SUSITNA HYDROELECTRIC PROJECT

FEDERAL ENERGY REGULATORY COMMISSION
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DEFINITION AND COSTS OF THERMAL POWER ALTERNATIVES TO SUSITNA

DRAFT REPORT

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Report by
Harza-Ebasco Susitna Joint Venture

Prepared for
Alaska Power Authority

Draft Report
November 1985

NOTICE

ANY QUESTIONS OR COMMENTS CONCERNING
THIS REPORT SHOULD BE DIRECTED TO
THE ALASKA POWER AUTHORITY
SUSITNA PROJECT OFFICE

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1.0 INTRODUCTION

The Susitna Hydroelectric Project is presented as the best alternative for future generation of the bulk of the electrical energy needed by the State of Alaska in the early Twenty-First Century. The thermal (heat) sources of electrical generation which must be considered in order to determine whether Susitna is indeed the best alternative are presented in this document.

The available thermal alternatives are defined and described, and those that are true alternatives in terms of capacity and availability are then developed further. Technical definition, capital cost, and O&M costs are developed in sufficient detail to be used with existing industry models for analysis of the alternatives.

1.1 HISTORIC SOURCES OF THERMAL ELECTRIC GENERATION

The sources of electric generation using thermal energy may be placed in two categories. The first category is that utilizing directly fired combustion engines as the prime mover. This includes piston-type internal combustion engines, which may utilize a variety of fuels, including gasoline, diesel fuel, alcohol, natural gas or producer gas, and combustion turbines (CTs) which generally use natural gas, propane, or petroleum distillate as a fuel. The second category uses an indirectly heated medium expanded through an engine, such as a turbine, as the prime mover. Of the several thermal power cycles available in this category, the Rankine steam cycle is used almost exclusively. The heat sources used for this steam cycle include combustion of fossil fuels, biomass and waste products, nuclear fusion, and geothermal energy.

Internal combustion reciprocating engines are utilized for generation of electricity as emergency backup power in remote areas, or where the total demand for electricity is relatively small. Diesel engines, using petroleum distillate, are, by far, the most common type. Diesel generating units are available in sizes ranging from fractional megawatts up to the 25 MW range. They are reliable, can be started very quickly, and may be used for either base load or peaking power. Drawbacks to the use of diesel are size limitation, frequent maintenance, and requirements for a ready supply of relatively expensive fuel.

CTs are used to provide quick delivery and construction (in one year or less) of on-line capacity in sizes from 1 MW to 120 MW. The larger machines, however, are limited to 50 Hz service. CTs utilize an open Brayton cycle wherein air is compressed, heated by combustion with a fuel, and expanded through the turbine, producing mechanical energy and driving a generator. They are quick starting, follow load easily, are available at low capital cost, and provide significant operating and planning flexibility. Disadvantages of CTs are that they are less reliable than many alternatives, can require frequent expensive maintenance, have shorter lives, use relatively expensive fuels and lose efficiency when operated at part load.

The planning and operating flexibility attributed to CTs is derived from the different cycle configurations available. Although a simple-cycle CT may be used for base load, intermediate, peaking, or standby service, it is best suited for peaking or standby. The simple addition of regenerative heating of combustion air, utilizing heat from the exhausted gases, improves the cycle efficiency significantly. This makes the unit better suited for intermediate or base loading, but reduces reliability due to increased operating temperatures. Another configuration is to utilize the hot exhaust gas for steam generation by adding a Rankine cycle steam turbine generator to the system. This combination of Brayton cycle CT with a Rankine cycle steam plant is called a combined-cycle plant. Combined-cycle plants are the best suited arrangement for base load applications.

Steam-electric generating stations may be characterized according to their heat source, geothermal, nuclear, or combustion. Geothermal plants are practical only where large quantities of steam or heat are available from the earth, such as Rekjavik, Iceland; Geysers, California; or Yellowstone, Wyoming. The plants are usually very expensive, inefficient, and small in size (1 MW to 20 MW) due to the low quality and quantity of steam. The exception being the 66 MW units at Geysers, California.

Nuclear power plants rely on the heat of fission of transuranic elements for generation of steam to produce electricity. Although the early nuclear power plants were built in the 50 MW to 200 MW range, present day designs are 800 MW and larger. Nuclear power has very high capital costs, a long design-construct lead time, is very slow to bring on-line, and is plagued with environmental, safety, and licensing problems. Very low fuel costs and high reliability are also characteristic of nuclear power plants.

The overwhelming majority of steam-electric generating stations use chemical combustion of fuel as their source of heat for generation of steam. Most use the fossil fuels: coal, oil, and natural gas, with coal being predominant. Other fuels which are used are wood (biomass) and Municipal Solid Waste (MSW). Biomass-fired plants tend to be smaller in size, 60 MW or less, the most common around 10 MW. This size limitation reflects the costs of transport and handling of a sometimes unreliable fuel source. Plants which burn MSW are built for the primary purpose of waste volume reduction. Their capital costs are quite high, and their reliability, operating costs, and useful life are highly variable.

Fossil fuel-fired steam-electric generating stations are available in any capacity from 10 MW to 1,000 MW. However, economies of scale apply, and subject to availability and load requirements, larger plants may produce less expensive electricity. Coal is the fossil fuel most often used because of low cost compared to oil and gas. While coal-fired plants are more costly to build than oil- or gas-fired plants, they have low fuel costs, are extremely reliable, have a long useful life, and are the most used and proven technology for generating electricity.

1.2 THERMAL ENERGY SOURCES CONSIDERED FOR THE RAILBELT

The Railbelt Region of Alaska is rich in local energy resources and in resources available from adjacent areas. Depletable resources available include coal, oil, and natural gas. While the renewable resource of biomass from forests is also available, its accessibility and quantity are uncertain. Additionally, geothermal, MSW, and nuclear power were all considered as energy sources for the Railbelt.

Each of these resources is discussed below in terms of the specific parameters of each which affect its viability as an alternative. These parameters of evaluation vary from technology to technology, but are considered in terms of the criteria of fuel availability, reliability of the technology, size and total energy capacity, regulatory requirements, capital cost, and siting. Those technologies which are selected as viable are then evaluated in detail.

1.2.1 MSW-Fired Power Plant

MSW is omnipresent with civilization. The sheer volume of MSW created by an urban area which must be disposed of in a safe, environmentally sound manner, creates the need for volume reduction. The best volume-reduction method found to date is combustion. Combustion creates the possibility of steam-electricity generation. However, given a waste creation rate of approximately 5-1/2 pounds of refuse per person per day, the entire State of Alaska will produce only enough MSW in 1985 to support a 50 MW power plant. MSW cannot, even allowing for population growth, provide a significant alternative to the Susitna project.

1.2.2 Nuclear Power

There are over 150 nuclear power plants operating or under construction in the United States. Some have been in operation for more than 20 years. However, the costs of legally imposed constraints has prevented commitment of any new nuclear plants in the U.S. for several years.

There are no nuclear plants in operation or under consideration for Alaska. The nuclear steam-electric alternative for Alaska was addressed in detail in the Railbelt Electric Power Alternatives Study (Battelle 1981). A suitable site could be found in the Railbelt and the plant could be designed and built to meet all geological, environmental, safety, and operational requirements.

The generating capacity of commercially available nuclear plants is 800 MW to 1,100 MW. For an isolated system, such as that represented by the Railbelt, to depend on essentially all of its power from a single unit, a 100 percent standby reserve would be required.

A nuclear plant requires a refueling shutdown period of approximately 30 days every 12 to 18 months. This operating criteria will also act to force the construction and maintenance of a 100-percent standby reserve. This reserve would be needed at least once every 12 months during refueling and would, therefore, need to be a real and dependable source of electricity.

In view of the incompatibility of the unit sizes with Railbelt demand in the Year 2000 (an 800 MW nuclear plant would be approximately 95 percent of the estimated total peak of approximately 850 MW), nuclear power is not considered a desirable option to the Susitna project.

1.2.3 Biomass-Fired Power Plants

Biomass fuels, primarily wood and agricultural wastes, have been used for many years as sources of energy for electric generation. There are size limitations on biomass plants, generally due to the quality and quantity of fuel available (Bethel 1979 and Jamison 1979). The capacity of biomass plants is usually limited to 60 MW or less. As an alternative to Susitna, the potential biomass-generated electric capacity is insufficient. First, it has been estimated that biomass could provide no more than 0.5 to 5.0 percent of future Railbelt electric energy needs (Battelle 1981). Second, the main source of biomass in Alaska is wood. The life cycle for growing trees to a useful size as fuel is in excess of 100 years. For this reason, the fuel is considered nonrenewable.

1.2.4 Coal-Fired Power Plants

There are several coal fields in Alaska of which three are considered economically viable as sources of coal for electric generation. These are the Matanuska, Beluga, and Nenana fields.

The Matanuska field is good quality bituminous coal, but is small. The surface minable resources will be exhausted by the single plant presently proposed for the resource (Allied-Signal 1984).

The Beluga field is an extensive one consisting of low sulfur, high moisture, subbituminous coal. Development of a surface mine for export and domestic use by Diamond Alaska is presently in the permit application stage. A mine-mouth power plant using Beluga coal has been proposed by the mine developer. The coal reserves are sufficient to support several 8 to 12 million tons per year mines (Weirco 1984).

The Nenana field is located in the northern Railbelt near Healy and is currently being mined for domestic use and export. With further development, the field can supply the necessary increased capacity for an electric-generating facility.

Coal-fired steam-electric generating stations are the most widely utilized type of base load generation. There are several technologies for combusting coal to generate steam. The most advanced and most efficient is pulverized coal combustion. Pulverized coal-fired boilers are available in sizes from 10 MW to 1,200 MW. However, the smaller sizes, 50 MW and below, tend to be less cost effective than larger stoker-fired, grate-type boilers.

Drawbacks to using coal for electric generation in Alaska are primarily environmental. Air quality, water quality, and land use impacts can be significant; however, technology does exist which can mitigate these impacts to acceptable levels.

The presence of fuels and the status of the technologies for combustion and environmental controls make coal-fired, steam-electric generation a viable alternative to the Susitna project.

1.2.5 Natural Gas-Fired Generation

Most of the electricity consumed in Alaska is produced from natural gas. Supplies of natural gas are fully developed and readily available in the Cook Inlet area. There is some question regarding whether or not the supply could provide all of Alaska's electrical needs into the 21st century. However, supplies are available to allow planning generation through Year 2000. Additionally, North Slope natural gas may become available if a pipeline is built.

There are two well-developed technologies available for combustion of natural gas to produce electricity; there are simple-cycle CTs, and combined-cycle CTs. Either technology can be used to supply electricity in capacities from 10 MW to several hundred megawatts per plant. They can be used for base load, intermediate, or peak load; however, the combined cycle is more suited to base load than is the simple cycle. Both technologies are presently used extensively in the Railbelt and will be considered as alternatives to Susitna.

Natural gas-fired, steam-electric generation is also a possible alternative to Susitna. However, it is not considered further because the combined-cycle plant is less expensive to build and operates at a higher efficiency.

An additional factor to be considered is the Fuel Use Act. This Federal law prohibits construction of new gas-fired electrical generation for anything except peaking unless an exemption is granted by the Federal Government. All Alaska utility-requested exemptions have been granted to date; however, the political nature of this "permission" to construct creates additional uncertainty when planning to use this electric-generation resource.

1.2.6 Oil-Fired Generation

Petroleum distillates and residual fuels can be used in three ways to generate electricity. These are oil-fired steam-electric generation, CTs (either simple- or combined-cycle), and diesel engines.

Oil-fired, steam-electric generation is not being built or planned anywhere in the U.S. due to a combination of high fuel cost, alternative uses of petroleum products, and the legal prohibition by the Fuel Use Act. If use of petroleum distillate is considered for electric generation, then, like natural gas, the lower capital cost and higher efficiency alternative of a combined-cycle plant would be chosen for a base load plant while a simple-cycle CT unit is more cost effective for peak load applications.

Diesel generation is commercially available in sizes from fractional megawatts up to 25 MW. Larger sizes can be designed, but are not readily available, are overly complex, and would likely operate with reduced reliability.

The availability of petroleum distillate or residuals for electric generation is questionable. Although there are very large petroleum resources in Alaska, alternative uses (export), relatively high prices, and a lack of refining capacity require that oil-fired generation not be an alternative to Susitna. The one potential exception would be if small or peaking generation were to be an absolute requirement in an area where natural gas cannot be made available. In all likelihood, an oil-fired CT generation plant would be constructed in that locale.

1.2.7 Other Unconventional Thermal Sources

There are several developing or potential resources which could have application for electric generation in the Railbelt. These resources, discussed below, are fuel cells, solar energy, and geothermal energy.

1.2.7.1 Fuel Cells

In a fuel cell, the chemical reaction of oxidation of fuel is performed in an electrolyte bath with an anode and cathode present. The energy of oxidation is directly converted to electricity. Hydrogen is the most common fuel for reaction in the cell and is produced from methane, coal gas, or one of several other fuel sources. Plants which would utilize fuel cells will be easily variable in size, as well as fuel source. A typical "stack" of fuel cells will produce 500 amps of direct current at 300 volts. Any number of "stacks or single modules" can be grouped together to provide the required plant capacity.

The present stage of development of fuel cell technology is experimental. Some demonstration plants up to 10 MW in size have been built in the U.S. and in Tokyo (EPRI 1985). The availability, operating experience, reliability, and manufacturing capacity do not exist at present for this technology to be seriously considered.

1.2.7.2 Solar Energy

There are two existing methods for converting solar energy to electricity. These are photovoltaic cells and solar thermal conversion (Battelle 1981). Photovoltaic cells convert solar energy directly to electricity by the activation of electrons in photosensitive substances. Thermal conversion requires heating a fluid medium, such as water, and mechanically operating a generator as in a Rankine steam cycle.

The limiting criteria for either method are the amount of solar energy available, the efficiency of conversion, and the ability to store large quantities of energy for both the diurnal and seasoned cycles which will be encountered.

The limitation of the available solar energy in Alaska, combined with a winter peaking system, result in rejection of solar energy or a viable alternative.

1.2.7.3 Geothermal

There are several geothermal energy resources in Alaska. These consist of hot springs in the northern Railbelt near Fairbanks, Toloma, and Baker, and hot igneous rock in the Wrangel Mountains, Mt. Spurs, Double Peak, and Iliamna. Very little is known of the potential (if any) of these geothermal system.

Development of geothermal energy is very expensive compared to the conventional alternatives ($3,500+/kW versus $2,500/kW). Extensive steam collection and heat transfer system are usually required. The units are typically small, 5 MW to 50 MW, and their location is frequently remote from load centers.

Lack of detailed information, geographical diversity, and expected high development costs make geothermal energy a poor candidate for an alternative to Susitna.

2.0 CRITERIA FOR CONCEPTUAL DEVELOPMENT

The thermal alternatives selected, from those discussed in Section 1.2, for development as economically and technically viable alternatives to Susitna, are coal-fired steam-electric generation and natural gas-fired CT generation. The criteria which guided the conceptual design of these alternatives are discussed here.

2.1 COAL-FIRED

Coal-fired power plants are presently an integral part of the total power supply for the Railbelt. This is especially true of the northern Railbelt where Fairbanks Municipal Utility System (FMUS), Golden Valley Electric Association (GVEA), the University of Alaska Fairbanks, and Fort Wainwright all operate coal-fired power plants. The plants range in size from 1.5 MW to 26.5 MW. The public utility plants included are four coal units at FMUS Chena Station of 5.0, 2.5, 1.5, and 20.0 MW size for Units 1 through 4 and the GVEA Healy plant of 26.5 MW. These plants exist due to the abundance and availability of coal in Nenana. The southern Railbelt also has readily available coal supplies in the Beluga and Matanuska areas, where several coal plants have been proposed. Coal has not previously been developed for electric power generation in the southern Railbelt due to the historical abundance and low cost of natural gas from the Cook Inlet gas fields.

Although there are some relatively exotic alternatives, such as coal gasification available, the proven feasible and most economic utilization of coal, as a source of electricity, is a pulverized coal-fired, steam-electric generating station. The only viable alternatives are stoker-fired plants or fluidized bed combustion units. It has been repeatedly shown, through 40 years of operation, that stoker-fired plants do not compete well economically with pulverized coal plants in sizes above the 25 MW to 50 MW range. Fluidized bed combustion is an emerging technology that is very successful in the 5 MW to 50 MW range. The technology for larger plants, 100 MW to 300 MW, is promising; however, the first plants in the 100 MW to 200 MW range are only now being constructed. It is not practical to propose unproved technology as a viable alternate to the Susitna project. Therefore, pulverized coal firing was selected as the most appropriate technology.

2.1.1 Plant Size and Configurations

The economics of construction and operation of coal-fired power plants dictates a size range of 100 MW to 300 MW for smaller power pools (Power Engineering 1983). Although economics of scale dictate that larger power plants cost less to build and operate on a $/kW and $/MWh basis, the size of the utility/power pool and the cost of unplanned outages for that utility dictate that smaller utilities and power pools are economically better off with smaller (100 MW to 300 MW) coal-fired units.

The 1982 Railbelt alternatives study selected a 200 MW coal-fired power plant as a representative unit size that would be reasonable for a system expansion analysis. Further analysis has subsequently been conducted to confirm that this size is the most economical coal option for the without-Susitna plan.

In reviewing the assumptions for the appropriate size of a hypothetical coal-fired power plant, an evaluation of the options for unit size ranging from 100 MW to 400 MW was performend. The evaluation considered the tradeoff between two major driving forces or factors: economies of scale and unplanned outages.

As the size of power plant units increases, economies of scale are realized as lower capital and O&M costs are derived on an unit-kilowatt basis. For example, a single 400 MW unit has a capital cost of about 80 percent of two 200 MW units and requires about 60 percent of the operations and maintenance staff.

The factor of reliability and unplanned outages recognizes that the output of a utility system is made up of diverse generation stations, all combining their capacity to meet the load. The loss of the largest single generating unit represents the design basis for the reliability and loss of load analysis.

A tradeoff between the two factors of economies of scale and the impact of unplanned outages was performed using the optimized generation planning (OGP) model. Within that model, the reliability assessment is based upon determining the cumulative capacity outages of the system. As generating unit sizes become larger, more capacity is installed to meet the reliability requirement specified in the model. Another calculation performed in the OGP analysis is spinning reserve. The spinning reserve criteria provides the grid with the capability of meeting system load should the largest unit experience an unplanned outage.

Since any hypothetical coal-fired unit larger than 200 MW would represent the largest unit in a without-Susitna system, a number of OGP expansion planning analyses were performed. The unit size evaluation initially consisted of allowing the OGP expansion planning program to select among 100 MW, 200 MW, 300 MW, and 400 MW units. (Sizes up to 600 MW were considered, but never selected by the program.) The resulting system plan included 100 MW and 200 MW units. In the next step, unit sizes of only 100 MW, 150 MW, 200 MW, and 250 MW were made available for system expansion. The program then selected a mixture of 150 MW and 200 MW units. An expansion planning program using only 200 MW units showed that the total present worth of the mixture of 150 MW and 200 MW units was essentially the same as the present worth of the program that limited plants to 200 MW as the only size. The 200 MW expansion program utilized in the license application was therefore validated and retained.

2.1.2 Steam Cycle Selection

Boilers, turbines, and feedwater equipment are commercially available in several pressure/temperature ratings and configurations for steam-electric generating plants in the size range considered here. An overall criteria for equipment selection was to provide proven, reliable equipment with long records of high availability at the best possible efficiencies.

2.1.2.1 Boiler

A 2,500 psig/1,000°F/1,000°F boiler was selected to optimize boiler efficiency and fuel usage. This optimization results in higher capital costs than for an 1,800 psig or 1,450 psig cycle, but over the 30-year life of the plant, it will be paid back in increased output and lower heat rate. Single reheat to 1,000°F was selected to obtain an approximate four percent cycle gain.

The selection of the number of coal pulverizers (mills) was determined after review of the coal analysis. The Nenana and Beluga coals both have low hargrove index (28 to 32, average of 30), which indicates a very hard coal and high ash content, which, in turn, means a lot of pyrites or other hard tramp material will reach the mills. This will result in a great deal of wear and resulting maintenance on the mills. Therefore, a design using five mills rather than a standard four was chosen. This allows full load operation with one mill out for maintenance at any given time.

2.1.2.2 Turbine-Generator

Tandem compound flow turbines are virtually a utility standard. The presence of a reheat cycle means there will be a high pressure turbine with intermediate pressure (reheat) and low pressure turbines. Efficient operation of the plant dictates that regenerative feedwater heating with cascading heater drains be used. Optimizing this cycle, as discussed below in Section 2.1.2.4, will result in the lowest practical turbine heat rate. The turbine is provided with intermediate and low pressure steam extraction for supplying the required heat to the feedwater heaters.

The generator design criteria will conform to standard utility practices. It will operate with a power factor of 0.85 at design conditions and shall be supplied with a hydrogen cooling system.

2.1.2.3 Waste Heat Rejection

Best turbine performance is realized with the lowest possible exhaust pressure. The condenser will be designed to operate at two inches of mercury absolute backpressure. This is the best vacuum practical and is readily achievable given a low temperature heat sink.

In the Alaskan climate, the low ambient temperatures will ensure being able to design a cooling tower which will provide sufficient cool circulating water for maintaining the required two-inch HgA of condenser pressure. A potential problem will be dealing with the extreme cold weather to prevent icing of the tower and creation of local ice fog. Both problems can be dealt with by utilizing a wet/dry design. That is, in warm months the tower will operate as a wet tower. However, when icing conditions prevail, the hot circulating water will be cooled in dry sections and the wet sections will be isolated.

2.1.2.4 Feedwater System

Ebasco has performed repeated feedwater train optimization designs for 2,400 psig/1,000°F/1,000°F base load steam systems. The design settled on for optimum increased efficiency versus increasing capital cost is a seven-heater cycle. This includes four low pressure closed feedwater heaters, an open deaerating feedwater heater, and two intermediate pressure feedwater heaters. The basic criteria for selecting the number of regeneration heaters in a cycle is economic. The increased efficiency realized by recovering the heat of condensation that is otherwise rejected through the condensers must be worth more than the capital and operating cost of the additional equipment.

2.1.3 Emission Controls

2.1.3.1 <u>Sulfur Dioxide Removal</u>

Selection of the appropriate SO_2 removal equipment is as much a function of regulatory criteria as it is engineering criteria. Review of the Best Available Control Technology (BACT) to be applied for low sulfur coal on existing and under construction power plants show that no plants using less than 0.3 percent sulfur coal are operating or planned. Of those plants using coal with less than one percent sulfur, either wet (venturi) scrubbers or dry scrubbers are used. More recent designs are utilizing the dry scrubber systems which offer the best control of operating emission rates with less capital and operating costs than wet systems. Dry scrubbing was selected as most applicable for the very low sulfur (0.17 percent) Alaskan coal.

Determination of the actual operating parameters of the scrubber will follow from the determination of the plants emission rate, which is a purely regulatory function. Review of existing and planned plants in the U.S. determined that one plant is being constructed which will utilize a 0.32 percent sulfur coal and a dry scrubber with a resulting SO_2 capture rate of 80 percent (Power 1985). An SO_2 capture rate of 75 percent for the 0.17 percent sulfur Alaskan coal is proposed.

2.1.3.2 Particulate Removal

The selection of a fabric filter for flue gas particulate removal is dictated by two reinforcing factors. The resistivity of ash from low sulfur coal is typically low enough to create problems for operation of an electrostatic precipitator. Also, the calcium oxides (CaO) and gypsum ($CaSO_3$ and $CaSO_4$), which will be present in the flue gas downstream of the scrubber, will add to the design problem. It is necessary to design for dust collection over a wide range of ash, CaO, SO_2, and $CaSO_4$ concentrations in the flue gas. The possibility of operating for brief periods with the SO_2 scrubbing system off, means the electrostatic precipitator (ESP) will need to be greatly overdesigned. This variation of concentrations does not affect a fabric filter collector.

Three criteria affect the primary design of a fabric filter dust collection system. The cleaning method, bag material selection, and air-to-cloth ratio. The proven design of reverse air cleaning with high temperature fiberglass bags and a conservative net air-to-cloth ratio of 3.0 to 1.0 are assumed in this analysis.

2.1.4 Fuel Yard

The criteria for design of the fuel yard are reliability and size of fuel supply. A simple to operate and maintain radial stackout system was chosen for both reliability and low capital cost. An emergency stackout conveyor was added for reliability. Two underground reclaim hoppers are included, one for normal use at the active fuel pile, and an emergency reclaim at the dead storage fuel pile.

Due to the extreme weather conditions that exist at the proposed site, it is necessary to plan for a potential long interruption of fuel supply. For this reason, a 90-day rather than a more standard 60-day full load total on-site fuel supply is planned.

2.2 NATURAL GAS FIRED

2.2.1 Simple-Cycle Plants

2.2.1.1 Plant and Unit Size

The primary criteria for selection of both unit size and plant size is economic. That is, to be considered a viable technical and economic alternative to the Susitna hydroturbines, the units must be the least cost, most reliable, and should be available in size or combination of units that can replace single Susitna generating units. The large frame industrial gas-fired turbine selected is the largest commercially available that has both wide range utility application experience and with which the Alaskan Railbelt utilities have operating experience.

2.2.1.2 Plant Configuration

Since the purpose of these alternatives is to be considered as alternatives to Susitna project generation capacity, the complete natural gas-fired CT plant will, as nearly as practical, be sized to meet the needs of and conform to current practices of the Railbelt utilities. At International Standards Organization (ISO) conditions, 59°F at sea level, each unit is 80 MW. A three-unit plant with a total ISO rating of 240 MW and a net rating of 262 MW at the design ambient temperature of 30°F was chosen. It is planned that an initial single unit with switchyard, water treatment, and other auxiliary equipment for a complete three-unit plant would be built. The second and third units would be added as required.

The three-unit configuration was selected to optimize total plant cost. Construction of the initial unit at the site will include site development costs, and the basic switchyard. By planning the development and electrical equipment to include future units, the capital cost of the future units and the total plant is reduced.

Planning for more than three 80 MW CT's (ISO) with construction of the first unit would, however, burden the initial units capital cost heavily for generating capacity which may be as much as 10 years in the future.

2.2.2 Combined-Cycle Plants

2.2.2.1 Plant Size

The initial building blocks for the combined-cycle plant are CTs identical to those used for the simple-cycle plant. By using two CTs, each with a Heat Recovery Steam Generator (HRSG), and a single steam turbine, a plant with an ISO rating of 217 MW and a net rating of 230 MW at the design ambient temperature of 30°F was chosen.

2.2.2.2 Plant Configuration

As described above, the plant will consist of two CTs and a single steam turbine. This will allow construction of the plant in stages or as a complete plant. The initial CT installation would include electrical and auxiliary support equipment to serve the entire plant. This will simplify installation of the second CT and the steam turbine.

2.2.2.3 Steam Cycle Selection

The steam cycle used is determined by the level of complexity of the HRSG design. HRSGs may be single, duel, or even triple pressure units. With each additional higher pressure feedwater loop adding expense and complexity with the benefit of increased thermal efficiency. For simplicity of design and operation and to minimize capital cost, a single pressure HRSG was chosen.

3.0 THE COAL PLANT ALTERNATIVE

3.1 PLANT DESCRIPTION

The plant described is a single 200 MW (net) coal-fired, steam-electric generating station which may be built at either a Beluga or a Nenana site (See Figure 3-1). Other than location and fuel receiving facilities, all basic plant operating parameters are identical. Differences in capital cost due to site conditions and construction are addressed in the Capital Costs Section, 3.2.

