct of active mining, as well as reclamation requirements to be satisfied when closing the site.

It should be noted that other permits, such as those described elsewhere in this inventory, might also be necessary for coal mining operations.

6.2.5 Other State Laws

In addition to the primary environmental protection permits described above, the State of Alaska has implemented a series of regulatory programs designed to protect the state's natural resources. These programs that require a permit, state approval, or state certification are listed and briefly described below:

1. Alaska Coastal Zone Management Program - Alaska Statute 46.40 - In accordance with the requirements of the federal Coastal Zone Management (CZM) Act, Alaska has prepared a CZM plan setting forth guidelines for the use of Alaska's coastal areas. Before a federal agency may issue a license or permit to an applicant for a facility in a coastal zone, the federal agency must confirm that the activity is consistent with the Alaska CZM. The CZM program in Alaska is administered by the Office of the Governor.
2. Anadromous Fish Protection Permit - Alaska Statute 16.05.870 - All projects that will affect the natural flow of a specified anadromous river, lake or stream supporting anadromous fisheries or that require use of equipment in such waters must receive a permit from the Alaska Department of Fish and Game. Based upon the source of water used by a power plant and ultimate plant design, receipt of this permit may be necessary.
3. Critical Habitat Permit - Alaska Statutes 16.20.220 and 260 - Any development within a critical habitat for fish or game must be approved by the Department of Fish and Game prior to commencement of construction. Permits may be obtained by filing a proposal with the Department.

6.3 LOCAL REQUIREMENTS

The environmental regulatory requirements imposed at the local level differ throughout Alaska.

The area surrounding the Beluga coal field is located in the Kenai Peninsula Borough. That organized 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 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. Those 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.

The area surrounding the Nenana coal field is not in an organized borough. As a result, formal zoning requirements or land use plans for that area have not been developed.

6.4 LICENSING SCHEDULE

This subsection presents a tentative front-end licensing schedule (Figure 6.1) for the construction of a coal-fired power plant in Alaska. It takes into consideration the major federal, state and local environmental regulatory requirements that must be satisfied. (A list of these requirements may be found in Table 6.1.)

The schedule indicates that the total licensing will take approximately 43 months. The activities that are on the critical path to commencement of construction of the project include: development of the plan of study for the project, procurement and installation of field monitoring equipment, the gathering of air quality and meteorological data, analysis of terrestrial ecology field data, preparation and review of the PSD permit application, preparation and review of the application for the state's Certificate of Public Convenience and Necessity,[a] and preparation and review of the applications for the NPDES and Corps' Section 404/10 permits (which are on the critical path due to the requirement that the permits cannot be issued until 30 days after the final environmental impact statement is completed).

(a) Issued by the Alaska Public Utilities Commission to anyone wishing to own, operate, manage or control a public utility.