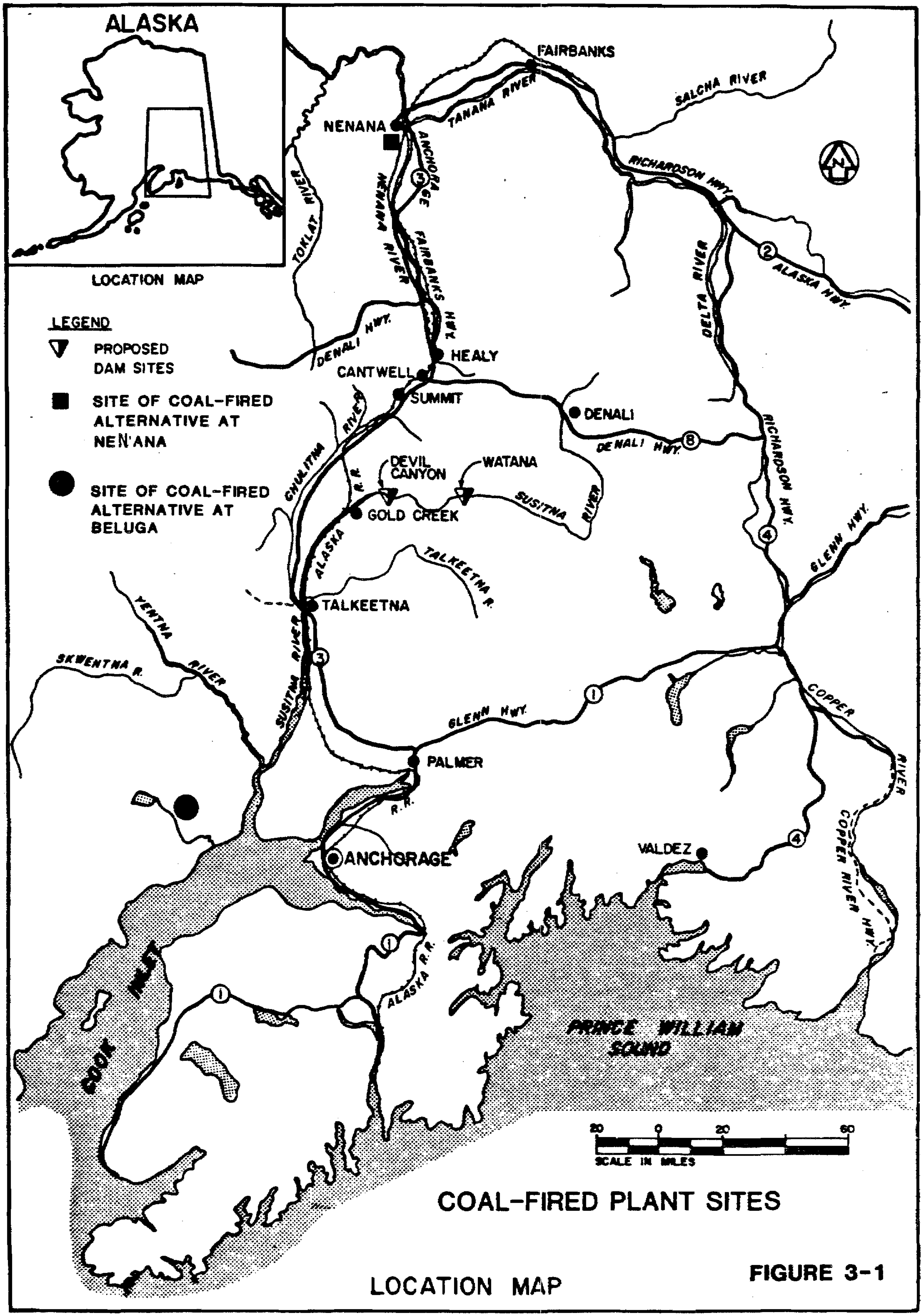
3.1.1 General Arrangement of the Plant

The plot plan of the plant is shown in Figure 3-2. Plant site development is configured around the initial siting of a 200 MW unit with the planned addition of a second. The plant site will occupy approximately 110 acres, excluding waste disposal facilities for air quality control system effluent. The generating station proper, consisting of the boiler house, turbine building, flue gas scrubber, precipitator, and chimney will be centrally located. Other buildings and facilities on the site include an administration building, maintenance building, warehouse, parking lot, switchyard, cooling tower, coal receiving, processing, storing, and retrieval facility, and wastewater holding and treatment facilities. General arrangement drawings of the power plant are presented in Figures 3-3 and 3-4.

3.1.2 Major Plant Components and Functions

3.1.2.1 Fuel Receiving, Processing, Storage, and Reclaim

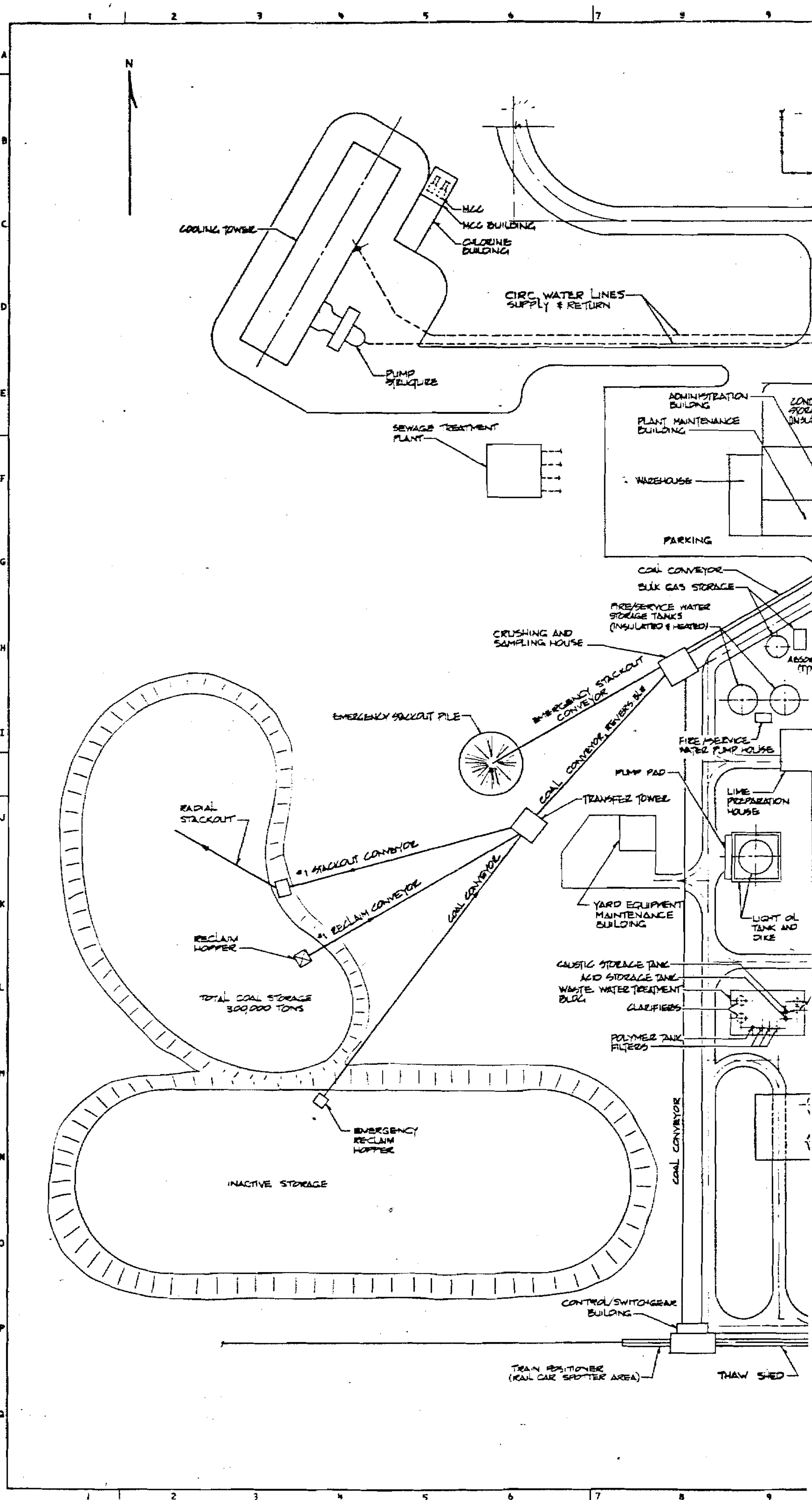
At the Nenana site, coal is received at a coal unloading station consisting of an enclosed rail car thaw shed, enclosed rotary car dump,



COAL-FIRED PLANT SITES

LOCATION MAP

FIGURE 3-1



N
COOLING TOWER
MCC
MCC BUILDING
CHLORINE BUILDING
CIRC. WATER LINES SUPPLY & RETURN
PUMP STRUCTURE
SEWAGE TREATMENT PLANT
ADMINISTRATION BUILDING
PLANT MAINTENANCE BUILDING
WAREHOUSE
PARKING
COAL CONVEYOR
BULK GAS STORAGE
FIRE/SERVICE WATER STORAGE TANKS (INSULATED & HEATED)
CRUSHING AND SAMPLING HOUSE
EMERGENCY STACKOUT CONVEYOR
EMERGENCY STACKOUT PILE
COAL CONVEYOR, REVERSIBLE
FIRE/SERVICE WATER PUMP HOUSE
PUMP PAD
LIME PREPARATION HOUSE
TRANSFER TOWER
RADIAL STACKOUT
#1 STACKOUT CONVEYOR
#1 RECLAIM CONVEYOR
COAL CONVEYOR
YARD EQUIPMENT MAINTENANCE BUILDING
LIGHT OIL TANK AND DIKE
RECLAIM HOPPER
CAUSTIC STORAGE TANK
ACID STORAGE TANK
WASTE WATER TREATMENT BLDG
CLARIFIERS
POLYMER TANK
FILTERS
TOTAL COAL STORAGE 300,000 TONS
EMERGENCY RECLAIM HOPPER
INACTIVE STORAGE
COAL CONVEYOR
CONTROL/SWITCHGEAR BUILDING
TRAIN POSITIONER (RAIL CAR SPOTTER AREA)
THAW SHED

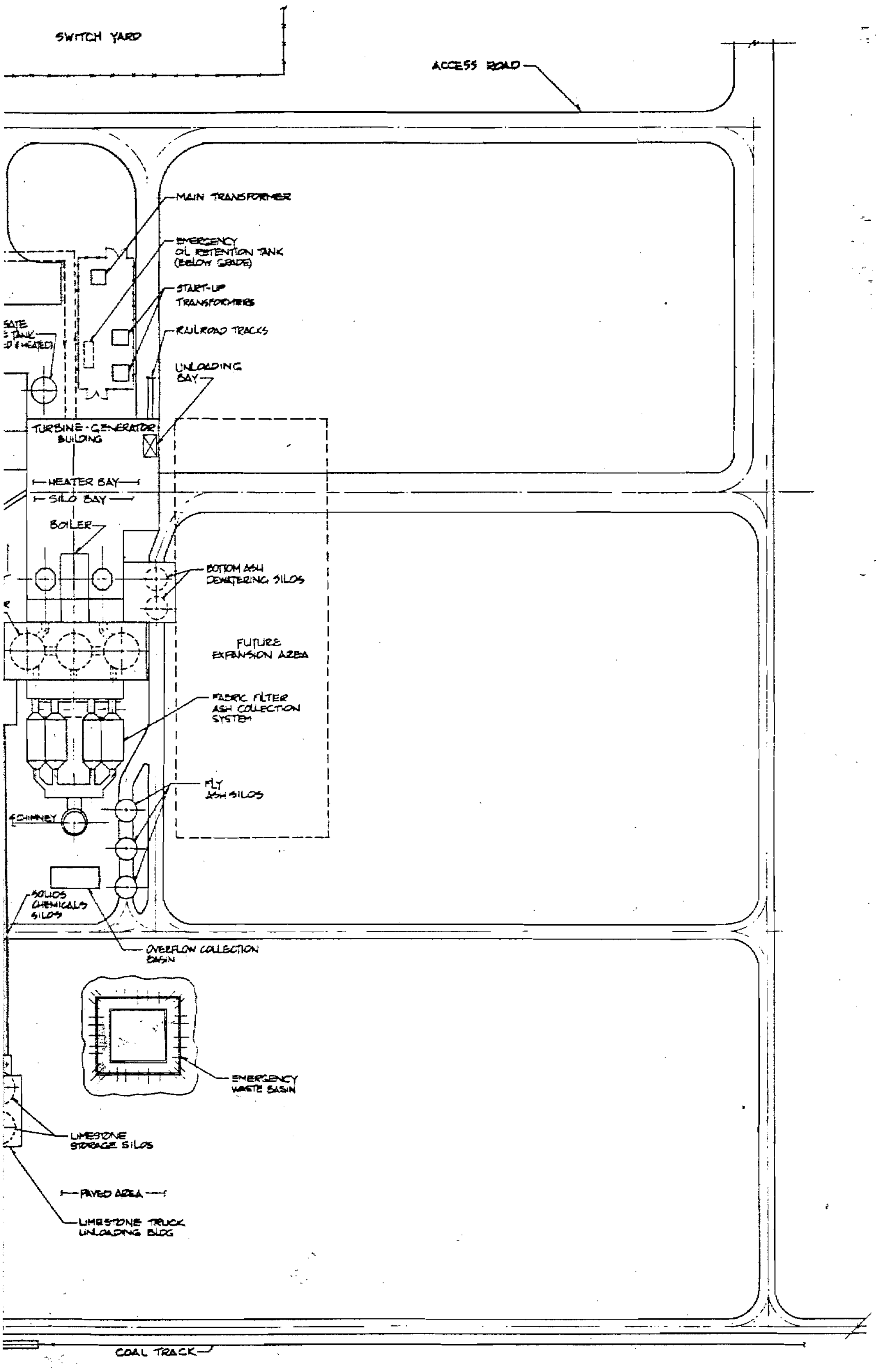


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FIGURE 3-2

HARZA-EBASCO
SUSITNA JOINT VENTURE

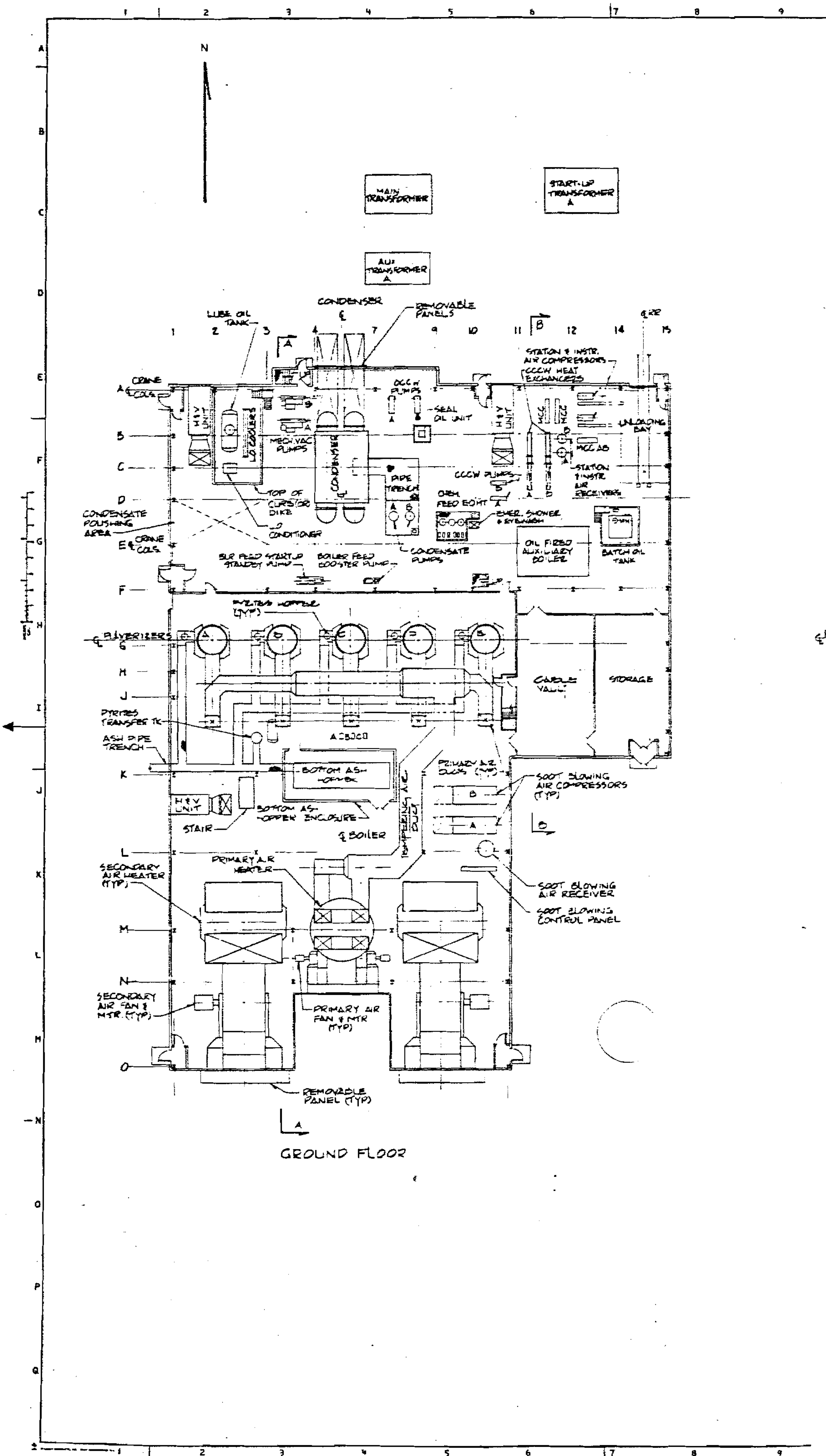
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

THERMAL ALTERNATIVE
200 MW COAL FIRED POWER PLANT
SITE PLAN

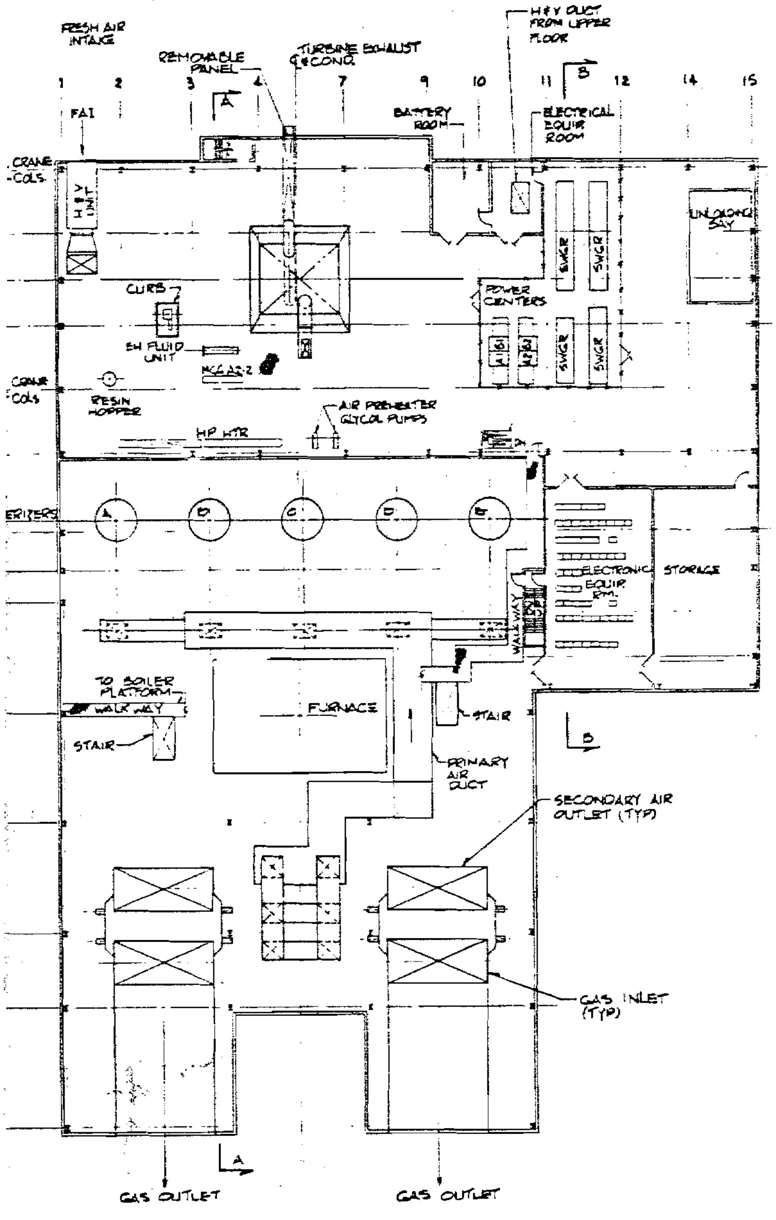
SCALE 1" = 60'-0 | APPROVED | DATE
DIV. MECHANICAL
DR. AVANT
CH

APA 2592.140
M-SP-001



GROUND FLOOR

NO	DATE	REVISION	BY	CH	APPROVED



MEZZANINE

FIGURE 3-3

PRELIMINARY ISSUES

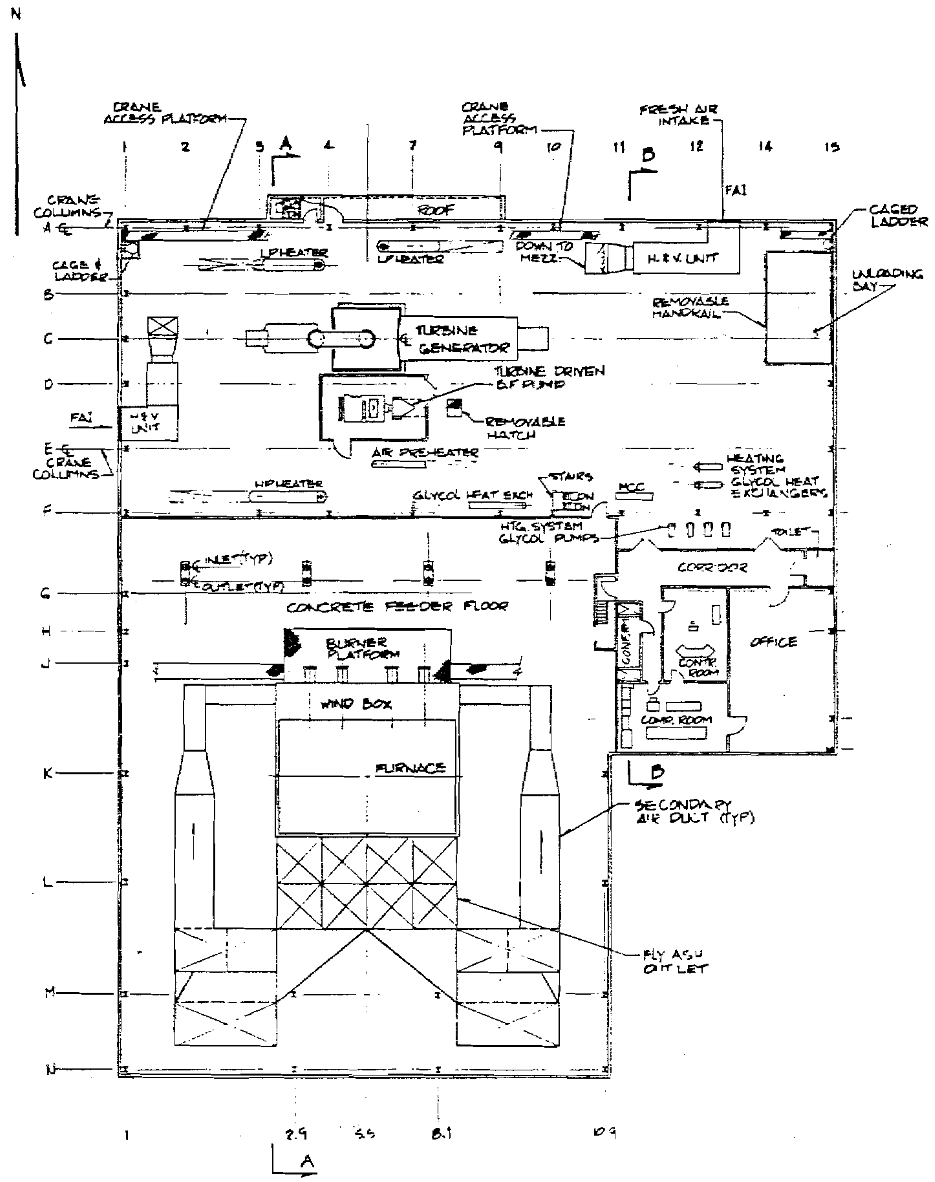
HARZA-EBASCO
SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

THERMAL ALTERNATIVE
200 MW COAL FIRED POWER PLANT
GENERAL ARRANGEMENT
PLANS

SCALE 1/16"=1'-0 | APPROVED | DATE
DIV. MECHANICAL
DR.
CK.
APA 2592.140
M-GA-002



OPERATING FLOOR

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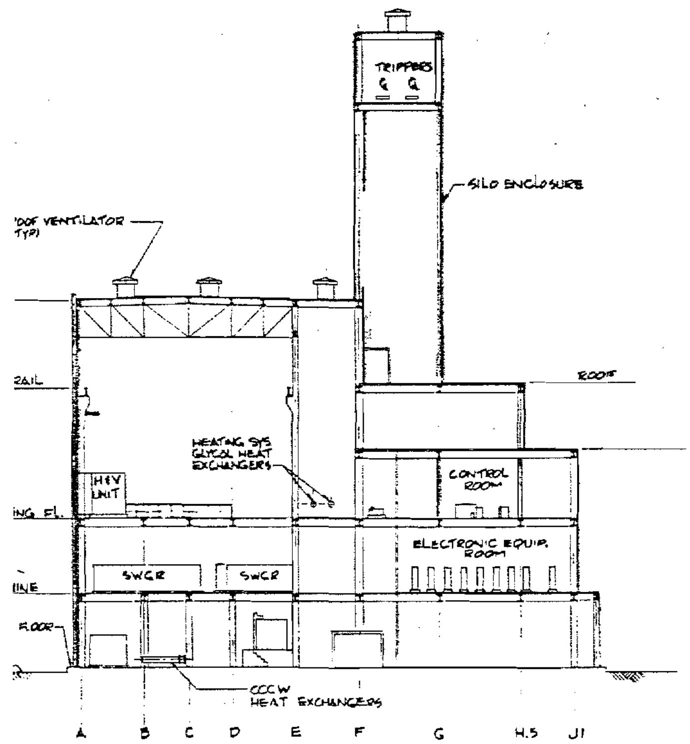
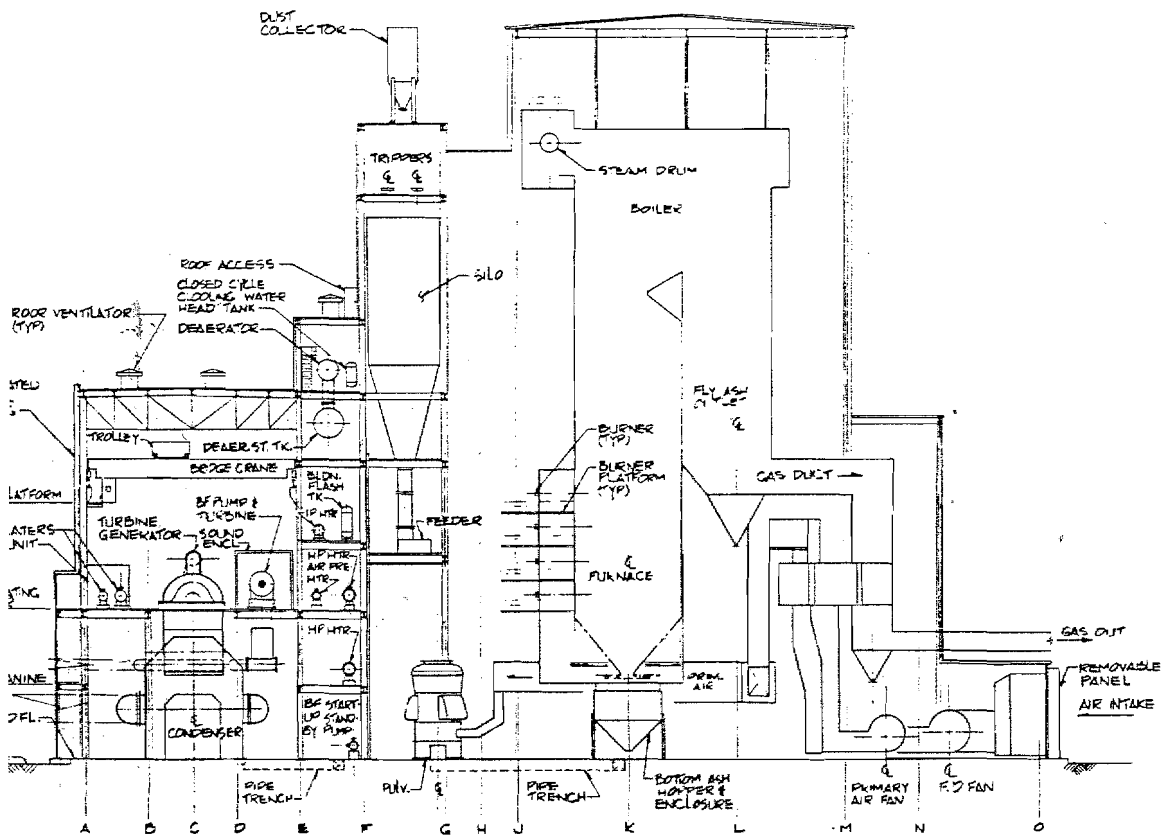


SECTION B



SECTION A

FIGURE 3-4

HARZA-EBASCO
SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

THERMAL ALTERNATIVE
200 MW COAL FIRED POWER PLANT
GENERAL ARRANGEMENT
PLAN & SECTIONS

SCALE 1/16=1'-0	APPROVED	DATE
DIV. MECHANICAL		APA 2592.140
DR.		M-GA-003
CH		

automatic car positioner, hopper, ice-lump breaker, and receiving conveyor. This system will accept a unit train of approximately 3,400-ton capacity and stockpile it in the active storage area of the coal pile for crushing, reclaiming, and transport to the plant.

If the plant is located at a Beluga site, the coal system will differ only in the receiving area. Coal will be received by truck rather than rail. There will be a multiple truck thaw shed and dual truck dump with receiving hopper. Otherwise, the coal-handling system will be the same as for a Nenana site.

From the unloading station, coal is transported by belt conveyor to the crushing and sampling house. Here the coal is crushed to a uniform size before transport either to storage or after further crushing directly to the coal silos in the powerhouse. Normal operation will result in the coal being sent to the coal yard for storage via the transfer tower, stackout conveyor, and radial stacker. All coal will be sampled "as received" at the crushing and sampling house using an approved ASME sampling method. In the event of downstream equipment failure, the coal-handling system may be emptied via an emergency conveyor to the emergency stackout pile.

Coal is normally retrieved from an underground reclaim hopper which is located in the live storage pile south of the radial stacker so as to also be accessible for retrieving coal from the dead storage pile. In the event of equipment failure, coal may also be reclaimed from the underground emergency reclaim hopper located at the end of the dead storage pile nearest the powerhouse.

Reclaimed coal is conveyed to the crushing and sampling house via the transfer tower and reversible conveyor. Here the coal is crushed to size for the coal pulverizers before being transported to the coal silos in the powerhouse. Crushed coal from the coal yard is distributed by the coal tripper into the coal silos for metering to the main plant coal pulverizers.

3.1.2.2 Combustion Air Supply

Combustion air for burning pulverized coal in the boiler is supplied from two sources. The primary air fans provide air to the coal pulverizers for the purpose of conveying the pulverized coal from the pulverizers to the burners in the boiler walls. Two secondary air fans provide the bulk of the combustion air to the boiler separately from the primary air system. All combustion air is preheated by regenerative air heaters and/or by a glycol/steam air heating system. Regenerative air heaters recover heat from the existing flue gas to preheat the combustion air.

3.1.2.3 Steam Generator

Coal is metered by gravimetric feeders to the pulverizers (coal mills), pulverized, then conveyed to the boiler by primary air as described above. There will be a total of five pulverizers which will distribute coal to the boiler for combustion at the rate of 135 ton/hr. The pulverizers are sized to maintain maximum continuous rating (MCR) with one pulverizer out of service when burning performance coal. Steam will be produced in the main boiler at 2,520 psig and 1,005°F for the purpose of delivering approximately 1.46×10^6 lbs/hr to the steam turbine generator set.

The coals to be burned at the Beluga and Nenana sites are very similar. Both are low-sulfur, subbituminous, Type C coals with relatively high ash and moisture contents. The performance coal analysis follows in Table 3-1.

The boiler consists of a waterwall section known as the furnace. Combustion takes place here and steam is generated in water-tube membrane walls from the radiant and convective heat transfer. The convective sections start at the furnace exit plane and consist of a superheat section where steam is heated to a temperature well above the

TABLE 3-1

PERFORMANCE COAL

ULTIMATE ANALYSIS, PERCENT BY WEIGHT

Element/Compound	Beluga 1/2/	Nenana 3/
Hydrogen	2.9 - 3.8	3.6
Carbon	44.7 - 45.4	47.2
Oxygen	14.4 - 15.8	15.5
Nitrogen	0.7	1.05
Sulfur	0.14 - 0.20	0.12
Water	24.9 - 28.0	26.1
Ash	7.9 - 9.9	6.4
Higher Heating Value, Btu/lb	7,600	7,600

1/ SRI, 1974.
2/ Diamond Shamrock, 1983.
3/ Hazen Research tests performed for FMUS.

saturation point, a reheat section where lower pressure steam returned from the high-pressure turbine is reheated before returning to the turbine, and an economizer section where incoming subcooled feedwater is heated by the exiting flue gas. Flue gas exits the boiler breeching and goes to the regenerative air heaters where it is cooled to 350°F. It then enters the dry SO_2 removal system.

Although most of the coal's ash content is carried away with the flue gas as "fly ash," 15 to 40 percent of the ash in the coal remains in the boiler as bottom ash and/or slag. This byproduct of combustion is collected in the bottom of the boiler. A water-sealed bottom ash hopper provides both ash cooling and a vacuum seal for the boiler. The bottom ash is removed by drag chains and broken by clinker grinders.

3.1.2.4 Turbine-Generator

The turbine is the prime mover for the power plant. It converts the thermal energy in the steam to mechanical energy. It is directly connected to the generator which converts mechanical energy to electrical energy. In order to accomplish this process, the main steam supply from the plant boiler is: 1) routed to the steam turbine generator; 2) expanded in the high-pressure section of the turbine; 3) returned to the boiler reheater section; 4) reheated and returned to the turbine where it is further expanded in the intermediate pressure section; and 5) subsequently expanded through the low-pressure turbine section. The steam exhausted from the low-pressure section is condensed in the main condenser and returned to the boiler for steam generation via a series of pumps and heat exchangers.

3.1.2.5 Feedwater and Condensate Systems

Expanded and cooled steam is exhausted from the turbine to the water-cooled condenser. The condenser, maintained at a vacuum to increase turbine efficiency, cools the steam sufficiently for it to condense and be pumped back to the boiler to repeat the cycle. Circulating water passing through tubes in the condenser carries away the heat of condensation to a cooling tower where the excess heat is rejected to the atmosphere.

A cooling tower of the wet/dry design will be utilized to provide cooling for the main condenser. Condensation of the exhausted steam by the cooling water maintains two-inch HgA condenser pressure. Water flow from the cooling tower to the condenser is approximately 87,900 gpm at 71°F dry bulb and 59°F wet bulb ambient conditions. Heat rejection from the plant cooling tower is approximately 1.0×10^9 Btu/hr when the turbine is exhausting 1.346×10^6 lbs/hr of steam at full load. During winter operations, the dry portion of the cooling tower is employed at the Nenana site to lessen the occurrence of ice fog. The plant performance is not greatly affected due to the large temperature differential which exists between the circulating water and the ambient air.

The condensed water in the well of the condenser is pumped via condensate pumps and boiler feedwater pumps through low-pressure and high-pressure feedwater heaters. In these heaters, steam is used to elevate the temperature of the feedwater prior to entering the boiler. Significant increases in cycle efficiency are realized through feedwater heating. The steam that condenses as the feedwater is heated flows to the next lower pressure heater where additional energy is removed from the condensate. The drains eventually are led to the condenser.

3.1.2.6 Flue Gas Cleaning Systems

Flue gas from the main boiler is exhausted to a semidry Flue Gas Desulfurization System (FGDS) for SO_2 removal. The FGDS will consist of three spray absorber vessels using a quick lime [$Ca(OH)_2$] slurry, of which two are sufficient to maintain proper flue gas sulfur removal. Lime may be received by either truck or rail, is stored in silos, mixed with water to form the quick lime slurry, and pumped to atomizers in the spray vessels. The lime slurry is atomized into the flue gas where SO_2 is captured to form $CaSO_3$ and $CaSO_4$ both of which are solid products. The FGDS will be designed to remove 75 percent of the sulfur dioxide from the gas stream at the unit's rated load which corresponds to 1.6×10^6 acfm at 350°F. Control of the spray dryer will be governed by gas temperature and SO_2 concentration of the exiting flue gas. The consumption of lime by the system is expected to average 1,900 pounds per hour. The solids formed are removed in the fabric filter (baghouse) downstream of the scrubber. The scrubber is referred to as "dry" because the amount of water injected into the flue gas is controlled to maintain the gas temperature above its adiabatic saturation point by a specified margin, usually 50°F or more. Two absorption vessels are required for operation at full load, one is a spare. Other equipment will include a powdered lime receiving, storing, and handling system, slurry mix tanks, slurry pumps, piping and the atomizers in the dry scrubber vessels.

Fly ash entrained in the flue gas stream, along with the calcium sulfates and remaining lime in the gas, are removed by the fabric filter. In the fabric filter, flue gas passes through a cloth filter media in the form of cylindrical bags. When passing from outside to inside the bag, a minimum of 99.9 percent of all solids in the gas stream are collected on the outside of the cloth bags. The baghouse will consist of eight or more compartments. When the bags are dirty, each compartment is isolated as required, the bags cleaned by passing air or cleaned flue gas through in the reverse direction, solids are collected in a hopper under the bags, and the compartment placed back in service. The solids collected in the hoppers are removed by a dry (vacuum) ash-handling system, then transported and stored in silos for later disposal offsite.

The baghouse system includes the baghouse proper, upstream and downstream ductwork, isolation dampers, ash transport, and storage and handling equipment.

Flue gas exiting the baghouse is exhausted to the main plant stack through an induced draft fan. If conditions require, supplemental clean air heated by process steam may be injected into the flue gas stream to avoid plume formation when discharged to the atmosphere.

3.1.2.7 Solid Waste-Handling and Disposal

There are three solid waste sources to be considered at a coal-fired power plant. The first two derive directly from the combustion of coal. They are bottom ash from the boiler and fly ash from the baghouse. Both must be disposed of in an imperviously lined landfill. The third waste stream consists of the various sludges and solids from the water treatment and wastewater management facilities. These come from various sources, such as settling ponds and clarifier blowdown. The sludge wastes are potentially hazardous and must be chemically stabilized before being landfilled with the bottom ash and fly ash.

Wet bottom ash is removed from the boiler bottom ash hopper by drag chain conveyors by which it is transported to elevated, enclosed bottom ash storage silos. Both the fly ash, which is handled dry and stored in silos, and the bottom ash are transported to an offsite landfill by truck.

3.1.2.8 Water and Wastewater Treatment

A central generating station is a user of large quantities of water. In addition to potable and domestic water, uses are for boiler makeup (condensate), lime slurry, circulating water makeup, and fire protection. Water for fire protection and the bottom ash hopper requires the least treatment, and will be supplied from either a settling pond via pumps or directly from the primary water source (such as a Ranney well system). Potable and domestic water, along with cooling tower makeup (due to evaporation and blowdown), and lime slurry water require more treatment. This will consist of settling basins, clarifiers, and chemical addition. The greatest amount of treatment is required for boiler feedwater makeup. Using the potable water system as a source, this water will be demineralized in an ion exchange system which is itself a user of water and a source of wastewater.

The plant will create several wastewater streams which require treatment prior to being released. The waste streams to be treated include sewage, clarifier backwash, demineralizer backwash, condensate polishing backwash, boiler blowdown, cooling tower blowdown, coal pile runoff, and storm drains. Depending on the relative cleanliness of each stream, these flows will be held up in settling ponds, run through clarifiers, and neutralized, as required, to meet standards for release to the environment. Settling ponds, clarifiers, chemical addition systems, and sludge-handling equipment necessary to perform these functions are included in the plant.

3.1.3 Plant Operating Parameters

3.1.3.1 Boiler Efficiency

In accordance with the standards of the American Boiler Manufacturer's Association, the plant's boiler efficiency was calculated using the heat loss method. Using this method, the total heat input to the boiler, the total heat losses, and the difference, which is the heat available, were determined. Efficiency is given as the heat available as steam divided by the heat input expressed as a percentage.

The boiler inputs for combustion are the fuel (coal) and combustion air. The higher heating value of the fuel is used to determine the heat input to the boiler. Heat input with the combustion air is virtually negligible, but is calculated based upon the air's heat content above standard temperature and pressure (STP).

There are several heat losses from the boiler. They are: 1) the heat contained in the flue gas and fly ash exiting the regenerative air heaters; 2) the heat contained in the bottom ash; 3) radiation losses; 4) leakage of air; 5) manufacturer's margin; 6) unburned carbon; and 7) boiler blowdown.

The calculated efficiency of the boiler for these plants using a coal analysis representative of either plant is 83.77 percent. This is slightly lower than for many coal-fired plants, but it reflects the relatively low heating value and high moisture and ash content of the fuels being burned.

3.1.3.2 Plant Auxiliary Loads

The power plant will consume approximately eight percent of the electricity generated when operating at full load. This consumption, used to operate the various systems which comprise the plant, is referred to as the plant auxiliary load. The components of the total estimated auxiliary load are listed in Table 3-2.

With the plant gross output of 217,636 kW, the auxiliary load is 7.99 percent of the gross capacity.

3.1.3.3 Heat Balance

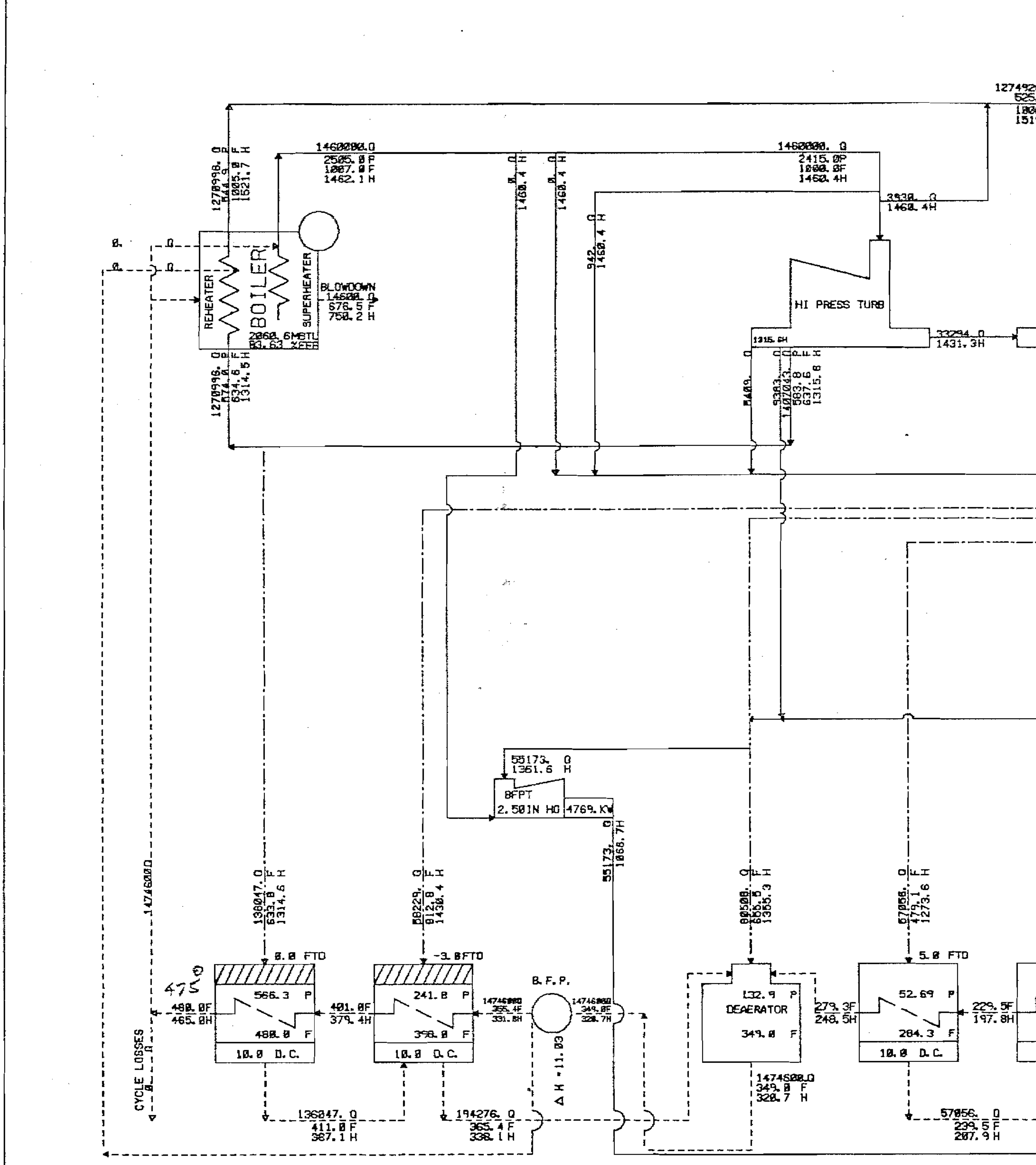
The heat balance for the plant is presented as Figure 3-5. The plant uses a seven-heater cycle, with four low-pressure heaters, a deaerator, and two high-pressure heaters. Reheat steam is used for the final high-pressure heater, intermediate turbine extraction steam for the second high-pressure heater and the deaerator, and low-pressure extraction for the low-pressure heaters.

TABLE 3-2

AUXILIARY LOAD

Steam Generator including ID and FD Fans	4,000 kW
Turbine Generator	420 kW
Coal Handling System	2,500 kW
Ash Handling System	800 kW
Boiler Feed Pumps	3,100 kW
Miscellaneous Pumps	3,000 kW
Makeup Demineralizer	200 kW
Condensate Polishing	200 kW
Wastewater Treatment System	275 kW
Cranes and Lifting Equipment	275 kW
Turbine and Boiler Bldg. HVAC	2,600 kW
Total Plant Auxiliary Load	17,370 kW

SHEET 1. OF 1.



PERFORMANCE

GROSS GENERATION KW	AUXILIARY POWER KW	NET OUTPUT KW	BOILER EFF. %	NET STATION HEAT RATE BTU/KW-HR
217636.	17411.	200226.	82.63	10416.
			83.63	10291.
			84.63	10170.

LEGEND

Q----FLOW-LBS/HR

P----PRESSURE-LBS/SQ. IN ABS.

F----TEMPERATURE- F

H----ENTHALPY-BTU/LB

FTD-TERMINAL DIFFERENCE (F)

ELEP-EXPANSION LINE END POINT

UEEP-USED ENERGY END POINT

D.C.- DRAIN COOLER APPROACH (F)

S.C.- SUBCOOLING (F)

——— STEAM

- - - - WATER

—·—·— EXTRACTION STEAM

SHEET NO.	THROTTLE FLOW LBS/HR
1.	1460000.

217636. KW LOAD
0.85 P.F. 45. PSIG H2
TURBINE NAMEPLATE RATING 217636. KW
AT 1460000. LB/HR THROTTLE FLOW, 2400 PSIG
1000./1000. F STEAM TEMPERATURE, 480.0 FFWT
AND 2.0 IN. HG. ABS. EXHAUST PRESSURE
GENERATOR RATING 260000. KVA AT 0.85 P.F
AND 45. PSIG H2 PRESS.

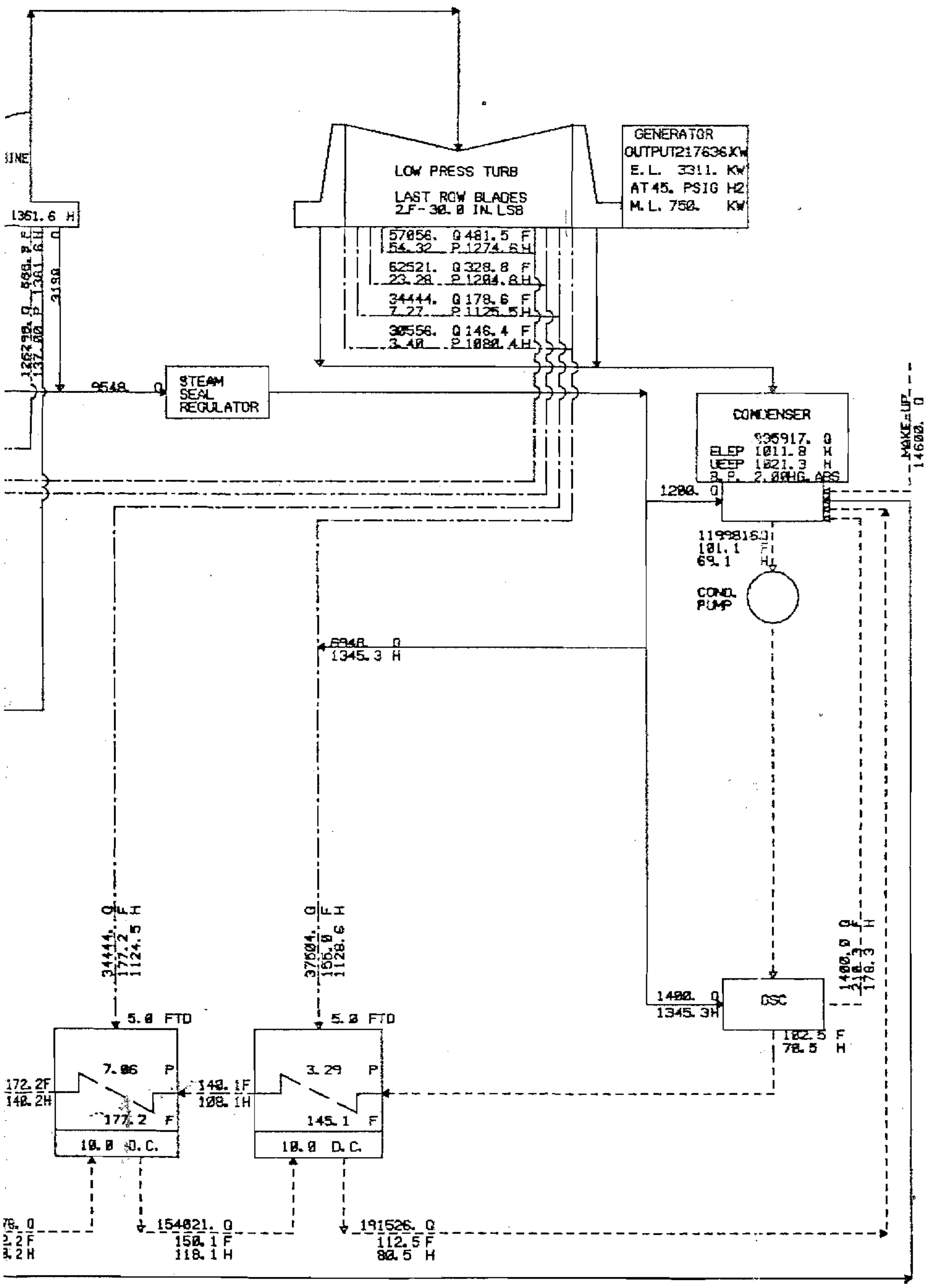


FIGURE 3-5

ESSURE	BACK PRESSURE IN. HG ABS	GEN OUTPUT KW	TURB HEAT RATE BTU/KW-HR
	2.00	217636.	7888.0

DRAWING DONE CAD SYSTEM EBASCO PROGRAM NO. 2017

ALASKA POWER AUTHORITY

SUSITNA COAL-FIRED ALTERNATIVE

HEAT BALANCE

EBASCO SERVICES INCORPORATED NEW YORK

SCALE-NONE	APPROVED	DATE 6/20/84
DIV. ___ DR. ___ CH. ___	JM 6/21/84	84-EB-226
		SHEET 1. OF 1.

NO.	DATE	REVISION	BY	CH.	APPROVED

3.1.3.4 Turbine-Generator Operating Parameters

At a full load of 1.46×10^6 lb/hr of main steam to the turbine, the generator output is 217,636 kW. The turbine is a tandem compound flow design with two intermediate pressure extraction points and four low-pressure extraction points and an extraction between the intermediate and low-pressure turbine piping in the crossover. The generator's power factor is 0.85 operating with a 45 psig hydrogen cooling system and two inches Hg Abs back pressure. The generator rating is 260,000 kVA.

3.1.3.5 Net Output and Heat Rates

The net output of the station will be 200,230 kW at full load after allowing for auxiliary loads. The turbine will have a gross heat rate of 7,858 Btu/kWh at full load. This is a direct measure of the amount of heat energy as steam required to produce a kilowatt hour at the generator bus. The net station heat rate is calculated based on the turbine heat rate, boiler efficiency, and subtraction of the auxiliary load to obtain the net output of the unit at full load. The net station heat rate is approximately 10,300 Btu/kWh.

The plant will be designed to have a capacity net factor of 80 percent of full load rating based on a 365-day year. The plant will produce a net of 1,402 GWh at the main transformer. This allows for time at partial load down to 100 MW net, with an availability of 90 percent or 7,884 hours per year. This is a conservative design parameter for this type of plant which considers the harsh environment at the proposed sites.

3.1.3.6 Other Operating Parameters

The plant mass flow rates and other operating parameters are summarized in Table 3-3.

TABLE 3-3

PLANT OPERATING PARAMETERS

	Nenana/Beluga
Fuel Consumption	135 tons/hr
Steam Generated/Pressure/Temperature	1,460,000 lb/hr 2,505 psia/1,005°F
Reheat Steam Flow	1,270,996 lb/hr
Flue Gas Volume	1.6×10^6 acfm
Lime Consumption	1,895 lbs/hr
Particulate Collection Efficiency	99.9 percent
Turbine Throttle Steam Flow	1,456,128 lb/hr
Turbine Exhaust	$1,395 \times 10^6$ lbs/hr
Waste Heat Rejected	1×10^9 Btu/hr
Circulating Water Flow, at 90°F.	87,900 gpm
Gross Generation	217 MW
Station Auxiliary Loads	17 MW
Net Generation	200 MW
Gross Turbine Heat Rate	7,858 Btu/kWh
Net Station Heat Rate	10,300 Btu/kWh

3.2 CAPITAL COST ESTIMATES

Separate capital cost estimates were prepared for the Beluga and Nenana sites. Further, separate estimates were prepared for the initial 200 MW unit at an undeveloped "Greenfield" plant site and a second 200 MW unit addition at that site. The estimates were prepared in 1983 dollars and escalated to 1985 dollars using Ebasco's Composite Index of Direct Cost for Electric Generating Plants (escalation factor of 1.0394). The Composite Index is based on historical data and reflects annual changes in cost of materials, equipment, and labor rates.

The coal plant and all subsequent estimates were prepared using two different data sources. Ebasco maintains a data base of plant cost estimates. This data includes material quantity estimates, labor quantity estimates, basic materials (steel, concrete, pipe, etc.) rates and labor rates. Based on the conceptual engineering design, the quantities are estimated from this data base for the size of plant being built. The rates were modified for the Alaska market and applied to the quantities to obtain costs. The second data source consists of equipment vendor quotes. The manufacturer's of the major equipment were requested to submit budget quotes for the boilers, turbine-generators, SO_2 scrubbers, and other major equipment. This was used with the Ebasco data to make a complete estimate.

3.2.1 Basis of Estimates

3.2.1.1 Plant Concept in Accordance With Description

The plant concept is described in Section 3.1 of this document, utilizing Beluga or Nenana coal.

3.2.1.2 Labor Assumptions

Wage rates are based on Anchorage union agreements for work south of 63 degrees latitude north and include workmens compensation, FICA, and public liability property damage.

- o Each workday will consist of ten hours of labor
- o Each work week will consist of six workdays
- o Sufficient craft personnel will be available
- o Labor will be housed and fed at on-site labor camps
- o Labor productivity is taken as "average U.S." with no adjustment

3.2.1.3 Financial Assumptions

The estimate does not include allowance for Funds Used During Construction (AFUDC) (frequently called interest during construction). It is also assumed that the project is exempt from sales tax.