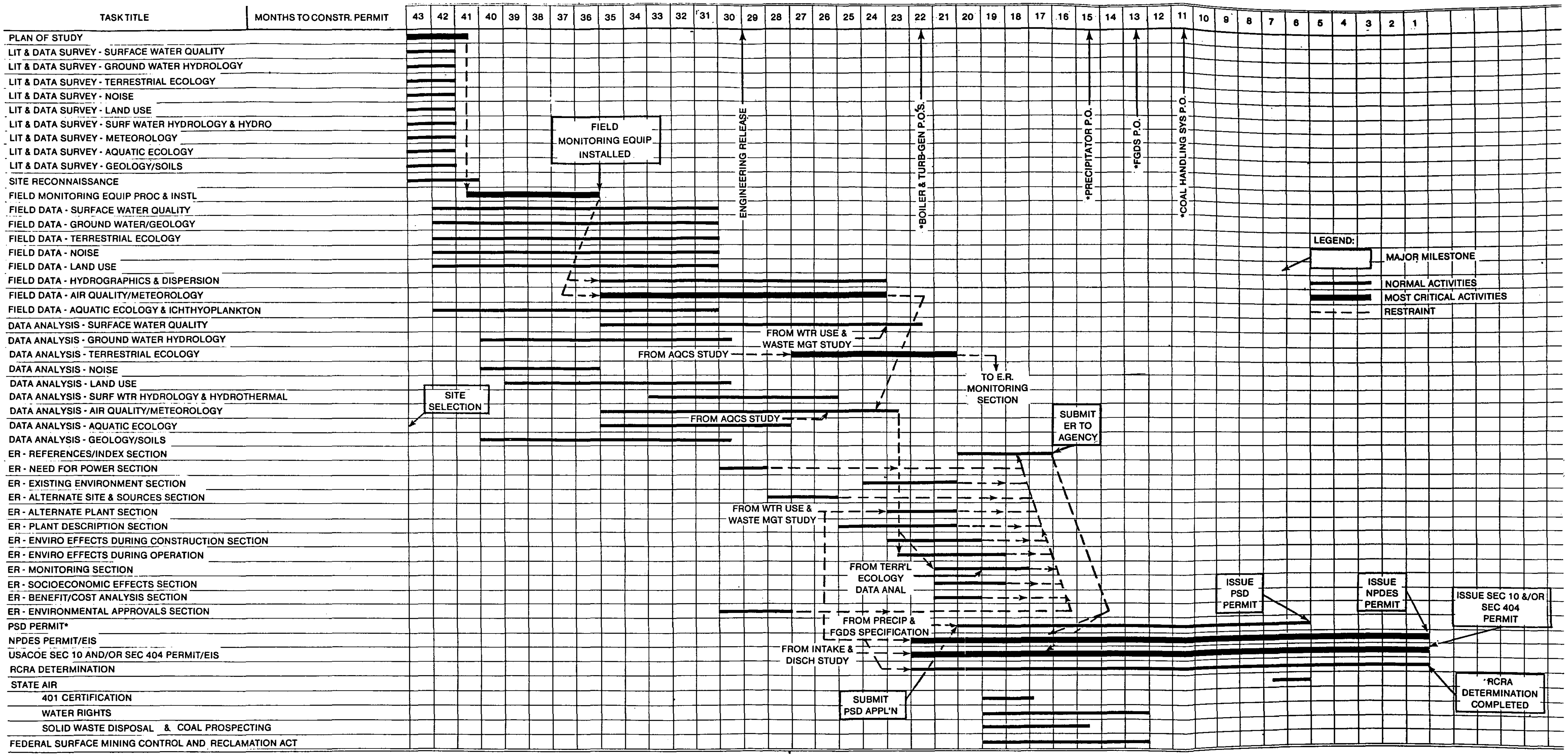


FIGURE 6.1. Licensing Schedule

In order for an applicant to prepare permit applications and an environmental report, it is necessary to develop conceptual engineering information on the systems of the generating plant that can impact the environment. Once that information is available, the development of a plan for satisfaction of the licensing requirements can proceed. It is suggested that representatives of the State of Alaska be included in the planning process as early as possible, in order to properly take advantage of the program for coordinated permitting which is under development and which will probably be in effect by the time this or an alternate project is initiated. Alaska hopes to have a single contact in the state coordinate applications for, processing and issuance of permits by state, local and perhaps even federal permits. The existence of such a contact could ease the burden on the applicant with respect to the time and effort that must be expended during the licensing process.

In general, site construction cannot begin until environmental requirements indicated in Figure 6.1 are satisified. More specifically, according to the Clean Air Act and EPA regulations, if a PSD permit is required for a project, an applicant may not begin continuous construction or enter into binding agreements or contracts for construction programs that can not be cancelled or modified without substantial loss until the PSD permit and all other necessary air quality/air emission approvals have been obtained. No dredged/fill material activity or other activity in surface waters can begin without a CWA Section 404/10 permit and no construction of a RCRA hazardous waste management facility can begin before a RCRA permit has been issued. Some site clearance activities can begin and some equipment can be purchased before permit issue. Such activity would require permission from state and federal agencies and would take place at the applicant's own risk.

7.0 REFERENCES

Bechtel Corporation. 1980. Preliminary Feasibility Study, Coal Export Program, Bass-Hunt-Wilson Coal Leases, Chuitna River Field, Alaska. Bechtel Corporation, San Francisco, California.

Commonwealth Associates Inc. 1981. Feasibility Study of Electrical Interconnection Between Anchorage and Fairbanks. Engineering Report R-2274. Alaska Power Authority. Anchorage, Alaska.

Swift, W. H. 1981. Alaska Coal: Future Availability and Price Forecasts. Battelle, Pacific Northwest Laboratories, Richland, Washington.