3.2.1.4 Site-Specific Assumptions

Beluga:

- o Clearing and grubbing of brush and trees up to 25 feet tall is required
- o Eighty-foot long piles with heavy foundations will be required
- o Delivery of coal and lime will be by truck
- o A barge-unloading facility for heavy equipment is included

Nenana:

- Clearing and grubbing identical to Beluga
- Pilings and foundations identical to Beluga
- Delivery of coal will be by rail
- Delivery of lime will be by either rail or truck

3.2.1.5 Items Specifically Not Included

- Land and land rights
- Owner's costs
- Operating and maintenance costs
- Spare parts and special tools
- Maintenance machinery, laboratory, and office equipment

3.2.1.6 Included Indirect Costs

- Construction management local hire personnel
- Casual premium pay (other than schedule 60-hour week)
- Construction management automotive equipment
- Construction management office and expenses
- Temporary warehouse for prepurchased equipment
- Road maintenance equipment
- Gravel air strip
- Ten-mile 69 kV temporary transmission line
- Labor camp, food service, housekeeping
- Barge freight/off-site unloading adjustment
- Security guard service
- Craft transportation to and from labor camp
- Final construction cleanup

3.2.1.7 Professional Services

Professional services are based on a standard workday for engineering, design, site support engineering, and construction management services.

3.2.2 Details of Estimates

3.2.2.1 Beluga Site

Building a plant at a Beluga site is based on the premise that a major coal mine(s) will be opened there and that a coal export facility will be built. These assumptions are quite realistic. At least one major coal company is currently preparing an environmental impact statement (EIS) for both the mine and export facility.

Tables 3-4 and 3-5 present the summary level of the detailed estimates for the Beluga initial 200 MW unit and the Beluga extension 200 MW unit, respectively. The detail estimates are in Appendix A. Table 3-6 presents the capital cost summary for the Beluga coal-fired power plant including other related plant costs.

3.2.2.2 Nenana Site

The estimate for a coal-fired plant to be located at a Nenana site will be for a plant of the same size, type, and general configuration as that previously described for the Beluga power plant. Site-specific differences only are addressed here. Items which are not addressed are the same as for the Beluga power plant. The coal to be burned at Nenana is similar to the Beluga coal in details of analysis for ash, water, and heat content. However, the coal will be received by rail rather than truck. The coal-handling system is different in design and operation only with respect to receiving coal via a rotary rail car damper.

Transmission facilities are the same in concept as for the Beluga plant, but reflect only ten miles of transmission for Nenana while Beluga has 48 miles of 230 kV transmission line.

TABLE 3-4

CAPITAL COST ESTIMATE
BELUGA 200 MW COAL-FIRED POWER PLANT
INITIAL UNIT
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to site	4,170	1,212	2,958
2.	Earthwork and piling	34,998	15,158	19,840
3.	Circ water system	8,364	4,074	4,290
4.	Concrete	20,808	3,850	16,958
5.	Strct stl/lft eqp	27,960	10,909	17,051
6.	Buildings	18,662	6,016	12,646
7.	Turbine generator	19,503	16,777	2,726
8.	Stm gener and access	43,887	24,552	19,335
9.	AQCS	55,197	30,842	24,355
10.	Other mechan equip	20,368	15,063	5,305
11.	Coal and ash hndl equip	23,327	13,650	9,677
12.	Piping	28,649	10,104	18,545
13.	Insulation	7,038	593	6,445
14.	Instrumentation	7,230	6,650	580
15.	Electrical equipment	58,894	21,483	37,411
16.	Painting	2,276	159	2,117
17.	Off-site facilities	13,771	6,169	7,602
18.	Waterfront facility	8,018	1,932	6,086
19.	Substation/t-line	23,733	13,381	10,352
71.	Indirect const cost	41,891	0	41,891
72.	Professional services	55,907	0	55,907
100.	Contingency	68,989	23,093	45,896
99.	Total project cost	$593,640	$225,667	$367,973
300.	Total cost w/o contingency	524,651	202,574	322,077

TABLE 3-5

CAPITAL COST ESTIMATE
BELUGA 200 MW COAL-FIRED POWER PLANT
EXTENSION UNIT
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to site	332	174	158
2.	Earthwork and piling	14,094	7,656	6,438
3.	Circ water system	7,650	3,822	3,828
4.	Concrete	13,469	2,613	10,856
5.	Strct stl/lft eqp	19,493	8,493	11,000
6.	Buildings	9,331	3,263	6,068
7.	Turbine generator	18,872	16,138	2,734
8.	Stm gener and access	43,855	23,616	20,239
9.	AQCS	41,034	21,887	19,147
10.	Other mechan equip	14,219	10,288	3,931
11.	Coal and ash hndl equip	5,715	3,513	2,202
12.	Piping	26,012	9,223	16,789
13.	Insulation	7,000	571	6,429
14.	Instrumentation	6,954	6,396	558
15.	Electrical equipment	45,375	18,499	26,876
16.	Painting	2,171	132	2,039
17.	Off-site facilities	3,600	561	3,039
19.	Substation/T-line	18,596	11,284	7,312
71.	Indirect const cost	27,159	0	27,159
72.	Professional services	14,052	0	14,052
100.	Contingency	46,403	17,775	28,628
99.	Total project cost	$385,386	$165,904	$219,482
300.	Total cost w/o contingency	338,983	148,129	190,854

TABLE 3-6

CAPITAL COST SUMMARY
BELUGA COAL-FIRED POWER PLANT
TWO UNIT
(1985 $ in 1,000s)

Unit 1 Estimate	$593,640
Unit 2 Estimate	385,386
Subtotal	$979,026
Items Not Included in Estimate	
Town Site Cost	$18,333
Owners Cost (at 2-1/2% of Direct Project)	24,476
Startup, Spare Parts, and Special Tools	11,044
Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture	2,209
Land (200 acres at $10,920 per acre)	2,209
Subtotal	$58,271
Project Total Cost	$1,037,297
Average Cost per kW[1/]	$2,593

1/ Based on Two Unit Nominal Net Capacity of 400,000 kW. Average cost is presented in actual dollars, not 1,000s.

Indirects for Nenana are also similar to Beluga. The differences are listed below:

- o Fifteen-mile 69 kV temporary transmission line
- o No barge or off-site special handling or unloading adjustment

Tables 3-7 and 3-8 present the summary level of the capital cost estimates for the Nenana initial 200 MW unit and the Nenana extension 200 MW unit, respectively. The detailed estimates are included in Appendix A.

A capital cost summary presenting the total costs of two 200 MW units at the Nenana site is shown in Table 3-9. These costs are converted to 1985 dollars and owner's costs, cost of tools and spare parts, maintenance and laboratory equipment costs, and land costs are added to arrive at a total cost of $2,702 per kW.

3.2.3 Comparison of APA Capital Cost Estimates to Estimates for Similar Plants in Alaska

There are two comparable coal-fired power plant estimates available for comparison to the Alaska Power Authority Beluga site estimate. These are the 170 MW (150 MW net) power plant, as presented by Signal Energy Systems and the Beluga 150 MW (140 MW net) coal-fired power plant project proposed by Diamond Alaska Coal. The costs of the three plants are compared below in Table 3-10. There are no comparable estimates available for the Nenana site.

Details of the Signal Energy estimate were not available for comparison to either of the other estimates. However, the Diamond estimate was available, and the most notable differences are listed below:

TABLE 3-7

CAPITAL COST ESTIMATE
NENANA 200 MW COAL-FIRED POWER PLANT
INITIAL UNIT
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to site	8,399	2,565	5,824
2.	Earthwork and piling	42,350	17,133	25,217
3.	Circ water system	8,261	3,930	4,331
4.	Concrete	30,950	6,522	24,428
5.	Strct stl/lft eqp	30,141	11,322	18,819
6.	Buildings	19,269	5,974	13,295
7.	Turbine generator	18,851	16,097	2,754
8.	Stm gener and access	43,085	23,557	19,528
9.	AQCS	55,768	30,779	24,989
10.	Other mechan equip	20,219	14,675	5,544
11.	Coal and ash hndl equip	27,235	16,390	10,845
12.	Piping	30,127	9,765	20,362
13.	Insulation	8,436	827	7,609
14.	Instrumentation	6,966	6,380	586
15.	Electrical equipment	63,823	24,652	39,171
16.	Painting	2,467	165	2,302
17.	Off-site facilities	21,037	7,339	13,698
19.	Substation/t-line	10,788	7,956	2,832
71.	Indirect const cost	55,575	0	55,575
72.	Professional services	57,911	0	57,911
100.	Contingency	78,065	24,723	53,342
99.	Total project cost	$639,713	$230,751	$408,962
300.	Total cost w/o contingency	561,648	206,028	355,620

TABLE 3-8

CAPITAL COST ESTIMATE
NENANA 200 MW COAL-FIRED POWER PLANT
EXTENSION UNIT CAPITAL COST ESTIMATE
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to site	461	226	235
2.	Earthwork and piling	16,572	8,283	8,289
3.	Circ water system	8,113	3,854	4,259
4.	Concrete	16,339	3,636	12,703
5.	Strct stl/lft eqp	20,435	8,485	11,950
6.	Buildings	9,809	3,397	6,412
7.	Turbine generator	19,139	16,376	2,753
8.	Stm gener and access	43,497	23,970	19,527
9.	AQCS	41,588	21,833	19,755
10.	Other mechan equip	13,779	9,863	3,916
11.	Coal and ash hndl equip	6,525	3,612	2,913
12.	Piping	27,745	9,838	17,907
13.	Insulation	7,473	820	6,653
14.	Instrumentation	6,966	6,380	586
15.	Electrical equipment	53,650	19,463	34,187
16.	Painting	2,358	157	2,201
17.	Off-site facilities	3,199	601	2,598
19.	Substation/t-line	3,152	1,736	1,416
71.	Indirect const cost	33,968	0	33,968
72.	Professional services	16,531	0	16,531
100.	Contingency	48,417	17,104	31,313
99.	Total project cost	$399,706	$159,634	$240,072
300.	Total cost w/o contingency	351,289	142,530	208,759

TABLE 3-9

CAPITAL COST SUMMARY
NENANA COAL-FIRED POWER PLANT
TWO UNITS
(1985 $ in 1,000s)

Unit 1 Estimate	$639,713
Unit 2 Estimate	399,706
Subtotal	$1,039,419
Items Not Included in Estimate	
Owners Cost (at 2-1/2% of Direct Project)	$25,985
Startup, Spare Parts, and Special Tools	11,044
Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture	2,209
Land (200 acres at $10,920 per acre)	2,209
Subtotal	$41,447
Project Total Cost	$1,080,866
Average Cost per kW1/	$2,702

1/ Based on Two Unit Nominal Net Capacity of 400,000 kW. Average cost per kW is presented in actual dollars, not in 1,000s.

TABLE 3-10

PLANT COST COMPARISONS

Plant Estimate	Total Cost ($ x 000)	Net Capacity	Unit Cost
APA Beluga Plant	$1,037,297	2 - 200 MW	$2,593/kW
Diamond Alaska Beluga Plant	$319,553	1 - 141 MW	$2,266/kW
Matanuska Power Project	$375,000	1 - 153 MW	$2,451/kW

ITEMS INCLUDED IN THE APA PLANT AND NOT IN THE DIAMOND PLANT

- A complete coal-handling system with thaw shed, stackout and reclaim, 90-day storage, nine conveyors, crushing, and sampling
- A 20-mile access road
- A 48-mile 230 kV transmission line
- A ten-mile temporary 69 kV transmission line
- Mooring and dock facility
- Ranney well system
- Substation

ITEMS DIFFERING SIGNIFICANTLY BETWEEN THE TWO PLANTS

- Boiler - APA estimate is for a 2,500 psi, Diamond's is 1,450 psi.
- Pilings, Foundations and Earthwork - The APA estimate includes 80-foot piles with foundations. The Diamond estimates appear to include only spread footings. Additionally, there is not allowance for earthwork or concrete apparent in the estimate.
- Structural Steel - The Diamond estimate includes 1,650 tons of steel; the APA estimate is 4,740 tons.
- Electrical - Diamond's electrical installation includes 139,177 work hours. The APA estimate has over 400,000 work hours for electrical installation, not including the transmission lines.

- Step-Up Facilities - In addition to the transmission line, the APA estimate includes a step-up transformer yard which is not in the Diamond estimate.

- Site Development - Diamond estimate is for a site already partially developed for the coal port, development costs are $1,359,600. The APA estimate is for an undeveloped site with development costs of $4,076,000.

- Piping - With a higher pressure boiler and turbine, all steam piping in the APA estimate will be more expensive.

- Camp Costs - The Diamond estimate uses $50/day, the APA estimate $63/day.

- Total Work Hours - The Diamond estimate includes a total of 1,672,387 work hours. This is less than half the 3,467,000 hours used in the APA estimate.

- Union Versus Nonunion - The Diamond estimate assumes the ready availability of nonunion labor. The APA estimate uses union labor in accordance with Anchorage union agreements.

- Turbine Bypass - The APA estimate includes design for the main steam to bypass the turbine. In the event of unit trip, steam will dump to the condenser to facilitate a rapid restart of the plant (a common practice in Europe and Canada at remote site locations). The Diamond estimate does not appear to include this.

The addition of the details in Table 3-11 and associated costs to the Diamond estimate results in an adjusted price of $2,965/kW.

TABLE 3-11

CAPITAL COST VARIANCES FOR ITEMS
NOT INCLUDED OR DIFFERING SIGNIFICANTLY
IN COST COMPARISON

Item	Estimated Cost Differential of 200 MW Plant over 140 MW Plant	Differential Unit Cost $/kW (net)
Coal handling 1/	$13,580,000	96
Access roads 2/	1,037,000	7
Transmission line and step up 2/	25,404,000	180
Mooring and dock facilities 2/	7,838,000	56
Ranney well system 2/	3,084,000	21
Boiler	3,300,000	23
Earthwork pilings and concrete 1/	35,000,000	248
Site development 1/	1,697,000	12
Camp costs 3/	2,536,000	19
Turbine bypass system 2/	2,850,000	20
Total	$96,326,000	683

1/ Based on scaled costs of 200 MW plant.

2/ Same case as used for 200 MW plant.

3/ Based on Diamond's hours to construct.

3.3 O&M COSTS

In order to utilize the OGP model and Multiple Area Production Simulation Program (MAPS), it is necessary that O&M costs, exclusive of fuel costs, be developed for the plants. These costs are required in a format which will segregate them into "fixed" and "variable" categories.

Fixed costs are those which occur in a plant and do not vary regardless of the level of operation, provided the plant is maintained in an operating condition. Fixed costs are measured in dollars per kilowatt ($/kW). Variable costs are those which occur only if a plant generates energy and which vary, in total, directly with the energy produced. Variable costs are measured in dollars per megawatt hour ($/MWh).

Two independent approaches were used in developing the coal plant O&M costs. Initially, utility contacts and utility data were the primary source of data to be used. The utility data was analyzed and modified for the specific site, utilities and plant, and the costs presented in Section 3.3.1 of this report were generated. Preliminary review of these results indicated that further work would be required due to the fact that some of the data was "soft" and several assumptions were required to fill the gaps. Consequently, an independent build-up of O&M costs was performed. This was based on vendor equipment data, operational parameters, Ebasco's data files, and engineering judgment. This second O&M cost estimate is that used for analysis and is presented in Section 3.3.2 of this report.

It was not possible to directly compare the details of the APA-developed O&M costs with those developed by Diamond Alaska or the Matanuska Power Project since details of those estimates are not available. However, a brief summary comparison to the Diamond Alaska costs is presented in Section 3.3.3.

Utility-based O&M costs were developed in 1983 dollars and escalated to 1985 dollars (escalation factor of 1.0638). O&M costs based on vendor data and engineering analysis were developed in 1982 dollars and escalated to 1985 dollars (escalation factor of 1.1046). Both used the GNP Implicit Price Deflator.

3.3.1 O&M Cost Development Based on Utility Data

The analysis of data for existing coal-fired power plants fixed and variable O&M costs reviewed units in the lower 48 states, since there are presently no operational coal-fired power plants of this size range in Alaska. The selection criteria was to evaluate plants not only in the 200 MW size range, but also to evaluate plants burning coal with characteristics similar to Alaska coals. It was also considered desirable in the selection process to evaluate coal plants with similar flue gas particulate and sulfur removal equipment.

As can be seen in the attached summary Table 3-12, the plants considered in the evaluation were as follows:

- o Huntington No. 1 (Utah Power & Light)
- o Parish Plant (Houston Power & Light)
- o Southwest Plant (Springfield City Utility)
- o Asbury Plant (Empire District)
- o Dave Johnson (Pacific Power & Light)
- o Hawthorne No. 3 (Kansas City Power & Light)

The differences between coal plants surveyed and the Alaska Power Authority coal plant are discussed below.

3.3.1.1 Plant Staff and Wages

Because of the higher wage rate in Alaska ($37/hr) versus the average in the lower 48 ($26/hr), the total cost of labor is significantly higher in Alaska. In addition, due to the remote location of the

TABLE 3-12

SPECIFIC UTILITY REPORTED DATA
O&M COST ESTIMATE BACKUP 200 MW COAL PLANT
1983 DOLLARS

Operating Characteristics	Utah P&L Huntington #1	Houston P&L Parish Plant	Springfield City Utilities Southwest Plant	Empire District Asbury Plant	Pacific Power and Light D. Johnston Unit #3	Kansas City Power and Light Hawthorne #3	Adjusted Alaska Annual O&M Costs 12/ (1985$)
Plant Rated Capacity (MW)	415 MW	570 MW	415 MW	200 MW	220 MW	235 KW	200 MW
o Coal HHV Btu/lb	11,900	8,600	12,000	11,500	7,800	12,000	7,600
o No. Total Staff	125 5/	100 5/	90 5/	42 5/	90 5/	100 5/	123
o Fixed Labor Costs $/kW/yr	21.74	13.30	16.45	15.92	31.02	32.27	50.35
o Plant Ht. Rate Btu/kWh	9,883	10,400	11,008	10,542	11,101	11,949	10,300
o Sulfur in Fuel (%)	.5	5	3.5	5.4	.45	3.0	0.2
o Flue Gas Desulfurization Maintenance Cost	$ 660,000 1/	$ 500,000 1/	$ 500,000 1/	$ 50,000 2/	$ 630,000 1/	$ 550,000 1/	$ 355,100
o Landfill Disposal Costs	$ 200,000	N/A 3/	N/A 3/	N/A 3/	N/A 3/	N/A 3/	$ 1,750,000
o Chem. Makeup Cost Limestone	$ 330,000	$ 250,000	$ 200,000	$ 200,000	$ 400,000	$ 300,000	$ 1,400,000
o Precipitator & Baghouse	$ 910,000	$1,200,000	$ 700,000	$ 500,000	$1,150,000	$ 900,000	$ 510,500
o Boiler Maint. Costs	$1,100,000	$1,000,000	$ 800,000	$ 625,000	$3,100,000	$ 500,000	$ 856,000
o Coal Handling Equip. Maint.	$ 800,000	$1,030,000	$ 200,000 6,9/	$ 277,000	$ 210,000	$ 200,000 9/	$ 494,000
o Turbine/Gen. Maint. Cost	$ 350,000	$ 400,000	$ 250,000	$ 220,000	$ 380,000	$ 400,000	$ 222,000
o Cooling Tower Maint. Cost	$ 100,000	$ 100,000	$ 80,000	N/A 11/	N/A 11/	N/A 11/	$ 100,000
o Water and Waste Treatment System Costs	$ 300,000	$ 343,000	$ 100,000 10/	$ 140,000 10/	$ 420,000	$ 250,000	$ 175,000
o Lubricant Cost	$ 50,000 7/	$ 50,000 7/	$ 50,000 7/	$ 50,000 7/	$ 80,000 7/	N/A	$ 80,000
o Total Maintenance Cost	$4,800,000 8/	$4,873,000 8/	$2,880,000 8/	$2,062,000	$6,370,000	$3,100,000	$ 5,942,600
o Variable Maintenance Cost ($/MW Hr)	$1.45	$1.07	$.87	$1.29	$3.62	$1.65	$4.51 13/

1/ Costs are annualized average per unit for scrubber, fans, ducts, and breeching on site where multiple units exist.
2/ Costs are annual maintenance estimate for electrostatic precipitator only.
3/ Landfill is onsite with ponding; Haulage charges were reported under $50,000 annually and other costs were not reported.
4/ Bottom ash/FGD sludge sold at $3.50/ton.
5/ Staffing level is per unit average for reported plant total which is higher. Hourly rate averaged $26.00 with fringes.
6/ Cost estimate is per unit average, otherwise reported per unit rating.
7/ Lube oil is for turbine and generator lubrication only; balance of plant excluded.
8/ Individual unit estimate based on multiple units at one site.
9/ Pulverizers are ball mill type.
10/ Boiler and cooling tower water treatment cost only.
11/ Plant has once through cooling from lake at site.
12/ Adjusted O&M cost estimates include Alaska labor rates of $37/hr and transportation costs for each person once per week at $100 roundtrip.
13/ Based on net generation of 1,401,600 MWh at a CF of 80 percent.

plants in Alaska, (central interior or in the Beluga field), staff levels used are higher (123) than in the lower 48. Also, transport to and from the site is included.

3.3.1.2 FGD System Maintenance Costs

The FGD system maintenance costs are a weighted average based on the costs of the five units listed which have scrubbing systems. Although these systems are not identical, it is felt that lower costs for the simpler system to be used in Alaska are offset by location and the need for high efficiency with very low sulfur coal.

3.3.1.3 Landfill Costs

A large majority of the plants surveyed by Harza-Ebasco employ onsite disposal of scrubber sludge and ash in evaporation ponds. Because a majority of the plants are in arid areas of the western United States, evaporation can be counted upon to eliminate water runoff from the disposed sludge and ash.

Recent power plant designs approved by the EPA and state authorities have required a more permanent solution to the scrubber sludge and ash disposal problems. This solution has taken the form of byproduct sale or providing stabilized sludge landfills. Harza-Ebasco developed costs associated with an environmentally acceptable approach to stabilized sludge landfill operations. The concept employed is similar to that utilized at other stabilized sludge landfills in the utility industry. It consists of excavation of a ground area, installation of an impermeable barrier to protect groundwater, and the disposal of a blend of stabilized sludge (a mixture of scrubber sludge, ash, and lime to act as a setting agent), which resembles low grade concrete.

3.3.1.4 Chemical Makeup Costs (Lime and Limestone)

The cost for FGD chemicals is a widely varying cost factor between utilities in the lower 48. As documented in the EPRI Report CS-2916, the costs vary significantly in various parts of the country. Because there is no source of lime in Alaska, Harza-Ebasco developed the costs based upon discussions with Seattle, Washington firms. These costs reflect the high transportation charge for delivery to the Cook Inlet ($190/ton). In comparison, if the power plant were located in Seattle, Washington, the annual cost for the FGD system would be approximately $240,000, rather than the $1,260,000 Alaska estimate.

3.3.1.5 Particulate Removal System Maintenance

The survey showed that a much higher cost is associated with particulate removal system maintenance than the 0.1 to 0.2 mils/kWh initially assumed by the Power Authority. This higher maintenance cost was the subject of review by Harza-Ebasco. The two highest cost plants were discarded and a weighted average of the four remaining was used.

3.3.1.6 Boiler Maintenance Costs

The boiler maintenance costs reflected in the survey conform to the values obtained from boiler manufacturers for their equipment. The wide range of costs are typical of what may result. Therefore, the figure used is the weighted average of the six plants surveyed.

3.3.1.7 Coal-Handling Equipment Maintenance

The costs used in the Harza-Ebasco estimate of coal-handling equipment operation and maintenance reflect data obtained by telephone conversations with coal-handling equipment manufacturers confirming that found during the utility survey. Due to the high moisture, low hargrove grindability, and the extreme problems to be encountered in the freeze thaw cycles of the fuel, the average weighted cost of the six utilities surveyed was doubled for this application.

3.3.1.8 Turbine-Generator Maintenance Costs

The costs used for maintenance of the turbine-generator are derived from the weighted average of the data supplied by the utilities. This estimate compares favorably to that received from equipment manufacturers.

3.3.1.9 Other Costs (Cooling Tower, Water Treatment, and Lubricant Costs)

Cooling Tower

Due to the severe nature of the climate where the cooling tower will operate, it is not felt that lower 48 O&M costs are applicable. Therefore, after review of vendor data, $100,000 per year was allocated for operating and maintaining the tower. This allows for annual partial fill replacement due to freeze damage and normal maintenance.

Water Treatment

The weighted average of the six surveyed utilities costs were used.

Lubricating Oil

Based on review of the utility data, $80,000 per year was allocated for all lube oil replacement.

3.3.2 O&M Costs Development Based on Vendor Data and Engineering Review

3.3.2.1 Basis for Costs

In order to identify and categorize all costs into either fixed or variable categories some basic assumptions were necessary. The costs of all management, engineering, and operations and maintenance staff maintained for the plant may be considered as fixed costs. This is due to the fact that, provided the plant is maintained in a "ready-to-operate" state, the entire staff is required regardless of the level of operation. This staff will perform all of the day-to-day routine tasks necessary to operate and maintain the plant.

All consumable materials costs will be considered as variable costs. This will include chemicals, lime, gasoline, lubricants and oils, and expendable operating items. Although some items may be expended regardless of the level of plant operation, these are a relatively small cost when compared to major variable costs of lime and chemicals and are not worth identifying separately.

The costs of landfilling the wastes created by the plant are treated as variable. Some small portion of the total wastes stream will be fixed. However, the major waste flows will consist of fly ash, bottom ash, and water treatment sludge. All of which will vary directly with the plant load.

Repair, overhaul, and nonperiodic maintenance costs are handled in two ways. Repair or overhaul of minor equipment is assumed to be performed by the utilities permanent staff. The labor costs are included in the staff fixed labor element, and the material costs are included in the variable materials costs. Repair or overhaul of the major systems and equipment is performed by an outside contracted firm and occurs as a function of hours of operation. All of these costs are treated as variable costs.

3.3.2.2 Costs

Plant Staff

The total plant operating staff, not including support personnel, will consist of 122 persons. This will include general plant management, main plant maintenance, operations, outside yard and buildings, and coal system operations. The breakdown of personnel into these categories is shown in Table 3-13. This is a somewhat large staff for this size plant when compared to staffing of similar plants in the contiguous 48 states. There are two main reasons for the higher level of staffing. First, the Alaskan utilities recognize the shortage of equipment manufacturers' support available in Alaska. In response, the utilities perform more intensive maintenance than would otherwise be the case. Secondly, the coal plants will be located at remote sites with employees staying at camps. It is necessary under these conditions to staff at a level which can handle foreseeable emergencies. Additional factors which increase the staff size are extreme weather conditions and intensive operation of the FGDS.

Several utilities with operating power plants were contacted to determine staffing levels. Those utilities, plant names and sizes, and staffing levels are listed below:

Utility	Plant	No. Employed	Capacity
Pacific Power & Light	Wyodek Plant	114	332 MW
Platte River Power Authority	Rawhide Plant	110	250 MW
Basin Electric	Lee Olds Plant	120	219 MW
Louiseville Gas & Electric	Cane Run No. 5	100	176 MW
Springfield City Utilities	Southwest Power Plant	88	196 MW
Sunflower Electric Cooperative	Hayes Plant	150	319 MW

TABLE 3-13

PLANT PERSONNEL BY CATEGORY

General Plant Management	
1	Plant Superintendent
1	General Supervisor
2	Plant Engineers
1	Clerk
1	Secretary/Receptionist
6	Subtotal
Main Plant Maintenance Crew	
12	Electrical Maintenance Supervisors
6	Foremen
12	Mechanical Maintenance (four shifts - three millwrights/shift)
12	General Maintenance Assistants
8	Laborers
1	Engineer
1	Clerk
53	Subtotal
Operations Crew	
4	Shift Supervisors
4	FGD System Operators
4	Generating Operators
4	Boiler Control Operators
4	Assistant Operators
2	Chemical Technicians
22	Subtotal
Outside Yard and Buildings	
1	Supervisor
2	Foremen
6	Electrical Maintenance
4	Coal System Operators
4	Mechanical Maintenance
3	Loader Operators
12	Plant Security Personnel
4	Laborers
4	Central Stores
41	Subtotal
122	TOTAL PLANT PERSONNEL

TABLE 3-13

PLANT PERSONNEL BY CATEGORY (CONTINUED)

Support Personnel

1	Supervisor
8	Cooking
8	Housekeeping
5	Transportation
3	Medical
25	TOTAL SUPPORT PERSONNEL

The average of the utilities listed above is 46 persons for every 100 MW of capacity. However, this is a very misleading indicator because of the high plant staff and administration that is not sensitive to equipment size. This staffing level would result in a staff of 100 for the 217 MW power plant. The staff level of 122 compares favorably with this number when the reasons for a large staff are considered.

In addition to the plant operating and maintenance staff, there will be a support staff necessary to maintain the camp, provide transportation, and give medical attention as needed. This staff will consist of 25 persons as listed in Table 3-13.

The cost for the total staff of 147 persons is $11,120,000 per year in 1982 dollars. This is based on 147 persons working 2,080 hours per year at a average 1982 cost of $36.40 per hour.

Consumable Materials

Lime for the FGDS will be the largest nonfuel consumable materials expense item. Consumption of lime is expected to average 1,900 pounds per hour of full load operation. Based on a capacity factor of 80 percent, approximately 6,650 tons of lime will be consumed per year. There is no readily available source of lime in Alaska. Until a source is developed it will be necessary to assume purchase of lime in the lower 48 states with shipment to Alaska by barge. The estimated delivered cost of lime is $172 per ton in 1982 dollars, which results in an annual cost of $1,143,800 for lime.

Chemical consumption will occur for water purification and for treatment of condensate and circulating water. These costs are broken down into the areas of primary water treatment, demineralization, and chemical addition for the circulatory water system (cooling tower).

Primary water treatment will supply makeup for the potable water system, the circulating water system, and the demineralizers. Total requirements are expected to be approximately 485 gpm. This will consist of 200 gpm for potable water, 225 gpm for circulatory water and 60 gpm for condensate makeup (demineralizers). The cost per gallon of primary treated water is approximately $0.0027. This results in a total annual cost of $607,300 as shown below:

Primary Water Treatment Costs

Potable Water (200 gpm)(60 min/hr)(8,760 hr/yr)($.0027 gal) =	$283,800
Circulating Water (225 gpm)(60 min/hr)(8,760 hr/yr)($.0027 gal)(0.80 cf) =	255,400
Condensate Makeup (60 gpm)(60 min/hr)(8,760 hr/yr)($.0027 gal)(0.80 cf) =	68,100
TOTAL	$607,300

The circulating water system requires chlorine addition during summer months to control growth of algae and other micro-organisms. Additional, chemicals will be added for pH control, antiscaling, and corrosion inhibition. The expected annual cost of these chemicals is $25,000.

Demineralization of primary treated water for condensate makeup will be performed through two 60 gpm demineralizer trains. These will each consume $3,830 in chemicals per year. Additionally, acid and caustic will be added to the condensate system. The total condensate chemical costs are:

Demineralizer (2 trains at $3,830/train/year) =	$ 7,660
Acid and Caustic =	33,000
TOTAL	$40,660

The total for all chemical consumption and water treatment is $672,960.

Costs for lubricants, oils, and gasoline or diesel fall into three categories. These are transportation vehicles, heavy equipment (bulldozers, etc.), and plant equipment (turbine, pumps, etc.). A total of six transportation vehicles were assumed for the plant, there are four pickup trucks, one van, and one bus. Additionally, there will be five pieces of heavy equipment at the plant consisting of two bulldozers, one flatbed truck, one panel truck, and one dump truck. The annual costs of the transportation and heavy equipment including fuel, lubricants, and maintenance materials is listed below:

TRANSPORTATION AND HEAVY EQUIPMENT COSTS

	Item	Unit Cost	Total Cost 1/
4	Pickup Trucks	at $3,000/truck/yr	$12,000
1	Van	at $4,000/yr	4,000
1	Bus	at $8,000/yr	8,000
2	Bulldozers	at $20,000/unit/yr	40,000
1	Flatbed Truck	at $10,000/yr	10,000
1	Panel Truck	at $8,000/yr	8,000
1	Dump Truck	at $10,000/yr	10,000
			$92,000

1/ Cost of lube, oil, fuel, parts, and nonlabor maintenance charges.

Oil and lubricants for the turbine-generator, boiler feedwater pump and turbine, and other equipment are expected to total approximately $50,000 per year as detailed below:

Turbine lube oil (5,000 gal. at $4.00/gal)	$20,000
Other lube oils (2,500 gal. at 4.00/gal)	10,000
Greases and miscellaneous	20,000
TOTAL	$50,000

Solid Waste Disposal

Landfill disposal of solid waste, as previously mentioned, is a variable cost. There are three waste streams to be handled; these are bottom ash, fly ash, and wastewater treatment sludge. The estimated quantities of these to be handled annually are:

Fly ash (includes captured dry scrubber products)	57,650 TPY
Bottom ash	6,050 TPY
Wastewater sludge	2,000 TPY
TOTAL	65,700 TPY

It is expected that landfill costs, either by contract or by the operating utility, will be $25 per ton in 1982 dollars. This is compatible with current costs of landfilling MSW in an EPA approved landfill. The total annual solid waste disposal cost will be $1,642,500.

Repair and Overhaul Costs

As described in section 3.3.2.1, Basis for Costs, repair and overhaul costs for minor equipment is covered elsewhere. This section deals with repair and overhaul (often referred to as replacement and renewal) of major equipment only. This equipment includes the turbine-generator, boiler, flue gas cleaning equipment, and cooling towers. Repair and/or overhaul will be necessary as a result of actual hours of operation of the equipment. These costs are, therefore, considered variable. The actual repair or overhaul is typically performed by the original equipment manufacturer or other specialist under contract.

In each case, original equipment manufacturers were contacted for data regarding overhaul and repair frequency and costs. The vendor data, together with Ebasco's experience, was used to create Tables 3-14 through 3-18, which document the expected costs. Those total annual costs for each major equipment section are:

Turbine-Generator	$246,751
Boiler	1,351,200
Flue Gas Cleaning	
FGDS	40,020
Baghouse	183,667
Cooling Tower	41,384
TOTAL	$1,863,022

Summary

The total costs developed are presented in Table 3-19. The costs are significantly higher than equivalent costs for lower 48 states operating plants, but are within the range of fossil plants nonfuel costs reported by DOE.1/

The areas where costs are higher are in staff costs, consumable materials (lime), and solid waste disposal. The staff costs are significantly higher due to the larger staff size, the remote location of the plant, and the higher Alaskan wage rate. Lime costs are an order of magnitude above lower 48 costs due to the lack of a ready source of lime in Alaska. Solid waste disposal costs are higher because of the plan for dry offsite landfill 48 plants utilize onsite ponds for disposal.

1/ DOE/EIA-0455(82), "Historical Plant Cost and Annual Production Expenses for Selected Electric Plants 1982."

TABLE 3-14

MANUFACTURERS WORKHOURS LABOR AND SPARE PARTS COST ESTIMATE OF ANNUAL OVERHAUL OR REPAIR FOR A 200 MW STEAM TURBINE-GENERATOR

Maintenance Item	Inspection and/or Repair Interval	Manhours Required	Average Crew Size	Shift Required (8 hours)	Labor Cost @ $36/hr	Parts Cost	Total Cost	Annual Cost
Buckets	40,000/5 yr	4,800	20	30	$172,800	0	$172,800	$34,560
Shells	24,000/3 yr	960	12	10	$34,560	0	$34,560	$11,508
Bolting	24,000/3 yr	1,600	10	20	$57,600	$5,000	$62,600	$20,845
Diaphragm	40,000/5 yr	3,200	20	20	$115,200	0	$115,200	$23,040
Valves	40,000/5 yr	640	8	10	$23,040	$80,000	$103,040	$20,608
Lube System	8,000/1 yr	320	4	10	$11,520	$5,000	$16,520	$16,520
Bearings	40,000/5 yr	1,920	12	20	$69,120	$10,000	$79,120	$15,824
H_2 System	8,000/1 yr	128	4	4	$4,608	$30,000	$34,608	$34,600
Meggar Field	40,000/5 yr	256	4	8	$9,216	$2,000	$11,216	$2,240
Field Removal	40,000/5 yr	192	8	3	$6,900	$10,000	$16,900	$3,380
Load Gear	40,000/5 yr	160	10	2	$5,760	0	$5,760	$1,152
EHC Unit	24,000/3 yr	64	4	2	$2,300	$20,000	$22,300	$6,690
Excitation System	8,000/1 yr	64	4	2	$2,300	$35,000	$37,300	$ 37,300
				ESTIMATED AVERAGE ANNUAL TOTAL COST				$246,751

Estimate of manhours, inspection interval, and spark parts cost are suggested estimates by turbine generator manufacturer for scheduled overhaul shutdown in 3-5 year intervals.

SOURCE: General Electric Company and Ebasco 1984.

TABLE 3-15

MANUFACTURERS WORKHOUR LABOR AND MATERIAL COST ESTIMATE
FOR ANNUAL OVERHAUL OR REPAIR OF A 200 MW COAL-FIRED BOILER1/
1983 DOLLARS

Maintenance Item	Inspection and/or Repair Interval (hrs)	Average Manhours Required	Shifts Crew Size	Labor Req'd (8 hr)	Cost @ $36/hr	Materials Cost	Total Cost	Average Annual Cost
Waterwalls	8,000/1 yr	800	10	10	$28,800	$100,000	$129,000	$129,000
Economizer	8,000/1 yr	320	4	10	$10,800	$20,000	$30,800	$30,800
Super Heater Reheater	8,000/1 yr	240	3	10	$100,000	$80,000	$180,000	$180,000
Steam Drum	4,000/6 mo	192	4	5	$140,000	$110,000	$250,000	$500,000
Convection Section	2,000	192	4	6	$20,000	$20,000	$40,000	$160,000
Flyash Removal	2,000	400	10	5	$14,400	$50,000	$64,400	$257,600
Boiler Controls	4,000/6 mo	192	2	12	$7,200	$40,000	$47,200	$94,400
Pulverizer	8,000	600	20	30	$20,800	$60,000	$80,800	$80,800
					ESTIMATED TOTAL AVERAGE ANNUAL COST			$1,351,200

1/ Cost estimate data is based on manufacturers experience with boilers burning low sulfur, high ash, low heating value (7680 BTU/lb), low grindability western type coal.

2499C

TABLE 3-16

ANNUAL OVERHAUL OR REPAIR COST OF BAGHOUSE
200 MW COAL-FIRED PLANT 1/

Maintenance Activity	Maintenance Interval	Total Cost	Annual Cost
Bag Replacement 7,672 bags at $90/bag	48 months	$690,480	172,620
Labor cost @ $36/hr 2 men/8-hr shift per 100 bags		44,188	11,047
TOTAL ANNUAL EXPENSES		$734,668	$183,667

1/ Based upon phone interviews and original equipment quotation by Joy Manufacturing Inc.

TABLE 3-17

COOLING TOWER ANNUAL MAINTENANCE EXPENSES COST ESTIMATE 1/
200 MW COAL-FIRED POWER PLANT

Equipment Description	Annual Costs
Fill Replacement (one section/yr)	$15,000
Gear Reducer	3,200
Subtotal	$18,200
Labor (640 manhour for one section)	$23,040
(1) Gear Reducer 4 (manhour)	144
Subtotal	$23,184
TOTAL ANNUAL COST ESTIMATE	$41,384

1/ Cost estimate obtained from the Marley Cooling Tower Company.

TABLE 3-18

ANNUAL OVERHAUL OR REPAIR COSTS
DRY FLUE GAS DESULFURIZATION SYSTEM
200 MW COAL-FIRED POWER PLANT
1983 DOLLARS

MAINTENANCE ACTIVITIES

System Component	Labor	Total Parts	Annual Avg.
Absorber/Atomizer	$720	$500	$1,220
Wheel Inserts for 2-75 HP Rotary Atomizer Maintenance	720	10,000	17,720
Pumps:			
2 Feedpumps	$2,000	$4,800	$6,800
2 Material Transfer	2,000	4,800	6,800
3 Lime Milk Transfer	2,000	6,000	8,000
Frequency 8,000 hrs			
Total Estimated Maintenance Cost Subtotal			$40,020

1/ Typical costs estimated were provided by Joy Manufacturing Company for a dry scrubbing system.

TABLE 3-19

200 MW COAL-FIRED POWER PLANT
SUMMARY OF O&M COSTS
(1985 DOLLARS)

	Total Cost (in 1,000s)	Unit Cost	
Fixed Costs			
Staff	$12,283	$61.42/kW/yr 1/	
Variable Costs			
Consumable Materials			
Lime	$1,260		
Water Treatment	743		
Vehicles	102		
Lubricants	55		
Waste Disposal	$1,814		
Overhaul and Repair	$2,058		
Total Variable Costs	$6,032	$4.30/MWh 2/	
Total Nonfuel Costs	$18,315	$91.58/kW/yr 1/	$13.06/MWh 2/

1/ Based on net plant capacity of 200 kW.

2/ Based on plant annual generation of 1,402,000 MWh at the design capacity factor of 80 percent

3.3.3 Comparison of APA Coal-Fired Plant O&M Costs to Those Developed by Others

Diamond Alaska's January, 1985 feasibility study for a 140 MW (net) power plant built at Beluga presented both fixed and variable costs on a an annual basis for the plant. Those costs are tabulated below in 1985 dollars:

	Total Annual Cost	Unit Cost 1/
Fixed Costs	$13,000,000	$92.86/kWyr
Variable Costs	$4,500,000	$4.59/MWh

1/ Based on 140 MW (net) and an 80 percent capacity factor.

These costs are substantially higher than the APA O&M estimates, as shown below:

	Fixed Cost		Variable Cost		Total Annual Nonfuel Costs
	Unit Cost	Total Cost	Unit Cost	Total Cost	
APA Estimate	$61.42	$12,283,000	$4.30	$6,032,000	$18,315,000
Diamond Alaska Estimate	$92.86	$13,000,000	$4.59	$4,500,000	$17,500,000

4.0 THE GAS-FIRED CT ALTERNATIVE

4.1 PLANT DESCRIPTION

The CT plant design is based on using three gas-fired simple-cycle CT units, rated by the manufacturer at a nominal ISO output of 80 MW each.

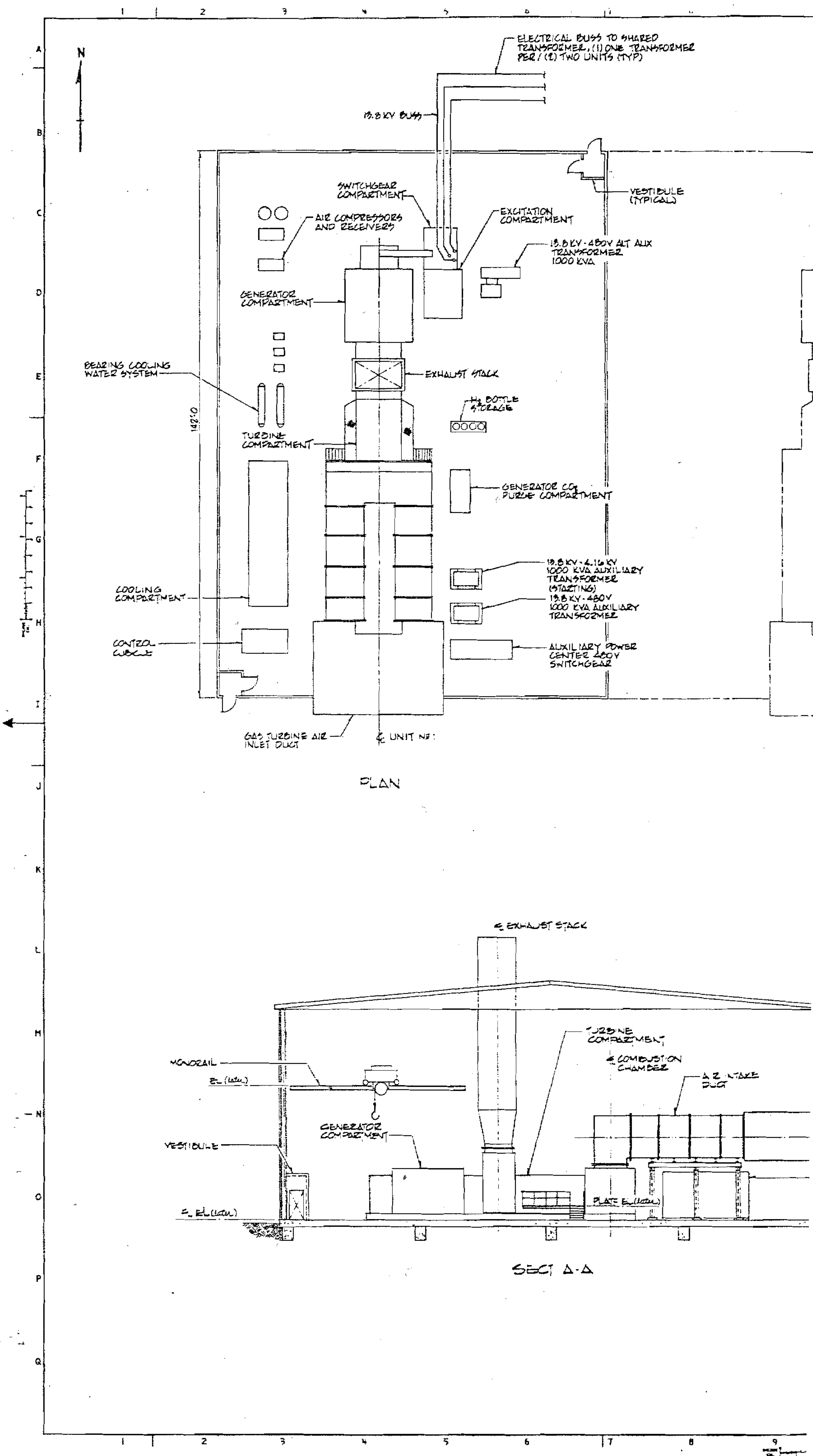
Each CT is a large frame, industrial type with an axial flow multistaged compressor and power turbine on a common shaft. The CT is directly coupled to an electric generator, and can be started, synchronized, and loaded in about one-half hour under normal conditions.

Each CT generator package also includes an inlet air filtration system, fuel system, lubricating oil cooling system, and various minor subsystems, as required, furnished by the manufacturer. Inlet air preheating, using a heat exchanger, will also be necessary. Each unit will utilize water injection for NO_x control.

4.1.1 General Arrangement

The general arrangement of the CT plant is presented in Figure 4-1. The typical plant will consist of three large frame, industrial type CT generators with a gross output of 269 MW electrical.

The power generation facility proper will consist of three CT generators, three separate inlet air filtration systems, starting motors, motor control centers, and lubrication systems to support each CT generator. The electrical interface requirements to the local utility will require separate switchgear compartments complete with generator breaker, potential and current transformers, disconnect link for auxiliary feeder, and a power takeoff. The fuel system will be capable of utilizing natural gas, mixed gas, or liquid petroleum distillate for fuel.


N
ELECTRICAL BUSS TO SHARED TRANSFORMER, (1) ONE TRANSFORMER PER / (2) TWO UNITS (TYP)
13.8 KV BUSS
SWITCHGEAR COMPARTMENT
EXCITATION COMPARTMENT
VESTIBULE (TYPICAL)
AIR COMPRESSORS AND RECEIVERS
13.8 KV - 480V ALT AUX TRANSFORMER 1000 KVA
GENERATOR COMPARTMENT
BEARING COOLING WATER SYSTEM
EXHAUST STACK
H2 BOTTLE STORAGE
142'-0
TURBINE COMPARTMENT
GENERATOR CO2 PURGE COMPARTMENT
13.8 KV - 4.16 KV 1000 KVA AUXILIARY TRANSFORMER (STARTING)
13.8 KV - 480V 1000 KVA AUXILIARY TRANSFORMER
COOLING COMPARTMENT
CONTROL CUBICLE
AUXILIARY POWER CENTER 480V SWITCHGEAR
GAS TURBINE AIR INLET DUCT
℄ UNIT NO:
PLAN
℄ EXHAUST STACK
TURBINE COMPARTMENT
℄ COMBUSTION CHAMBER
AIR INTAKE DUCT
MONORAIL
EL (later)
GENERATOR COMPARTMENT
VESTIBULE
PLATE EL (later)
F. EL (later)
SECT A-A

NO	DATE	REVISION	BY	CH	APPROVED

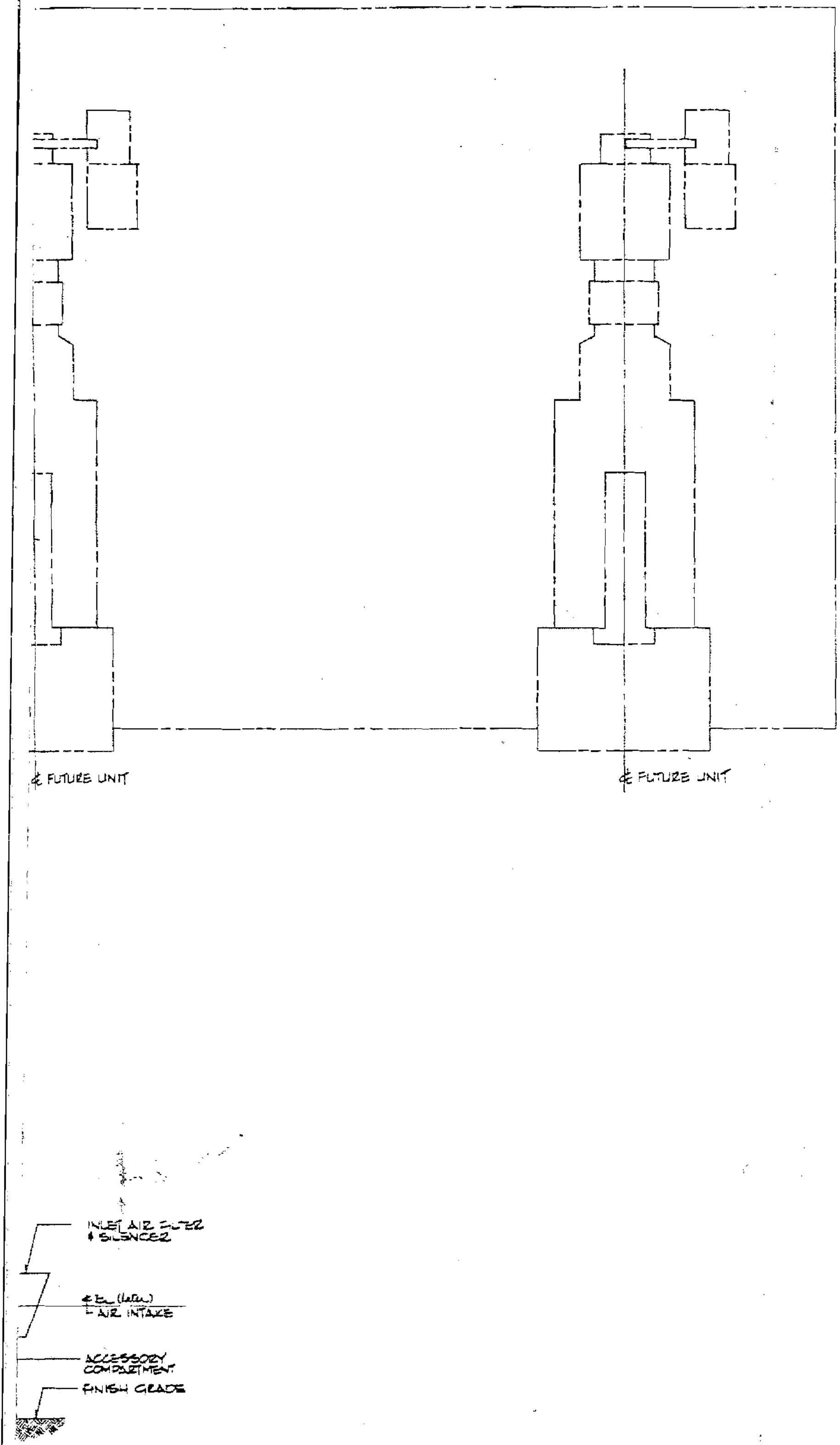


FIGURE 4-1

HARZA-EBASCO
SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

THERMAL ALTERNATIVE
261 MW SIMPLE CYCLE PLANT
GENERAL ARRANGEMENT

SCALE 3/32=1'-0	APPROVED	DATE
DIV. MECHANICAL		APA-2592.140
DR. E.D.JOHNSON		M-GA-001
CH		

4.1.2 Major Plant Components and Functions

4.1.2.1 Turbine-Generator Package

The gas turbine-generators are "packaged" units and, as such, include all auxiliary equipment. The package includes the simple-cycle CT, a totally enclosed generator with water-to-air cooling, 13,800 V 60 Hz, a CT control system consisting of free-standing panels located in the main control room, including the control panel for CT and generator, and the motor control center for unit auxiliary equipment, generator excitation equipment, CT auxiliary equipment, 13.8 kV switchgear, master control panel for overall operation and monitoring, one transformer rated at 1,000 kVA, 13.8/14.6 kV for the 800 hp cranking motor and a second transformer rated at 1,000 kVA, 13.8 kV/480 V for supplying additional auxiliary loads, switchgear and motor control centers, and electrical protection equipment.

Other major electrical equipment includes a 110 MVA step-up transformer with a 13.8 kV low-voltage winding and a 138 kV high-voltage winding. This transformer is connected to the generator switchgear via nonsegregated insulated bus.

4.1.2.2 Plant Auxiliary Systems

The plant auxiliary support systems described in this section represent those necessary to operate a simple-cycle CT facility. These systems include natural gas fuel supply system, water injection system, lubrication system, starting and cooldown systems, accessory drive system, inlet and exhaust systems, waste control systems, and fire protection system.

Natural Gas Fuel System

Clean natural gas is supplied to the nozzles at the combustion chamber by the fuel supply system which consists of the following:

- Fuel gas strainer - mounted off the turbine generator base

- Stainless steel on-base fuel piping with carbon steel flanges

- Combined fuel gas stop and control valves. These valves are located in an explosion proof, vented cabinet on the accessory base.

- Instruments for the gas fuel system, including:

  - Wall mounted, fuel gas inlet pressure gage
  - Line mounted, gas control valve discharge pressure gage
  - Wall mounted, gas stop/ratio valve discharge pressure gage

Water Injection System for NO_x Reduction

The water injection system consists of pumping and metering equipment for supplying water to the combustion system for NO_x abatement. The control system provides NO_x emission control with minimum water injection and minimum degradation in heat rate by modulating the water injection rate proportional to fuel consumption.

Water quality required is:

	Heavy Duty Units
Total dissolved solids	5 ppm maximum
Total trace metals (sodium + potassium + vanadium + lead)	0.5 ppm maximum
pH	6.5 - 7.5

Lubrication System

The turbine, generator, reduction gear, and accessory gear share a common lubrication system. The system is vented to atmosphere and includes the following equipment:

- Main lubrication oil pump (shaft-driven from the accessory gear)
- Oil reservoir integral with the turbine base:
- Full-flow ac motor-driven auxiliary lubrication oil pump with dc emergency backup
- ac motor-driven auxiliary hydraulic oil pump
- Dual lubrication oil finned U-tube heat exchangers
- Dual, full-flow five micron filters
- Stainless steel piping downstream of filters, external to turbine shell
- Instruments for control, indication, and protection of the lubrication oil system

Starting and Cooldown Systems

The starting system includes the drive equipment to bring the unit to self-sustaining speed during the starting cycle. The cooldown system provides uniform cooling of the rotor after shutdown. The turbine is ready to restart any time after it has come to rest. These systems include the following equipment:

- Electric starting motor

- Hydraulic torque converter

- Hydraulically operated, solenoid controlled jaw clutch with automatic disengagement at turbine self-sustaining speed

- Connection to turbine through accessory gear

- Electrohydraulic rotor-turning device with a dc motor-driven pump, mounted on the torque converter (the turbine shaft is turned through a 40 degree arc at approximately three-minute intervals during the cooldown period)

Accessory Drive System

Accessories driven through or driven by the turbine accessory gear drive system are:

- Starting device
- Accessory coupling to the gas turbine compressor
- Lubricating oil pump
- Liquid fuel pump
- Hydraulic oil pump

Inlet and Exhaust Systems

Inlet System - The inlet system arrangement includes the filter compartment, silencing, ducting, trash screens, plenum, support structure, walkways, and ladder.

- Filter Compartment - The filter compartment is elevated above the unit. The compartment contains a self-cleaning filter, access door, lights, and instruments.

- Ducting including transition section is connected to the compartment and directs airflow into the inlet plenum.

- Inlet silencers are included in the ducting to attenuate sounds emitting from the compressor inlet.

- Support structure, walkway, and ladder.

Exhaust System - The exhaust system arrangement includes a plenum and expansion joint. After exiting the last turbine stage, the exhaust gases enter an exhaust diffuser section which terminates in a series of turning vanes directing the gases from an axial to a radial direction into the plenum. The gas then flows to the side through an expansion joint.

Fire Protection System

Due to the cold climate conditions existing for much of the year, fire protection will be based on standard halon systems rather than water systems. Automatic halon systems will be installed for high risk areas, and manual systems will be used for low risk areas. Also, each system selected shall be compatible with any of the specific hazards it is intended to combat.

4.1.3 Plant Operating Parameters

The operation of the 240 MW (ISO) rated simple-cycle plant is greatly affected by site conditions, such as ambient air temperatures. Additionally, the air emissions control methods necessary to meet local requirements will affect the operation. Since these units will be sited at or near sea level, ambient temperature is the single most important variable affecting plant performance.

The standard ISO rating for a turbine is based on factory test block conditions. The ambient air temperature is 59°F, air inlet and exhaust losses for filters, silencers, and ductwork are nominal values, air emission control devices are not utilized and plant support loads are not considered. The ISO rating for the proposed units is shown on Table 4-1.

The power output, heat rate, fuel consumption, air flow, exhaust temperature and unit efficiency are all interrelated and dependent on the ambient site conditions. Ambient air temperature and the corresponding air density, affects the air flow through the compressor and turbine. Since the gas turbines are volumetric devices, cold high-density air increases the mass flow through the machines, which increases the power output and reduces the heat rate.

The method of NO_x emissions control selected for the gas turbine cycles is water injection. The injection of high-pressure water into the combustion zones controls the gas temperatures thereby limiting the formation of NO_x. The net performance effect of water injection is to slightly increase the maximum power output and the heat rate.

The effect of the air inlet and exhaust ductwork, filters, and silencers is to restrict the air flow due to friction losses. Consequently, this inefficiency increases the heat rate and reduces the power output.

The simple-cycle plant performance at various ambient temperature conditions operating at sea level with water injection for NO_x control is presented in Table 4-1.

4.1.3.1 Turbine-Generator Efficiency

The thermal efficiencies reported the net salable power for a given amount of gas turbine fuel energy input expressed as a percentage. All

TABLE 4-1

SIMPLE-CYCLE PERFORMANCE SUMMARY
(3 Combustion Turbines)

	Gross	--------------------	Net 1/2/	--------------------	
Site Ambient	ISO 5/	-23°	30° (Design)	59°	71°
Output, kW Net	80,000	307,500	262,100	237,700	226,600
Heat Rate Btu/kWhr (HHV)	10,660	11,700	12,000	12,200	12,300
Heat Consumption, Btu/hr x 10^6 HHV 3/	852.8	1,203	1,054	967	932
Thermal Efficiency, (HHV) 4/		29%	28%	28%	28%

1/ Auxiliary power assumed at approximately one percent for gas turbine plus fixed plant load.

2/ Water injection was utilized in all net calculations.

3/ Heat inputs are for a single unit and outputs, except ISO, are for three units.

4/ Overall cycle efficiency with auxiliary power losses included.

5/ Gross single unit output rating without corrections for site, plant loads, water injection, or temperature.

inlet and exhaust duct losses, mechanical gearing losses, electric generator losses, and auxiliary plant loads are accounted for. Note that the efficiency changes only slightly with the ambient temperature but that the rating changes significantly.

4.1.3.2 Plant Auxiliary Loads

The simple-cycle facility ratings are net values assuming an overall plant auxiliary load of approximately 2.5 percent. The auxiliary loads fall into two categories: 1) CT auxiliary power and control; and 2) plant loads. The CT loads are approximately one percent of the gross gas turbine output.

Combustion turbine related loads include: lube oil heaters and pumps, cooling fans, water injection pumps, enclosure heaters, and cooling water pumps. The fixed plant load estimated at 4,000 kW consists of: lighting, service water pumps, heating, ventilation and air conditioning equipment, water demineralizer pumps, and maintenance equipment.

4.1.3.3 Net Output and Heat Rates

The net output from the plant consisting of three simple-cycle gas turbines varies from a high of 308 MW at -23°F to a low of 227 MW at 71°F. The net plant output at site conditions of 30°F is 262 MW.

The net plant heat rate is a measure of the input energy to produce a salable kilowatt of electricity. The heat rate is inversely proportioned to the plant efficiency. The heat rates, as all of the plant operating characteristics, are based on the lower heating value of the fuel, which is normally accepted for gas turbine ratings. The fuel lower heating value, or net heating value, does not include the energy required to vaporize the water formed during combustion which is lost in the flue gas. The lower heating value heat rate of 10,900 Btu/kW based on the plant operating at 30°F corresponds to a higher heating value heat rate of 12,000 Btu/kW.

4.2 CAPITAL COST ESTIMATE

4.2.1 Basis of Estimate

Two conceptual estimates for simple-cycle CTs were prepared. Both are for single unit simple-cycle CTs. They differ because one estimate is for a new unit at a completely undeveloped site, while the second estimate is for a new unit or add-on at an existing site. The complete three-unit plant, as described, will consist of one unit corresponding to the first estimate and two add-on units.

The estimates are based on a scope that includes facilities and systems required for self sustaining units. The estimates were prepared in 1983 dollars and escalated to 1985 dollars using Ebasco's Composite Index of Direct Cost for Electric Generating Plants (escalation factor 1.0394). The Composite Index is based on historical data and reflects annual changes in cost of materials, equipment, and labor rates. The conceptual estimates were prepared in the Ebasco Code of Accounts. The estimates are based on a scope that includes the facilities and systems required for self-sustaining units, based on the following:

<u>General</u>

- o Wage rates applicable to Anchorage union agreements south of 63 degrees latitude, including Workmen's Compensation, FICA, and Public Liability Property Damage insurance rates, as calculated by Ebasco.

- o A work week consisting of working ten hours per day, six days per week.

- Sufficient craftsmen available to meet project requirements without labor camps.
- Professional services including engineering, design, related services, and construction management based on a generic plant of comparable size.
- Land and land rights not included.
- Allowance for AFUDC not included.
- Client cost not included.
- Permanent town for plant operating personnel not included.
- Capital cost of gas pipeline not included.
- Operating and maintenance costs not included.
- Contingency included at the rate of 12 percent for material and 15 percent for installation.
- Construction performed on a contract basis.
- Project being exempt from sales/use taxes.
- Labor productivity being "average U.S." with no Alaska adjustment.
- Spare parts and special tools not included.
- Startup costs not included.
- Maintenance machinery, laboratory, and office equipment not included.

Civil

- Clearing or demolition on existing site as necessary for new facility.
- No dewatering of excavated areas is assumed.
- No asphalt or concrete paving is included.
- A 1.5-mile access road is included.
- Fencing perimeter of 75 acres plant site plus interior security fencing as required.
- Simple-cycle building 100 ft x 192 ft x 70 ft eave height.

Mechanical

- General Electric provided a budgetary quotation for an 80 MW G.E. PG7111E gas turbine, and the necessary auxiliary equipment.
- Piping and insulation
- Large bore and small bore piping sizing and quantities are based on historical data from similar units.

Electrical

- Pricing is based on historical data from similar units and in accordance with representative historical inflation indices.
- Indirect construction cost

Indirect Cost

- o Indirect construction cost is priced in accordance with Ebasco experience based on a contract job. Included in indirect costs are:

  - Construction management local hire personnel
  - Casual premium pay (other than scheduled 60-hour week)
  - Construction management automotive equipment
  - Construction management office and expenses
  - Temporary warehouse for prepurchased equipment
  - Road maintenance equipment
  - Offsite unloading and hauling
  - Security guard service
  - Final construction cleanup

- o Testing is assumed to be the contractor's responsibility and witnessed by construction management personnel.

- o Temporary power is assumed to be furnished without cost to contractors.

Professional Services

- o The professional services estimate is based on a standardized workday package for engineering, design, related services, consulting engineering, provided by Ebasco Site Support Engineering (ESSE), and design and construction management services.

4.2.2 Details of Estimate

The capital cost estimates were prepared in a format which presents the total for each line item, as well as the materials costs and installation cost for each item. The summaries of the initial plant and extension plant are presented in Tables 4-2 and 4-3, respectively. The details of these estimates are in Appendix B.

These estimates were used to establish the total cost of a three-unit simple-cycle CT plant, as shown in Table 4-4. The total plant cost was developed by summing the capital costs of the initial CT and two extension units and adding items not included in the capital costs.

Owner's costs are expected to be only one percent of the total direct costs. This is significantly less than for the coal plants, reflecting the simplicity of and shorter construction period for CTs. Startup, spare parts, and special tools are expected to be 0.5 percent of total direct cost. Also, significantly less than for the coal-fired plant. Maintenance equipment, laboratories, offices, and the land for the site are assumed to already exist. This assumption was made by agreement with the major Railbelt utilities that new simple-cycle CT plants will be constructed at existing sites.

4.3 O&M COSTS

In order to utilize the OGP model and MAPS, it is necessary that the plant's O&M costs, exclusive of fuel costs, be developed for input to the models. These costs are required in a format which will segregate them into "Fixed" and "Variable" categories.

Fixed costs are those which occur in a plant and do not vary regardless of the level of operation, provided the plant is maintained in an operating condition. Fixed costs are measured in \$/kW. Variable costs

TABLE 4-2

CAPITAL COST ESTIMATE
SIMPLE-CYCLE CT
INITIAL UNIT
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to Site	1,139	305	834
2.	Earthwork and Piling	695	98	597
4.	Concrete	1,044	238	806
5.	Strct stl/lft Equipment	2,088	1,306	782
6.	Buildings	1,790	695	1,095
7.	Turbine Generator	13,518	12,812	706
10.	Other Mechan Equip	1,005	646	359
12.	Piping	794	271	523
13.	Insulation	134	38	96
14.	Instrumentation	165	103	62
15.	Electrical Equipment	2,836	1,560	1,276
16.	Painting	218	47	171
17.	Off-Site Facilities	2,024	310	1,714
71.	Indirect Const Cost	4,478	0	4,478
72.	Professional Services	2,181	0	2,181
100.	Contingency	4,563	2,211	2,352
99.	Total Project Cost	$38,672	$20,640	$18,032
300.	Total Cost w/o Contingency	34,109	18,429	15,680

TABLE 4-3

CAPITAL COST ESTIMATE
SIMPLE-CYCLE CT
EXTENSION UNIT
(1985 $ in 1,000s)

Account Number	Description	Total Amount	Total Materials	Total Installation
2.	Earthwork and Piling	695	98	597
4.	Concrete	1,044	238	806
5.	Strct stl/Lft Equipment	2,088	1,306	782
6.	Buildings	1,790	695	1,095
7.	Turbine Generator	13,518	12,812	706
10.	Other Mechan Equipment	1,005	646	359
12.	Piping	794	271	523
13.	Insulation	134	38	96
14.	Instrumentation	165	103	62
15.	Electrical Equipment	2,184	1,560	624
16.	Painting	218	47	171
71.	Indirect Const Cost	2,078	0	2,078
72.	Professional Services	1,306	0	1,306
100.	Contingency	3,518	2,138	1,380
99.	Total Project Cost	$30,537	$ 19,952	$ 10,585
300.	Total Cost w/o Contingency	27,019	17,814	9,205

TABLE 4-4

CAPITAL COST SUMMARY
SIMPLE-CYCLE CT POWER PLANT
THREE UNITS
(1985 $ in 1,000s)

Direct Project Costs	
Unit 1 Estimate	$38,672
Unit 2 Estimate	30,537
Unit 3 Estimate	30,537
Subtotal	$99,746
Items Not Included in Estimate	
Owners Cost (at 1% of Direct Project)	$997
Startup, Spare Parts, and Special Tools (0.5% of Direct Project)	499
Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture (Equipment Already Exists)	
Land (Installed at Existing Site)	
Subtotal	$1,496
Project Total Cost	$101,242
Average Cost per kW1/ For 3 unit, 261 MW plant	$386

1/ Based on the three-unit total net rating of 262 MW per unit at design condition of 30°F. Actual ISO rating is 80 MW. Average cost per kW is in whole dollars, not 1,000s.

are those which occur only if a plant generates energy and which varies, in total, directly with the energy produced. Variable costs are measured in $/MWh.

In developing the O&M costs to be used, the initial sources of data for analysis were utility data and vendor data. The data was analyzed and is presented in Section 4.3.1. However, much of the utility data was from the lower 48 states. The Alaskan utilities operate substantially differently from lower 48 utilities, and they are currently in a state of change regarding policy for operating staff and maintenance procedures. For these reasons, an independent engineering build-up of O&M costs was performed. This was based on vendor equipment data, operational parameters, Ebasco's data files, and engineering judgment. This O&M cost estimate is presented in Section 4.3.2 of this report. The two estimates are evaluated in Section 4.3.3.

4.3.1 O&M Cost Estimate Based on Utility Data

The information data base utilized for the simple-cycle CT plant was drawn from: 1) utility information supplied by Alaskan utilities; 2) lower 48 utility information; and 3) CT generator equipment manufacturers. The resulting data is shown in Table 4-5. The utility data O&M costs were developed in 1983 dollars and were escalated in 1985 dollars using the GNP Implicit Price Deflator (escalation factor 1.0638).

utility reported information was not usually
~~It was the primary goal in this data search to qualify information based on a nominal~~ 262 ~~MW power block. However, utility reported information was not usually available for this three-unit power block configuration. Because of these differences,~~ the utility information was averaged and adjusted utilizing the following assumptions:

1. Plant staffing was based on a nominal net power block ratings ranging from 77 MW to 340 MW. At multiple unit sites, plant staff was reported for the CT plant only.

avail for a nominal 262 MW power block configuration. Therefore the

TABLE 4-5

O&M COST ESTIMATE
UTILITY REPORTED DATA
O&M COST ESTIMATE 260 MW NET SIMPLE-CYCLE CT PLANT
1983 $

Cost Description	Arizona Public Service Company - Yuma Plant	Commonwealth Edison Company - Crawford	Florida Power Bartow P.L. - St. Petersburg	Commonwealth Edison Company - Calumet	Anchorage Municipal Power & Light Plant No. 1	APA Plant 1983$	APA Plant 1985$
Plant Rating	157.2 MW	208.0 MW	222.8 MW	297.0 MW	77 MW	261 MW	261 MW
Plant Staff	15	15	20	20	7	25	25
Fixed Labor Cost 1/ $/kW/yr 2/	$5.16	$3.90	$6.31	$4.73	$6.81	$7.17	$7.63
Fuel Cost (Annual)	$2,391,000	$2,037,000	$5,489,000	$2,999,000	$8,130,200	--	--
Plant Heat Rate (Btu/kWh)	14,565	16,587	13,459	16,897	22,000	12,000	12,000
Annual Operating Schedule (Hrs/Yr)	1,800	500	600	600	3,200	7,000	7,000
Consumables Lube, Oil, etc.	$ 50,000	$ 25,000	$ 30,000	$ 45,000	$ 20,000	$148,300	$157,800
Major Overhaul Costs (Annual)	$200,000	$550,000	$650,000	$550,000	$700,000	$575,000	$612,000
Minor Overhaul Costs (Annual)	$185,000	$250,000	$302,700	$250,000	$200,000	$328,100	$349,000
Total Maintenance Cost	$435,000	$825,000	$992,700	$845,000	$920,000	$1,051,400	$1,118,800
O&M Variable Cost ($/MWH)	$1.31	$7.93	$7.42	$4.74	$3.73	$0.57	$0.61

1/ Plant staffing where units are located at large thermal installations was average reported by utility for the specific installation.
2/ Labor cost for Alaskan utility personnel are $36/hr. Lower 48 utility is $26/hr.

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2. Variable maintenance costs were based on the unit run times and power generation levels as estimated by the utilities.

3. Total annual maintenance costs were annualized and spread over the operating period. For example a major overhaul cost scheduled to occur at 60,000 hours was adjusted by the ratio of 8,000/60,000 hours to arrive at a yearly cost.

4.3.1.1 Plant Staff and Wages

Staff levels selected for the Alaska 262 MW plant were based on an average expected staff of 21 personnel to operate and maintain the three-unit plant plus four security personnel. At a total cost of $36.00/hr (1983) and 2,080 hrs/yr/person) the total plant staff of 25 results in an annual staff cost of $1,872,000.

4.3.1.2 Consumable Material Costs

Included in consumable expenses are the material costs of operating and maintaining the demineralized water system for water injection into the gas turbines, and the cost of lubricating oils, greases, gaskets, and minor hardware. The time of actual operation of the lower 48 states utility plants is not as representative of the planned Alaskan plant operation as are the Anchorage Municipal Light and Power (AMLP) Plant No. 1 operating hours. For this reason, the consumable material costs of AMLP were used to generate the planned plant cost land as hours of operation and capacity.

4.3.1.3 Major Overhaul or Annual Maintenance Costs

This cost item includes inspection and major overhaul of the compressor, combustor, entire hot gas path, turbine, and generator in accordance with manufacturer's recommendations. The costs derived for the new plant are well below those reported by AMLP (for older less maintained plants), but are in line with those experienced by other U.S. utilities. The cost of $575,000 per year is based on the average per MW cost of the four lower 48 utilities.

4.3.1.4 Minor Overhaul Costs

The equipment manufacturer's recommend frequent (annual or semi-annual) inspection of the minor equipment, turbine bearings, and other accessible items. These are the annual costs for those inspections and resulting maintenance or repairs. Minor inspection and repairs are performed at prescribed intervals of operating hours (i.e., 3,500, 7,000, etc). As such these costs are a function of operating time. The work performed is also a function of the number of machines to be inspected, repaired, etc. As is expected, the AMLP minor repair costs are higher for the plant size than are the lower 48 utilities minor repair costs. As an estimate of the new plant costs the AMLP costs were used and modified based on the number of machines (four at AMLP Plant No. 1 and three at the APA plant) and the number of operating hours.

4.3.2 O&M Costs Development Based on Vendor Data and Engineering Review

4.3.2.1 Basis for Costs

In order to identify and categorize all costs into either fixed or variable categories some basic assumptions were necessary. The costs of all management, engineering, operations and maintenance staff maintained for the plant may be considered as fixed costs. This is due to the fact that, provided the plant is maintained in a "ready to operate" state, the entire staff is required regardless of the level of operation. This staff will perform all of the day-to-day routine tasks necessary to operate and maintain the plant.

All consumable materials costs will be considered as variable costs. This will include chemicals, gasoline, lubricants, gaskets and oils, and expendable operating items. This is acceptable since it is relatively easy to maintain a CT in a ready-to-operate condition.

Repair, overhaul, and nonperiodic maintenance costs are handled in two ways. Repair or overhaul of minor equipment is assumed to be performed by the utility permanent staff. The labor costs are included in the staff fixed labor element, and the material costs are included in the variable materials costs. Repair or overhaul of the major systems and equipment is performed by an outside firm and occurs as a function of hours of operation. All of these costs are treated as variable costs.

These costs were developed in 1982 dollars and escalated to 1985 using the GNP implicit price deflator (escalation factor of 1.1046).

4.3.2.2 Actual Costs Developed

Plant Staff

The total plant staff will consist of 26 persons. This will include a plant superintendent, operators, and maintenance personnel. The actual "operating" staff will be quite small compared to the maintenance staff. This reflects the fact that all three units can be started, operated, and shut down remotely by a system dispatch center. Should an on-duty operator require assistance, the maintenance personnel will be available. The plant staff is described in Table 4-6.

The simple-cycle CT plants will not be at a remote location and therefore do not require large staff for emergencies or any permanent support facilities.

TABLE 4-6

262 MW (net)
SIMPLE-CYCLE CT PLANT
PLANT STAFF

Superintendent	1
Plant Operators	4
Maintenance Foreman	1
Mechanical Maintenance	4
Electrical Maintenance	4
General Maintenance	9
Security	3
Total Plant	26

Staff sizes for CT plants in the contiguous 48 states were reviewed to determine whether or not the above estimate is consistent. As shown Table 4-7, these plants have smaller staffs than that estimated as necessary for the Alaska plant.

TABLE 4-7

CONTIGUOUS 48 STATES
CT GENERATING PLAN
STAFF SIZE

Utility	Plant	Size (MW)	Number of Employees
Arizona Public Service Co.	Yuma Plant	157.2	15
Commonwealth Edison Co.	Crawford	208	15
Commonwealth Edison Co.	Calumet	297	20
Florida Power Corporation	St. Petersburg	223	20
Florida Power & Light Co.	Lauderdale	821	48
Florida Power Corporation	DeBary	401	23

This data indicates an average plant staff for CT plants of slightly less than seven persons per 100 MW of installed capacity. This would indicate a staff size of 17 or 18 persons for the plant in question.

The staff size of 26 is felt to be consistent with this in view of the fact that the other utility plants average 351 MW in size and probably realize some efficiency of scale for staff size.

The total cost in 1982 dollars, of this staff, is $2,077,500. This is based on 26 persons working 2,195 hours per year at an average wage cost of $36.00 per hour. The additional hours above the standard work-year of 2,080 hours allows for coverage of plant operation with only four shifts.

Consumable Materials

Water treatment for the water injection systems will utilize a regeneration demineralizer system and filters. This system will require regular maintenance and periodic replacement of the demineralizer bed materials and filters. Since the units are to be built at existing plant sites, the assumption is that a potable water system already exists and primary treatment will not be necessary. Demineralized water required per unit is 28 gpm, resulting in a total 84 gpm three-unit requirement. Two 60 gpm demineralizer trains will be utilized to supply the water injection system. The annual cost of bed materials for each train is $3,830 and the cost of acid and caustic is $16,500 per train. This results in a total demineralize materials cost of $40,660 as presented in Table 4-8.

The inlet air filtration system will consist of high efficiency prefilter and an initial separator (dropout) zone. The inertial separator will require cleaning, but not any material replacement. The high efficiency prefilters will require periodic filter cell changeout. Changeout frequency will vary depending on local air quality conditions. It is anticipated that each filter unit will be charged out twice per year for each of the three units. The estimated cost of materials for each filter unit of $8,000 is presented in Table 4-9 resulting in a total annual inlet filter system material cost of $48,000.

TABLE 4-8

MEDIA FILTER CHANGEOUT COST ESTIMATE
FOR A WATER TREATMENT PLANT
MIXED BED REGENERATED UNIT[1]

System Component	Media Change Out Interval	Amount and Cost/Train	Fixed Annual Cost
Sand Filter	2 yrs	12 Ft^3($50/$ft^3$)	$300
Cation Bed	5 yrs	22 Ft^3($100/$ft^3$)	440
Anion Bed	3 yrs	22 Ft^3($260/$ft^3$)	1,910
Mixed Bed	3-5 yrs	7 ft^3 ($116-$260/ft^3)	880
Carbon Filter	2 yrs	12 ft^3 ($50/$ft^3$)	300
			$3,830/Unit
Annual Cost for 2 units			$ 7,660
Sulfuric Acid and Caustic			33,000
	Total Amount		$40,660

TABLE 4-9

SIMPLE-CYCLE CT PLANT
INLET AIR FILTERING SYSTEM
O&M COST ESTIMATE 1/

System Component	Annual Cost
(3) High Efficiency Prefilter (2 filter change/yr) Parts Cost $8,000/filter	$48,000
(3) Labor Cost 3 men at 8 hr each changeout	
TOTAL COSTS	$48,000

1/ Information obtained from Anchorage Municipal Light & Power

Consumption of lubricating oil, grease, and miscellaneous items, such as gaskets and small hardware, is a variable expense. These materials are consumed as a function of operating hours. The largest single usage of lube oil will be the three turbine-generator sets. While the lubricating oil will seldom require changing, oil will be lost from the system through cleaning, leakage past bearing journals, and filter changeout. Makeup for these losses will be in the range of 6,000 gallons per year. With a delivered cost of $400 per gallon, the resultant annual cost for three units is $72,000.

Lubricating oil for other equipment will be minor in comparison to the turbine-generator requirements. These uses are for pumps, motors, fans, and other small equipment. This expense item, coupled with minor hardware items, such as gaskets, nuts and bolts, valve repair parts, etc., are expected to total approximately $5,000 per year for the three-unit plant.

The turbine exhaust system will wear or degrade as a function of hours of unit operation. Acoustical panels, expansion joints, and the turbine exhaust breeching will wear due to temperature, exhaust gas components, and startup and shutdown temperature gradients. The exact number of acoustical panels and expansion joints installed per unit is uncertain until the plant layout is final. It is likely, however, that some of these will require replacement every three to five years. For this reason, an annual variable cost allowance covering these panels and three expansion joints of $45,000 is used. The breakdown of expected costs is shown in Table 4-10.

Waste Disposal

There will be two waste streams from the plant. The first will be sanitary wastes. It is assumed that with modification at the time of construction, the existing site sanitary facilities will be capable of handling/disposing of this stream. The second waste stream is the

TABLE 4-10

SIMPLE-CYCLE CT PLANT
EXHAUST DUCTING O&M COST ESTIMATE 1/

Units	System Description	Variable Annual Cost
(3)	Acoustic Silencing Panels (spares)	$30,000
(3)	Expansion Joints and Duct Breeching (spares)	5,000
	Labor Costs 3 men at 24 hrs	7,776
	Welding Consumables, etc.	1,500
TOTAL COSTS		$44,276

1/ Cost estimate as obtained from General Electric Company for a typical PG 7111E Installation.

effluent from the demineralizer system. Since it is the only waste stream to be dealt with, it will not be worthwhile to provide on-site treatment and disposal. Rather, the effluent will be held in on-site holding tanks for removal by tank car to an off-site treatment facility. Each demineralizer train will produce 200 gallons of backwash waste water per day. This will result in an annual effluent stream of 146,000 gallons per year to be transported, treated and disposed of. The estimated cost for this service is $0.30/gallon for a total annual cost of $43,800.

Repair and Overhaul Costs

As described in Section 4.3.2.1, Basis for Costs, repair and overhaul costs for minor equipment is covered elsewhere. This section deals with repair and overhaul of major equipment only. Repair and/or overhaul will be necessary as a result of actual hours of operation of the equipment. These costs are, therefore, considered variable.

Each complete generating set consisting of turbine, generator, compressor, and combustor is treated as a unit for both minor and major overhaul activities. Further, need for repair of a single component such as the lube oil cooler, will result in an outage of the unit. A listing of the inspections and descriptions of associated repair work is included in Section 4.3.1. This work is normally performed by an outside service contractor, frequently the vendor that supplied the generating units. The average annual costs of the three types of inspections are shown in Table 4-11. The total shown is for a single unit. The three-unit plant total annual repair and overhaul costs will be $715,500.

Table 4-12 presents the total estimated operating and maintenance costs of $7.96/kW/yr for fixed costs and $0.53/MWh for variable costs. The fixed costs are in line with, although they are higher than, the range of fixed costs that exist in the lower 48 states.

TABLE 4-11

MANUFACTURERS MANHOURS LABOR AND SPARE PARTS COST ESTIMATE
FOR A 79 MW ISO RATED SIMPLE-CYCLE CT 1/

Type of Inspection	Inspection Interval (hours)	Manhours Required	Average Crew Size	8-Hr Shifts Required	Labor Cost @ $36/hr	Parts Cost	Total Cost	Average Annual Cost
Combustion	8,000	384	6	8	$13,824	$116,200	$130,000	$130,000
Hot Gas Path or Minor	24,000	1,680	7	30	$60,480	$120,700	$181,200	$60,400
Major Inspection	48,000	2,560	8	40	$92,160	$196,400	$288,560	$48,100
				TOTAL ESTIMATED AVG. ANNUAL COST				$238,500

1/ Manhours, parts cost, crew size and suggested maintenance intervals are approximate manufacturers estimate based on field experience for a typical base loaded CT operating for approximately 8,000 hrs/yr on natural gas fuel.

SOURCE: General Electric Company and Ebasco 1984.

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TABLE 4-12

262 MW SIMPLE-CYCLE CT POWER PLANT
SUMMARY OF O&M COSTS
(1985 $)

	Total Cost (In 1,000s)	Unit Cost
Fixed Costs		
Staff	$2,295	$8.76/kW/yr 1/
Variable		
Consumable Materials		
Water Treatment	$45	
Lubrications	85	
Inlet Air Filtration	53	
Turbine Exhaust	50	
Waste Disposal	$48	
Overhaul and Repair	$790	
Total Variable Cost	$1,071	0.58/MWh 2/
Total Nonfuel Costs	$3,366	$12.90/kW/yr 1/
		1.84/MWh 2/

1/ Based on net plant unit capacity of 262,000 kW.

2/ Based on annual plant generation of 1,829,000 MWh at design capacity capacity factor of 80 percent.

The variable costs are much lower than those found in the lower 48 states. The one single reason for this is the base loading of these units. Review of lower 48 states annual operating hours for CTs[1/] show annual operating hours in the hundreds for most units and in the 1,000 to 5,000 range for all others. The Alaskan units will operate 8,000 hours per year.

4.3.3 Review of Developed Simple-Cycle Plant O&M Costs

The two different estimated O&M costs for a three-unit simple-cycle plant built in Alaska taken from Tables 4-5 and 4-12, are presented below. Also presented are the costs for Chugach Electric Association (CEA) and AMLP.

Utility/Basis	Fixed Unit Cost $/kW/Yr	Variable Unit Cost $/MWh/Yr
APA-based on until-ity data review (Table 4-5)	7.63	0.61
APA-based on engi-nearing review (Table 4-12)	8.76	0.58
CEA (Beluga plant)	11.21	1.40
AMLP (Plant No. 2)	12.79	0.92

The fixed and variable unit costs estimated for the APA plants are significantly lower than those for the Railbelt utilities. The fixed costs for the Railbelt utilities are higher because both plants referred to consist of a number of smaller, older units, and both combined-cycle and simple-cycle units. These plants are representative

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1/ "Historical Plant Costs and Annual Production Expenses for Selected Electric Plants, 1982," DOE/EIA-0455(82).

of the Railbelt plants to be operated in the foreseeable future. This mix of smaller, older plants has higher maintenance and operational staff requirements than is to be expected with new plants consisting of identical units.

Variable costs are a function of the capacity factors of these plants. The APA plants variable costs are based on a capacity factor of 80 percent while the CEA and AMLP plants each operate at a capacity factor of 50 percent. In summary, although the APA estimated O&M costs are lower than the utility reported costs, the differences are justifiable.

The small difference between the two independently estimated O&M costs, 10 percent and 17 percent for fixed and variable, respectively, can be attributed to variance in assumptions and conservatism in the higher estimate. The O&M cost data which will be used is that developed based on engineering review and manufacturer's data - that is \$8.76/kW/yr fixed and \$0.58/MWh variable.

5.0 THE GAS-FIRED, COMBINED-CYCLE PLANT ALTERNATIVE

5.1 PLANT DESCRIPTION

5.1.1 General Arrangement

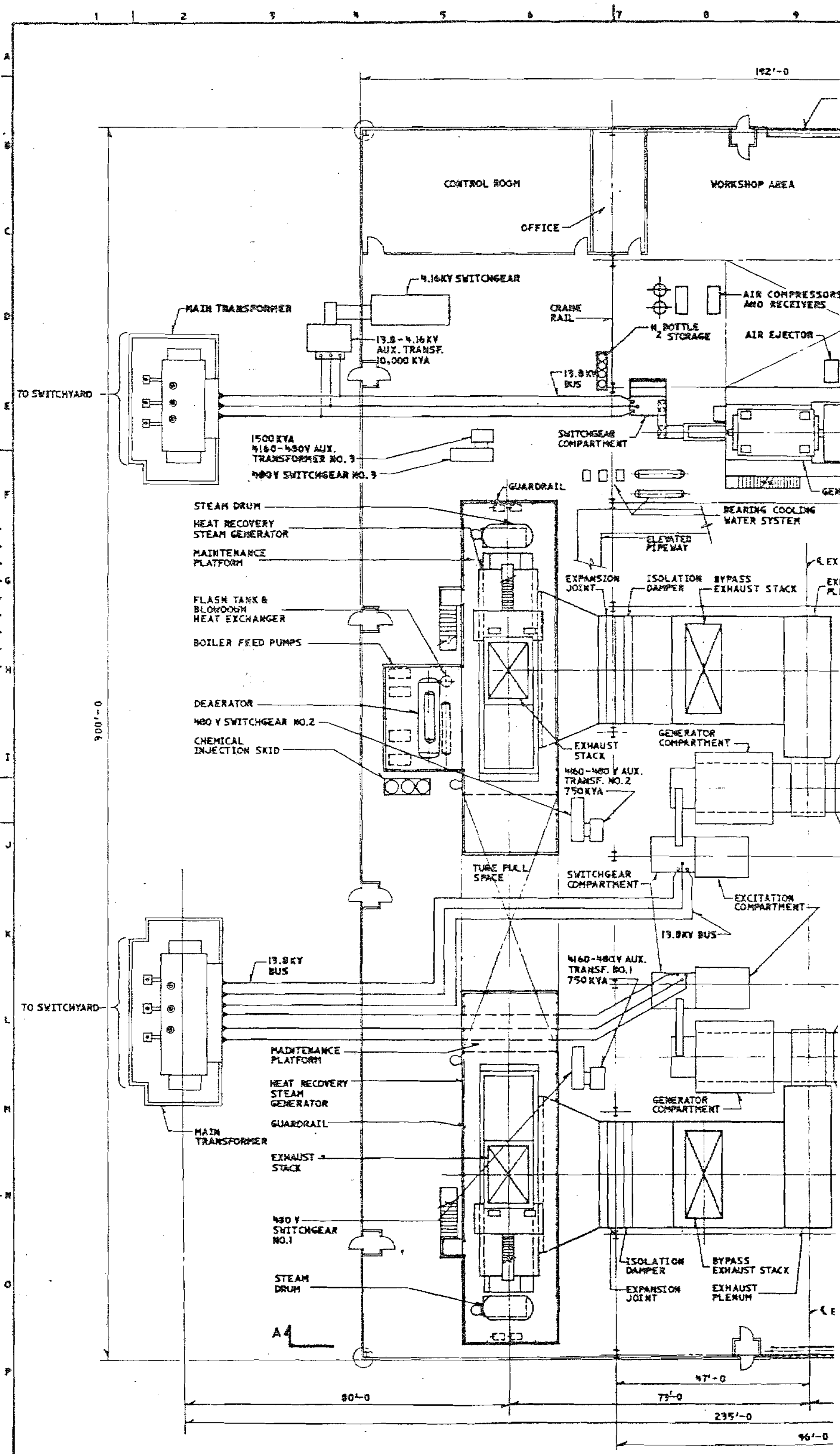
The combined-cycle alternative consists of two sets of two CT generators each exhausting into a waste HRSG. The two HRSGs supply steam to a single steam turbine. Each CT generator will be a large frame industrial type unit identical to the CT utilized for the simple-cycle plant thermal alternative. The CTs, HRSG, and steam turbine-generator set are arranged to minimize hot gas ductwork and steam piping. The arrangement is shown in Figures 5-1 and 5-2.

5.1.2 Description of Major Plant Components and Their Functions

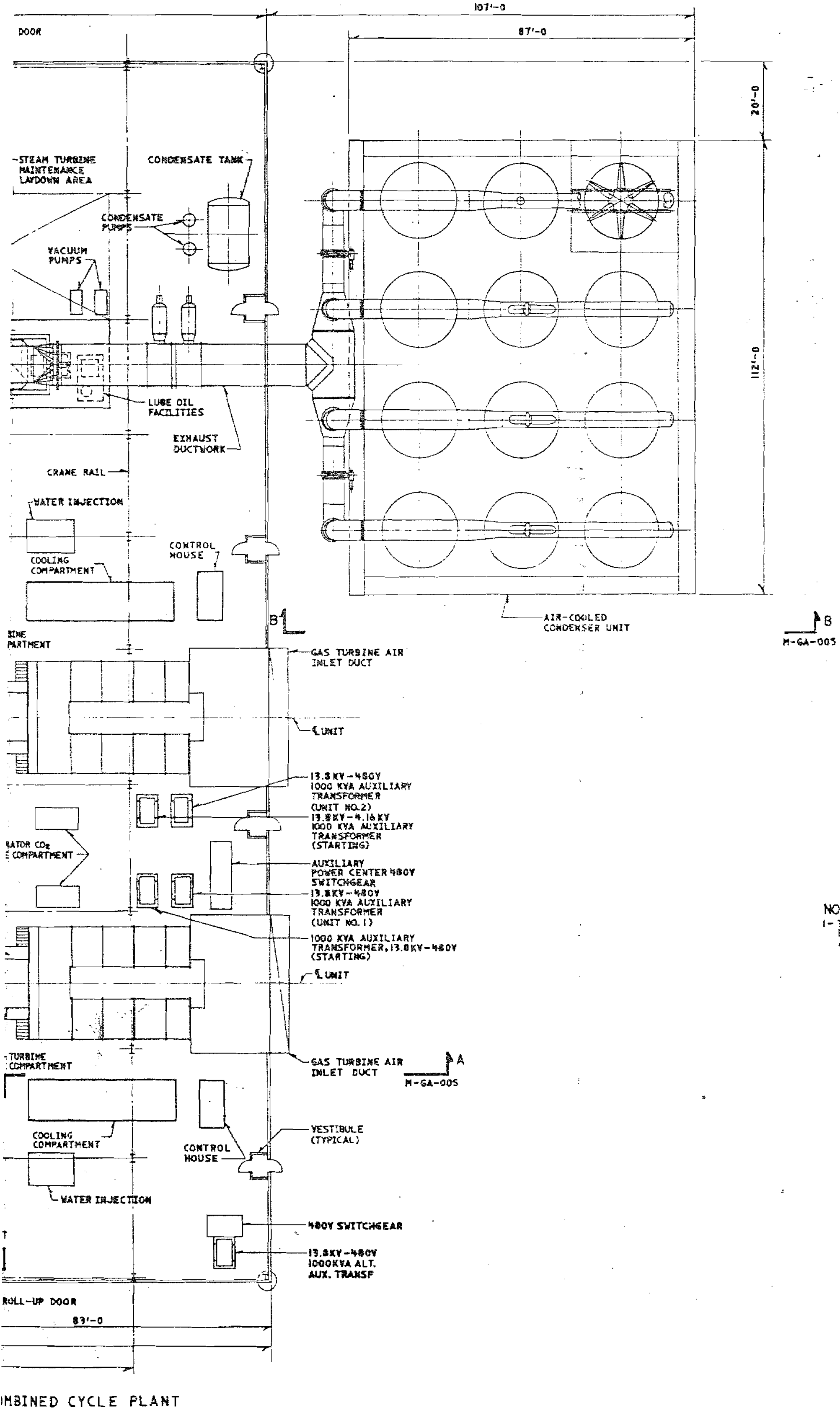
The plant major equipment consists of two sets of CT generators, two HRSGs, one steam turbine-generator, an air-cooled condenser, and a feedwater train.

5.1.2.1 CT Equipment

The two CT generators with attendant equipment will be identical to that described for the simple-cycle power plant in Section 4.1.2. The CT performance is slightly derated due to the increase in exhaust pressure associated with the HRSG. For the actual design conditions at an Alaska site the gross output rating of each CT is approximately 89 MW. The heat balance for the plant is presented in Figure 5-3.



PLAN - 220 MW NOMINAL RATING

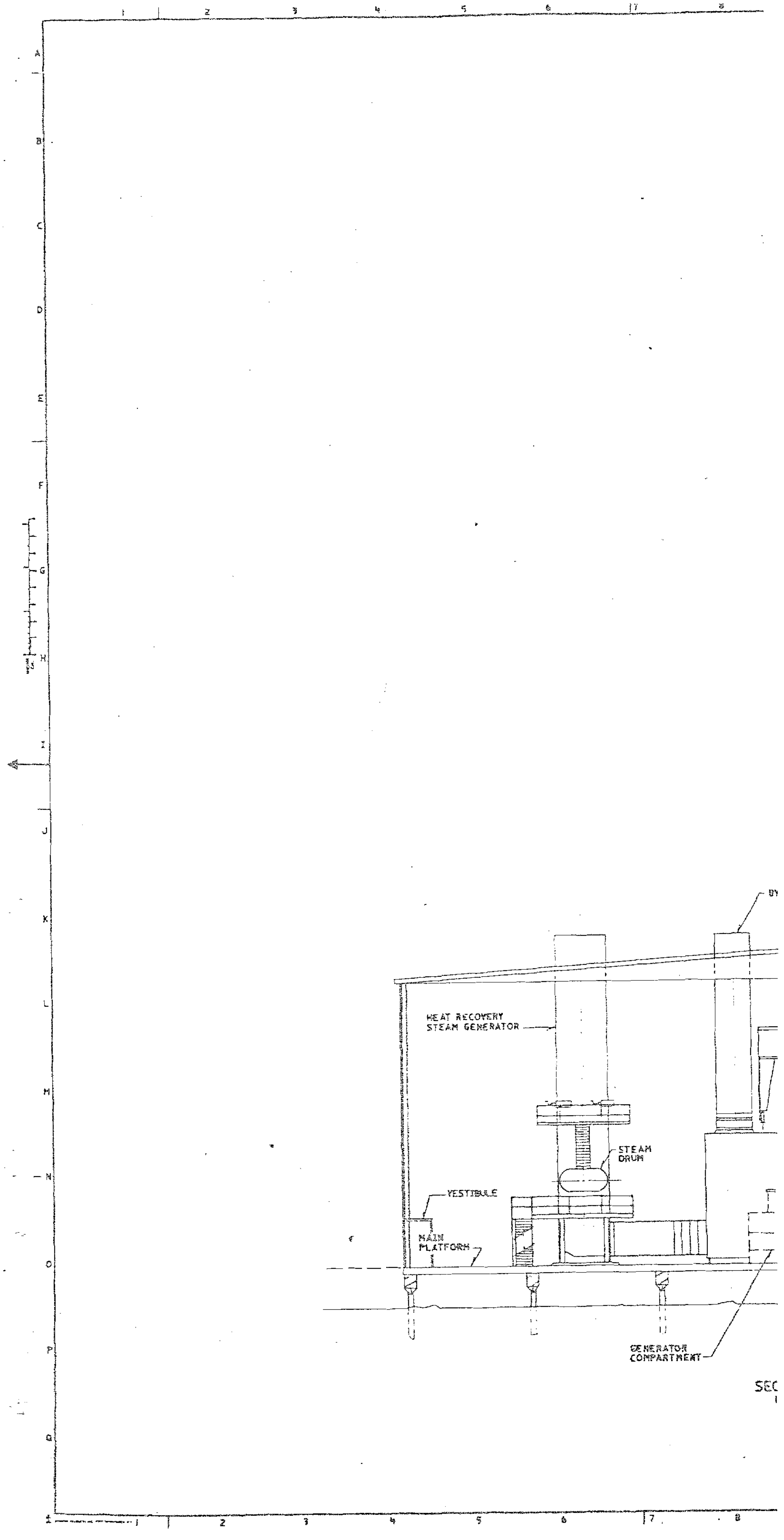


NOTES:

1- THE COMBINED CYCLE PLANT ARRANGEMENT SHOWN IS BASED ON ADDITION OF STEAM TURBINE EQUIPMENT TO A TWO-UNIT SIMPLE CYCLE GAS TURBINE PLANT.

FIGURE 5-1

HARZA-EBASCO SUSITNA JOINT VENTURE	ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT	
THERMAL ALTERNATIVE 230 MW COMBINED CYCLE POWER PLANT GENERAL ARRANGEMENT PLAN	
SCALE: 1/16"=1'-0	APPROVED
DRN MECHANICAL	DATE:
DR	APA 2592.140
CH	M-GA-004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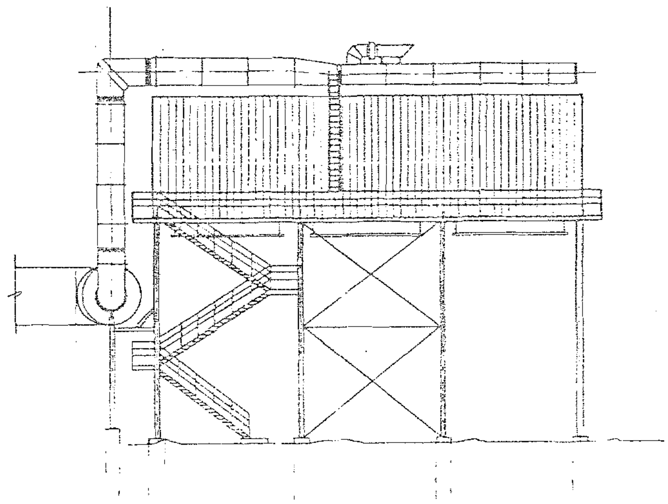
STEAM GENERATOR
STEAM
DRUM
VESTIBULE
MAIN
PLATFORM
GENERATOR
COMPARTMENT
SEC



SECTION - B
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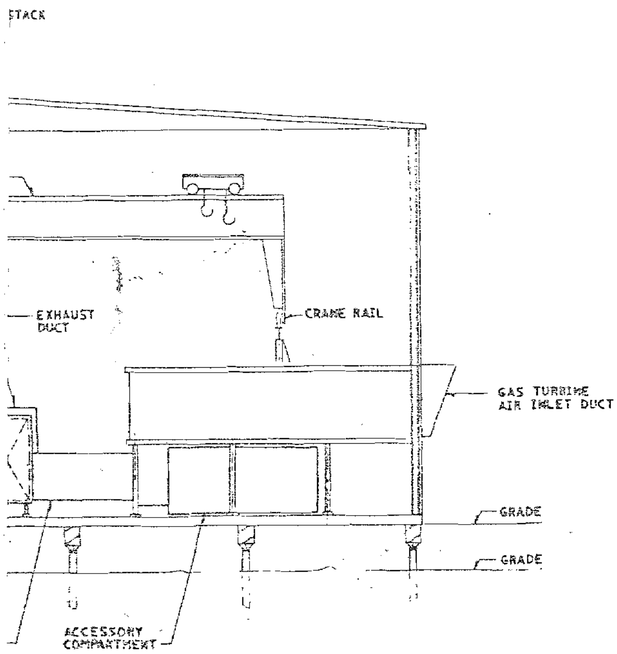


NOTES:
(SEE DRAWING

FIGURE 5-2

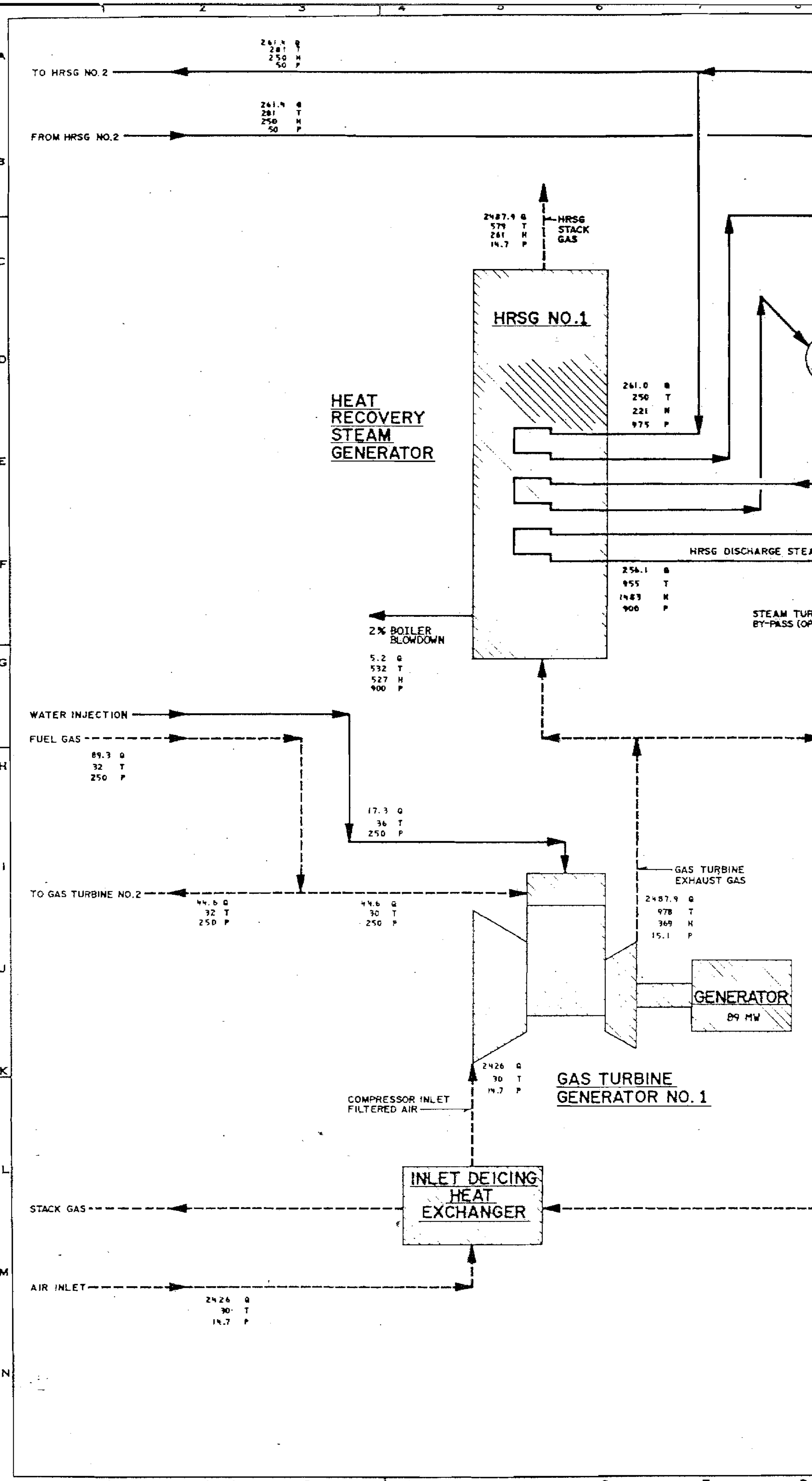
HARZA-EBASCO SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

THERMAL ALTERNATIVE
230 MW COMBINED CYCLE POWER PLANT
GENERAL ARRANGEMENT
SECTIONS

SCALE: 3/32"=1'-0	APPROVED	DATE:
DIV. MECHANICAL		APA 2592.140
DR.		M-GA-005
CH.		


TO HRSG NO.2
261.9 Q
281 T
250 H
50 P
FROM HRSG NO.2
261.9 Q
281 T
250 H
50 P
HRSG STACK GAS
2487.9 Q
579 T
261 H
14.7 P
HRSG NO.1
HEAT RECOVERY STEAM GENERATOR
261.0 Q
250 T
221 H
975 P
256.1 Q
955 T
1483 H
900 P
2% BOILER BLOWDOWN
5.2 Q
532 T
527 H
900 P
WATER INJECTION
FUEL GAS
89.3 Q
32 T
250 P
17.3 Q
36 T
250 P
TO GAS TURBINE NO.2
44.6 Q
32 T
250 P
44.6 Q
30 T
250 P
GAS TURBINE EXHAUST GAS
2487.9 Q
978 T
369 H
15.1 P
GENERATOR
89 MW
2426 Q
30 T
14.7 P
GAS TURBINE GENERATOR NO. 1
COMPRESSOR INLET FILTERED AIR
INLET DEICING HEAT EXCHANGER
STACK GAS
AIR INLET
2426 Q
30 T
14.7 P

5.1.2.2 Steam Cycle Equipment

HRSGs and Ducting

The HRSGs are considered part of the steam plant, although they will be housed together with the CTs in a large common building.

Each HRSG package (one for each gas turbine exhaust) will include the steam generator complete with ductwork from the CT to the steam generator, a bypass damper and bypass stack, and a steam generator exhaust stack. The HRSG performance output of each HRSG shall be 300,000 lbs/hr of 900 psig, 955°F steam when supplied with feedwater at 250°F and 2,417,000 lb/hr of exhaust gas at 973°F. Designed for continuous operation, the HRSGs will include an evaporative section, a superheat section, and an economizer. All steam generator controls will be located in a common area in the central control room.

During startup and other load conditions, the bypass damper may be utilized to provide operational flexibility. By opening the bypass damper and closing the louvered HRSG inlet dampers, the CT exhaust is routed to the stack and does not reach the steam generator.

Steam Turbine and Generator

The steam produced in both HRSGs will be conveyed to a common turbine-generator set. The turbine-generator will be a tandem compound, multistage condensing unit, with one extraction for feedwater heating, mounted on a pedestal with a top exhaust going to the air cooled condenser. Design parameters for the turbine-generator are shown on Table 5-1. The turbine-generator ratings are based on a four-inch HgA or less condenser back pressure which can be maintained anytime ambient outside temperature is 71°F or less. Lower condenser pressures, during cool months, will result in slightly greater power generation.

TABLE 5-1

STEAM TURBINE-GENERATOR UNIT DESIGN PARAMETERS

Turbine Type:	Multistage, single extraction condensing, top exhaust	
Generator Type:	Hydrogen-cooled unit rated 65+ MW at 13.8 kV with 30 psig hydrogen pressure at 10°C	
Performance:	Base Rating	60 MW
	Steam Inlet Pressure	850 psig
	Steam Inlet Temperature	950°F
	Exhaust Pressure	4.0" HgA
	Exhaust Temperature	125°F
	Speed	3,600 rpm
	Steam Rate	510,000 lb/hr
Steam Turbine Generator Features:	Common base mounted with direct-drive couplings. Accessories include multiple inlet control valves, electric hydraulic control system, lubricating oil system with all pumps and heat exchangers for cooling water hook-up, gland seal steam system and generator cooling. Excitation compartment complete with static excitation equipment. Switchgear compartment complete with generator and breaker potential transformers.	

The steam turbine-generator set will be furnished complete with lubricating oil and electrohydraulic control systems, as well as the gland seal system, and the generator cooling and sealing equipment.

In addition to the CT generators, steam generators, and steam turbine, the steam cycle will include the feedwater pumps, condensate pumps, vacuum pumps, deaerator, instrument and service air compressors, motor control centers, and control room.

Waste Heat Rejection

Heat will be rejected from the steam cycle at the outside mounted air-cooled condenser where air flowing across cooling fins absorbs heat condensing the exhausted steam. The condenser will be vertical forced draft with de-icing equipment as suggested by manufacturer. Condensate from the condenser will be pumped first to the condensate storage tank and then to the feedwater heater.

Electrical Equipment

The unit auxiliary transformer is 10 MVA, 13.8/4.16 kV. The secondary winding supplies 4.16 kV switchgear. This 4.16 kV switchgear supplies large motor drives (e.g., boiler feed water) plus three 4.16 kV/480 V transformers with a combined capacity of 3,000 kVA. These transformers supply smaller motors and miscellaneous loads via motor control centers.

Other major electrical equipment includes a 250 MVA transformer with two 13.8 kV windings and one 138 kV winding. This transformer would be connected to the two gas turbine-driven generator switchgear line-ups via a nonsegregated insulated bus duct. The output of the steam turbine-driven generator switchgear would be connected by the same type of bus to a 110 MVA transformer with a 13.8 kV low-voltage winding and a 138 kV high-voltage winding. Other equipment that will be identical to that required for the simple-cycle unit is still applicable.

Miscellaneous Systems

In addition to the potable and service water system, this plant will require makeup water for the steam cycle. To purify the makeup water a demineralizing system will be required.

Blowdown from the HRSGs and waste from the demineralizer and the condensate polisher represent additional waste-handling capacity requirements. These waste streams will require hold-up and treatment prior to discharge in accordance with regulations.

5.1.3 Plant Operating Parameters

The combined-cycle plant is affected by site conditions similar to the simple-cycle plant previously discussed. The turbine performance is affected primarily by the ambient temperature which in turn affect the operation of the steam cycle. As CT output increases with increased air flow at lower ambient temperatures the steam produced in the HRSG also increases. Summary of plant operating parameters is presented below:

PLANT OPERATING PARAMETERS

Fuel Consumption (Full Load)	2,110 x 10^6 Btu/hr
Steam Generation (Full Load)	5.1 x 10^5 lb/hr
Steam Pressures/Temperature	2,400 psia/1,000°F
Gross Generating Capacity	378,300 kW
Station Auxiliary Loads	7,400 kW
Net Generation	229,900 kW
Gross Station Heat Rate at Full Load	8,900 Btu/kWh
Net Station Heat Rate at Full Load	9,200 Btu/kWh
Net Station Rate at 30-Percent Load	12,600 Btu/kWh

The performance of the gas turbine-generator is slightly reduced from that for a simple-cycle configuration due to the higher exhaust pressure of the HRSG. However, the energy lost by the simple cycle in the turbine exhaust is available for the steam cycle.

The ambient site temperatures will also directly affect the performance of the air-cooled condenser selected for this alternative. The performance of an air-cooled condenser improves with ambient temperatures below the design temperature. Lower ambient temperatures lower the turbine back pressure which increases the steam turbine generator output. However, for these calculations, a four-inch HgAbs condenser pressure has been assumed for all ambient temperatures. Actual possible power output will be slightly greater during cooler portions of the year. Table 5-2 shows performance as a function of ambient temperature.

5.1.3.1 Turbine-Generator Efficiency

Similarly to the simple cycle, the combined-cycle thermal efficiencies reported are the percent of net salable power for a given fuel energy input to the gas turbines. All mechanical losses, electrical losses, and auxiliary loads has been deducted from the gross power generated. The energy recovered with the addition of the HRSG and steam turbine accounts for approximately a ten percent increase in the thermal efficiency over the simple cycle, with a predicted net thermal efficiency of 37 percent.

5.1.3.2 Plant Auxiliary Loads

The combined-cycle plant ratings are net values assuming an overall plant auxiliary load of approximately three percent. The auxiliary loads fall into three categories: 1) CT auxiliary power and control, 2) steam cycle loads, and 3) plant loads. The CT auxiliary loads are estimated at approximately one percent of the gas turbine site corrected output. The steam cycle auxiliary loads are estimated at four percent of the steam turbine-generator, and consists of boiler feed pumps, condensate pumps, cooling tower fans, and makeup water treatment equipment. The balance of plant load estimated at 3,300 kW includes plant lighting, heating and cooling, air compressors, and maintenance equipment.

TABLE 5-2

COMBINED-CYCLE PLANT PERFORMANCE SUMMARY
(2 CTs Required)

Site Ambient Temp °F	-23°	-30° (design)	59°	71°
Output kW Net 1/	262,400	229,900	212,600	204,900
Heat Rate Btu/kWh (HHV)	9,200	9,200	9,200	9,200
Heat Consumption x 10^6 Btu/hr	2,430	2,110	1,952	1,881
Thermal Efficiency, (HHV) 3/	37%	37%	37%	37%

1/ Auxiliary power assumed at approximately one percent for gas turbine, four percent steam turbine cycle and fixed plant load.

2/ Water injection was utilized in all set calculations.

3/ Overall cycle efficiency with auxiliary power losses included.

5.1.3.3 Operating Configurations

The combined-cycle configuration may be operated in several other modes, in addition to the full combined cycle. Either gas turbine and associated HRSG may be operated alone with the steam turbine operating at approximately half capacity. The most inefficient operation will be with the steam turbine operating at less than full throttle flow. Also, one or both gas turbines may be operated as simple-cycle machines by bypassing the HRSGs. The heat rates for simple-cycle operation will match those for the simple-cycle alternative and the heat rate for the half capacity combined cycle will approach that of the full combined cycle.

5.1.3.4 Net Output and Heat Rates

The net output from the combined-cycle plant with both gas turbines and steam turbine operating varies from a high of 262 MW at -23°F. to a low of 205 MW at 71°F. The net output at site conditions of 30°F is 230 MW.

The net plant heat rate, based on the fuel higher heating value, for the combined cycle is the same for all ambient temperatures. The heat rate of the gas turbines increases slightly in the combined cycle just as in the simple cycle; however, the incremental heat lost in the gas turbine exhaust at higher ambient temperatures is recovered in the steam cycle which levelizes the net heat rate of the combined cycle. The steam cycle heat rate is more dependent on the type of equipment, operating parameters, and auxiliary loads, and less dependent on ambient temperatures than are the CTs.

5.2 CAPITAL COST ESTIMATE

5.2.1 Basis of Estimate

A single conceptual estimate was prepared for the combined-cycle plant. The complete plant as estimated is for a three-unit, combined-cycle, gas-fired plant. Two of the units are gas-fired CTs, while the third is a steam turbine unit. The configuration and operation of the plant is as described in Section 5.1.

This conceptual estimate is prepared in the Ebasco Code of Accounts, and is presented in Table 5-3. The estimate is for a complete combined cycle facility and excludes owner's cost (including Land and AFUDC). The estimate has a base pricing level of January, 1983 dollars and is escalated to 1985 dollars using Ebasco's Composite Index of Direct Cost for Electric Generating Plants (Escalation factor of 1.0394).

The estimate is based on the following:

1. Wage rates applicable to Anchorage union agreements south of 63 degrees latitude, including Workmen's Compensation, FICA, and Public Liability Property Damage insurance rates, as calculated by Ebasco.

2. A work week consisting of working ten hours per day, six days per week.

3. Sufficient craftsmen available to meet project requirements without labor camps.

4. Professional services including engineering, design, related services, and construction management, based on generic plant of comparable size.

TABLE 5-3

CAPITAL COST ESTIMATE
COMBINED-CYCLE POWER PLANT
(1985 $)

Account Number	Description	Total Amount	Total Materials	Total Installation
1.	Improvements to Site	1,722	434	1,288
2.	Earthwork & Piling	2,043	649	1,394
4.	Concrete	7,217	1,633	5,584
5.	Strct. Stl/Lft Equipment	7,442	4,179	3,263
6.	Buildings	4,941	1,956	2,985
7.	Turbine Generator	37,110	34,861	2,249
8.	Stm Generator & Access	18,181	14,268	3,913
10.	Other Mechan. Equipment	9,634	6,849	2,785
12.	Piping	4,542	2,009	2,533
13.	Insulation	1,141	352	789
14.	Instrumentation	2,117	2,869	248
15.	Electrical Equipment	11,973	5,057	6,916
16.	Painting	912	220	692
17.	Off-Site Facilities	2,044	330	1,714
71.	Indirect Const. Cost	10,567	0	10,567
72.	Professional Services	7,439	0	7,439
300.	Total Cost w/o Contingency	129,025	74,666	54,359
100.	Contingency	17,113	8,960	8,153
99.	Total Project Cost	$ 146,138	$ 83,626	$ 62,512

5. Land and Land Rights not included.

6. Allowance for AFUDC not included.

7. Client cost not included.

8. Permanent town for plant operating personnel not included.

9. Capital cost of gas pipeline not included.

10. O&M costs not included.

11. Contingency included at the rate of 12 percent for material and 15 percent for installation.

12. Construction performed on a contract basis.

13. Project being exempt from sales/use taxes.

14. Labor productivity being "average U.S." with no Alaska adjustment.

15. Spare parts and special tools not included.

16. Startup costs not included.

17. Maintenance machinery, laboratory, and office equipment not included.

Civil (Categories 1, 2, 3, 4, 5, 6, 16, 17, and 18)

Clearing is assumed based on scrub brush and trees up to 25 feet. Some rock excavation is assumed in deep cuts. No dewatering of excavated areas is assumed. Waste would be trucked to disposal on an off-site facility. The capital cost of constructing the off-site facility is not included. No asphalt or concrete paving is included. A 1.5-mile access road is included. Air-cooled condenser used in lieu of cooling tower/circulating water lines.

Mechanical (Categories 7, 8, 9, 10, and 14)

General Electric provided a budgetary quotation for one 227 MW G.E. STAG 207E plant consisting of two MS 7001E gas turbines, two HRSGs, one steam turbine-generator, and the necessary auxiliary equipment. Water treatment system pricing is based on a Illinois Water Treatment Company quotation. GEA Power Cooling Systems Inc. provided budgetary quotation for a direct air cooled condenser system.

Piping and Insulation (Categories 12 and 13)

Large bore and small bore piping sizing and quantities are based on historical data from similar units.

Electrical (Categories 15 and 19)

Pricing is based on historical data from similar units and in accordance with representative historical inflation indices.

Indirect Construction Cost

Indirect construction cost is priced in accordance with Ebasco experience based on a contract job. Included in indirect costs are:

- Construction management local hire personnel
- Casual premium pay (other than scheduled 60-hour week)
- Construction management automotive equipment
- Construction management office and expenses
- Temporary warehouse for prepurchased equipment

- o Road maintenance equipment
- o Ten-mile 25 kV temporary transmission line
- o Offsite unloading and hauling
- o Security guard service
- o Final construction cleanup

Testing is assumed to be the contractor's responsibility and witnessed by construction management personnel. Temporary power is assumed to be furnished without cost to contractors.

Professional Services

The professional services estimate is based on a standardized workday package for engineering, design, related services, consulting engineering, ESSE engineering, and design and construction management Services.

5.2.2 Details of Estimate

The capital cost estimate was prepared in a format identical to that used for the CT plant. The summary of the initial plant cost estimate is presented in Table 5-4. The details of these estimates are in Appendix C.

The total plant cost was developed by summing the capital costs of the CTs and the steam unit and adding items not included in the capital costs.

Owner's costs are expected to be only 1-1/2 percent of the total direct costs. This is significantly less than for the coal plants, reflecting the simplicity and shorter construction period for CTs. Startup, spare parts, and special tools are expected to be 0.75 percent of total direct costs, also significantly less than for the coal-fired plant. Maintenance equipment, laboratories, offices, and the land for the site

TABLE 5-4

CAPITAL COST SUMMARY
COMBINED-CYCLE POWER PLANT
(1985 $ in 1,000s)

Direct Project Costs	$146,138
Items Not Included in Estimate	
Owners Cost (at 1-1/2% of Direct Project)	2,192
Startup, Spare Parts, and Special Tools (at 0.75% of Direct Project)	1,096
Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture (Equipment Already Exists)	0
Land (Installed at Existing Site)	0
Subtotal	$3,288
Project Total Cost	$149,426
Average Cost per kW1/ For 230 MW Plant	$650

1/ Based on the design condition ratings at 30°F for CT ratings. With a gross capacity of 237.3 MW and auxiliary loads of 7,447 kW, the net capacity is 230 MW. Average Cost per kW is presented in whole dollars, not 1,000s.

are assumed to already exist. This assumption was made by agreement with the major Railbelt utilities that new combined-cycle plants will be constructed at existing sites.

5.3 O&M COST ESTIMATE

The combined-cycle plant O&M data, just as the coal plant and CT plant data, will be utilized as input to both the OGP and MAPS models. This data too then must be developed in terms of fixed and variable costs. The cost definitions are identical with those given in Section 4.3 for the simple-cycle plants.

Also like the CT plant, Alaskan utility data, contiguous 48 states utility data, and vendor data were gathered and analyzed. Section 5.3.1 presents the O&M costs developed from analysis of the utility data. Section 5.3.2 presents the results of an independent cost buildup based on vendor data and engineering analysis. The two estimates are compared in Section 5.3.3.

5.3.1 O&M Costs Based on Utility Data

The information data base utilized for the combined-cycle plant was drawn from: 1) utility information supplied by Alaskan utilities; 2) lower 48 utility information; and 3) CT generator equipment manufacturers. All utility costs were received based on 1983 dollars and the results escalated to 1985 using the GNP implicit price deflator (escalation factor of 1.0638). The method of categorizing and adjusting the data for individual utilities for comparison purposes on a uniform basis are discussed below.

The utilities contacted whose combined-cycle plant data was used were:

- Anchorage Municipal Power and Light - Plant No. 2
- Chugach Electric Association - Beluga Plant

- o Houston Light and Power - T. M. Wharton Plant
- o Portland General Electric - Beaver Plant
- o Public Service of Oklahoma - Comanche Station
- o Arizona Public Service - Santan Station

These plants studied vary in size from 160 MW to 500 MW. The comparison of these plants for each line item shown on Table 5-5 is discussed below.

5.3.1.1 Plant Staff and Wages

There are two main differences for the higher labor costs for the Alaska plants, staff size, and wage rates. The average staff size of the lower 48 utilities was approximately 6.5 person per 100 MW of capacity, while the Alaska plants averaged over nine persons per 100 MW. This reflects the higher hours of operation for the Alaska plans and results in a staff of 21. Wage rates for Alaskan personnel are approximately $10 per hour higher than lower 48 states, i.e., $36 versus $26.

5.3.1.2 Water Costs

The plant will consume demineralized water for injection into the two CT and condensate makeup to the steam cycle. The cost of treatment varies from plant to plant as shown in Table 5-5. The reasons for the variance are the quantity of water used and the quality of the raw water to be demineralized, based on 150 gpm demineralization and approximately $0.50 cost per 100 gallons. The expected cost is $315,400.

5.3.1.3 Major Overhaul or Annual Maintenance

The costs of equipment overhaul was derived after review of utility data and original equipment manufacturer's data. These include the two CTs, the HRSGs, steam turbine, and air-cooled condenser. The costs in Table 5-5 are the weighted average of the utility costs.

TABLE 5-5

UTILITY REPORTED DATA
O&M COST ESTIMATE COMBINED-CYCLE PLANT

Cost Description	Anchorage Municipal Plant No. 2	Chugach Electric Beluga Site	Houston Light & Power T.M. Wharton Plant (300 MW)	Portland G.E. Beaver Plant	Pub. Srv. Okla. Comanche Station	Arizona Pub. Srv. Santan Station	Alaska Plant 1983$	Alaska Plant 1985$
Plant Rating (MW)	160 MW	178 MW	300 MW	500 MW	255 MW	289 MW	230 MW 3/	230 MW 3/
Plant Staff 1/	15	17	28	20	20	15	21	21
Fixed Labor 1/ Cost $/kW/yr 2/	$11.59	$10.76	$5.05	$2.16	$4.24	$4.29	$6.86	$7.27
Plant Heat Rate	11,000 BTU/kWh	12,500 BTU/kWh	9,650 BTU/kWh	8,800 BTU/kWh	9,445 BTU/kWh	8,860 BTU/kWh	9,200 BTU/kWh	9,200 BTU/kWh
Operating Schedule Hrs/Yr.	8,000 Hr/Yr	8,000 Hr/Yr	6,500 Hr/Yr	1,000 Hr/Yr	2,000 Hr/Yr	2,000 Hr/Yr	7,000 Hr/Yr	7,000 Hr/Yr
Water Costs (Injected)	$350,820 No	$320,000 Yes	$200,000 Yes	N/A No	$11,680 No	N/A No	$315,400 Yes	$335,500 Yes
Major Overhaul Cost (Annual)	$200,000	$162,500	$500,000	$200,000	$400,000	$450,000	$282,000	$300,000
Minor Overhaul Cost (Annual)	$89,700	$70,000	$200,000	$250,000	$200,000	$300,000	$151,000	$160,000
Consumables Lube, Oil, etc.	$60,000	$80,000	$130,000	$ 90,000	$ 65,000	$110,000	$ 80,000	$ 85,000
Total Maintenance Costs (Annual)	$700,520	$854,500	$1,030,000	$1,080,000	$1,341,680	$1,720,000	$828,400	$880,500
Variable Costs $/MWh	$.55	$.60	$.53	$2.16	$2.63	$2.98	$.51	$0.55

1/ Plant staffing where units are located at large thermal installations was average for combined cycle plant reported by utility for the specific installation.
2/ Lower 48 utility labor costs were 26/hr. All are based on 52 weeks/year, and 40 hour weeks.
3/ 230 MW at ISO translates to 230 MW at 30°F.

5.3.1.4 Consumable Materials

The costs of turbine lube oil, grease, chemicals, and miscellaneous hardware for the plant were estimated based on review of utility data.

5.3.2 O&M Costs Development Based on Vendor Data and Engineering Analysis

5.3.2.1 Basis for Costs

The costs of all management, engineering, operations and maintenance staff maintained for the plant may be considered as fixed costs. This is due to the fact that, provided the plant is maintained in a "ready to operate" state, the entire staff is required regardless of the level of operation. This staff will perform all of the day-to-day routine tasks necessary to operate and maintain the plant.

All consumable materials costs will be considered as variable costs. This will include chemicals, gasoline, lubricants and oils, and expendable operating items.

The costs of disposal of the wastes created by the plant are treated as variable. Some small portion of the total wastes stream will be fixed. However, the major waste flows will consist of water treatment sludge, which will vary directly with the plant load.

Repair, overhaul, and nonperiodic maintenance costs are handled in two ways. Repair or overhaul of minor equipment is assumed to be performed by the utilities permanent staff. The labor costs are included in the staff fixed labor element, and the material costs are included in the variable materials costs. Repair or overhaul of the major systems and equipment is performed by an outside contracted firm and occurs as a function of hours of operation. All of these costs are treated as variable costs.

This set of costs was developed in 1982 dollars and escalated to 1985 dollars using the GNP implicit price deflator (escalation factor of 1.1046).

5.3.2.2 Actual Costs Developed

Plant Staff

The total plant operating staff, not including support personnel, will consist of 35 persons. This will include general plant management, plant maintenance, operations, and security. The breakdown of personnel into these categories is shown below.

230 MW (NET)
COMBINED-CYCLE PLANT
PLANT STAFF

Superintendent	1
Plant Operators	8
Maintenance Foreman	1
Mechanical	5
Electrical	5
General	12
Security	3
Total	35

This is a somewhat large staff for this size plant when compared to staffing of similar plants in the contiguous 48 states. There is one main reason for the higher level of staffing. The Alaskan utilities recognize the shortage of equipment manufacturers' support for their base loaded primary generation plants in Alaska. In response the utilities perform more intensive maintenance than would otherwise be the case.

The annual cost for the staff of 35 persons will be $2,760,000 or $12.00/kW/yr. This is based on a 42-hour work week, 52 weeks per year, at an average wage rate of $36.40 per hour. The 42-hour week is used to accommodate personnel requirements for three-shift operation throughout the year.

Consumable Materials

Costs for consumable items will vary directly with plant generation. Consumable materials for the combined-cycle plant are in two categories, chemicals and materials for water treatment and lubricating oil, grease, and miscellaneous hardware items.

Water treatment will be identical to that described for the CT plant, except that a total system capacity of 120 gpm is required. The average maximum demand will be 28 gpm for each CT, 6 gpm (one percent blowdown makeup), and 5 gpm for margin for the steam system for a total of 111 gpm. Two 60 gpm demineralizer will be able to meet the demand. The costs of operation will be:

Demineralizer (2 trains at $3,830/yr)	$ 7,660
Acid and caustic	33,000
Total	$40,660

Consumption of lubricating oil, grease, and miscellaneous items, such as gaskets and small hardware, is a variable expense. The largest single usage of lube oil will be the three turbine generator sets. While the lubricating oil will seldom require changing, oil will be lost from the system through cleaning, leakage part bearing journals, and filter changeout. Makeup for these losses will be in the range of 6,000 gallons per year for the simple-cycle CTs and 1,000 gallons per year for the steam turbine. With a delivered cost of $4.00 per gallon, the resultant annual cost for three units is $52,000.

Lubricating oil for other equipment will be minor in comparison to the turbine-generator requirements. These uses are for pumps, motors, fans, and other small equipment. This expense item, coupled with minor hardware items, such as gaskets, nuts and bolts, valve repair parts, etc., are expected to total approximately $10,000 per year for the three-unit plant. This is higher than the CT plant, and reflects the fact that maintenance of the steam and feedwater cycles will be more costly than that of a CT.

inertial?

The inlet air filtration system will consist of high efficiency prefilter and an initial separator (dropout) zone. The inertial separator will require cleaning, but not any material replacement. The high efficiency prefilters will require periodic filter cell changeout. Changeout frequency will vary depending on local air quality conditions. It is anticipated that each filter unit will be changed out twice per year for each of the two units. The estimated cost of materials for each filter unit is $8,000 resulting in a total annual inlet filter system material cost of $32,000.

The turbine exhaust system will wear or degrade as a function of hours of unit operation. Acoustical panels, expansion joints, and the turbine exhaust breeching will wear due to temperature, exhaust gas components, and startup and shutdown temperature gradients. The exact number of acoustical panels and expansion joints installed per unit is uncertain until the plant layout is final. It is likely, however, that some of these will require replacement every three to five years. For this reason, an annual variable cost allowance covering these panels and three expansion joints of $30,000 for two gas turbines is used.

Waste Disposal

There will be three waste streams from the plant. The first will be sanitary wastes. It is assumed that with modification at the time of construction, the existing site sanitary facilities will be capable of handling/disposing of this stream. The second and third waste streams are the effluent from the demineralizer system and the boiler blowdown. The effluent will be held on site for treatment. Each demineralizer train will produce 200 gallons of backwash wastewater per day. Boiler blowdown will be approximately 6 gpm and will total as much as 8,640 gallons per day. This will result in planning for a daily effluent stream of 8,840 gallons to be treated and disposed of daily. The estimated cost for this onsite service is $0.03/gallon for a total annual cost of $77,200.

Repair and Overhaul Costs

Annual or periodic repair and overhaul (replacement and renewal) of major equipment will be necessary as a result of actual hours of operation. These costs are therefore considered variable. This work is outside contract work and therefore separate from the labor costs detailed previously. The major equipment included is:

- Two CT generators
- Two HRSGs
- One steam turbine-generator
- One air-cooled condenser

CT Generator

These pieces of equipment will receive identical service as those discussed in Section 4.3.2.2. That is, inspections and overhaul will be performed on each turbine, in accordance with the schedule and costs outlined on Table 4-11. The total annual cost then will be $477,000 for the two CTs.

HRSG

The schedule and costs for maintenance of the waste HRSGs are listed in Table 5-6. The table was developed inclusive of both HRSGs at the plant. The total annual cost is expected to be $157,000.

TABLE 5-6

MANUFACTURERS MANHOURS LABOR AND SPARE PARTS COST ESTIMATE
FOR A WASTE HEAT RECOVERY BOILER STEAM GENERATOR
FOR AN ISO RATED 230 MW COMBINED-CYCLE PLANT 1/

System & Components	Inspection Interval (hrs)	Manhours Required	Average Crew Size	Shift Required 8 hr	Labor Cost @ $36/hr	Parts Cost	Total Cost	Average Annual Cost
Economizer, Evaporator	8,000	48	3	2	$1,800	$5,000	$6,800	$6,800
Steam Drum & Mud Drum	8,000	56	7	1	$2,160	$20,000	$22,160	$22,160
Super Heater	8,000	64	8	1	$2,592	$18,000	$20,000	$20,600
Pumps	720	16	2	1	$216	$3,000	$3,200	$12,800
Valves	1,000	16	2	1	$108	$2,000	$2,110	$16,800
Gauges	1,400	16	2	1	$108	$1,200	$1,300	$8,140
Switches	2,000	16	2	1	$108	$1,200	$1,300	$5,200
Duct Work	4,000	16	2	1	$576	$5,000	$5,580	$11,160
Expansion Joints	720	32	4	1	$1,100	$5,000	$6,100	$24,400
Activators	6,000	16	2	1	$576	$10,000	$10,500	$14,000
Dampers	6,000	32	4	1	$1,152	$10,000	$11,200	$14,900
						TOTAL COST		$156,960

1/ Maintenance inspection intervals, manhours, labor cost and parts cost were based on a natural gas-fired CT operating base load 8,000 hr/yr, with a yearly shutdown for boiler drum inspection and tube side washdown, as reviewed by boiler manufacturers.

SOURCE: Babcock & Wilcox, Foster Wheeler Energy Company, and Ebasco 1984.

Steam Turbine-Generator

The steam turbine-generator has a schedule for overhaul maintenance separate from the CT generator. That schedule and associated costs are presented in Table 5-7. The total annual costs are $56,828.

Air-Cooled Condenser

The fixed costs associated with the plant's air-cooled condenser consist of gearbox changeout, fan blade replacement, and in some instances, motor replacement. The cost estimate for fixed costs is $35,300 as presented in Table 5-8.

Total Overhaul and Repair Costs

The total estimated annual overhaul and repair costs are somewhat higher than for the three-unit, CT plant. This is a direct result of the higher cost of maintaining the combined-cycle plant's steam cycle.

5.3.3 Review of Developed Combined-Cycle Plant O&M Costs

The two independently estimated sets of O&M costs are compared below in 1985 dollars:

Utility/Basis	Fixed Unit Cost	Variable Unit Cost	Total Cost	Total Nonfuel Unit Costs
Based on utility data review (Table 5-5)	$ 7.27/kWyr	$0.55 MWh	$2,553,300	$11.10/kWyr
Based on engineering review (Table 5-9)	$13.26/kWyr	$0.66 MWh	$4,119,000	$17.91/kWyr

The difference in variable unit costs between the two estimates of $0.05/MWh is small and attributed to variations in the assumptions made to arrive at those costs. Fixed costs difference between the two estimates are significant and result directly from the difference in estimated staff size and the small difference of $0.40/hr in estimated average wage rate.

TABLE 5-7

MANUFACTURERS MAINTENANCE COST ESTIMATE FOR A COMBINED-CYCLE PLANT
60 MW STEAM TURBINE AND GENERATOR 1/

System & Components	Inspection Interval (hrs)	Manhours Required	Average Crew Size	Shift Required 8 hr	Labor Cost @ $36/hr	Parts Cost	Total Cost	Average Annual Cost
Shells	24,000	200	8	3	$7,200	0	$7,200	$2,400
Bolting	24,000	120	5	3	$4,320	$5,000	$9,320	$3,100
Diaphragm	24,000	500	10	6	$18,000	0	$18,000	$6,000
Valves	4,000	50	6	1	$1,800	$8,000	$9,800	$19,600
Lube System	4,000	40	5	1	$1,440	$2,000	$3,440	$6,880
Bearings	40,000	240	10	3	$8,640	$15,000	$23,640	$4,728
H_2 System	8,000	45	3	5	$1,620	$8,000	$9,620	$9,620
Meggar Field	40,000	24	3	1	$864	$1,000	$1,864	$372
Field Removal	40,000	240	8	30	$8,640	$10,000	$18,640	$ 3,728
							ESTIMATED AVG. ANNUAL TOTAL COST	$56,828

1/ The turbine generator inspection intervals, manhours, crew size and parts costs are based on Manufacturers field experience for an annualized average cost.

2/ Parts cost are based on normal quantity of consumables, gaskets, etc., zero parts cost was assessed for turbine shells and diaphragms assuming no thermal distortions, cracking etc.

SOURCE: General Electric Company and Ebasco 1984.

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TABLE 5-8

AIR COOLED CONDENSER O&M COST ESTIMATE
FOR 230 MW COMBINED-CYCLE PLANT

	Cost, $
<u>Spare Parts Cost</u>	
Fan Blade	$ 7,000
Gearbox	10,000
Lube Oil	500
Electric Motor	3,000
	$20,500
<u>Maintenance</u>	
Labor-Gearbox Changeout 400 MWh/Gearbox	$14,400
Fan Blade Replacement 8 MWh/fan	288
Clean Fin Tubes 3 MWh/section	108
	$14,796
TOTAL ANNUAL COSTS	$35,296

TABLE 5-9

230 MW COMBINED-CYCLE POWER PLANT
SUMMARY OF O&M COSTS
(1985 $)

	Total Cost (In 1,000s)	Unit Cost
Fixed Costs		
Staff	$3,049	$ 13.26/kW/yr 1/
Variable Costs		
Consumable Materials		
Water Treatment	$45	
Lubrications	68	
Inlet Air Filtration	35	
Turbine Exhaust	33	
Waste Disposal	$85	
Overhaul and Repair	$804	
Total Variable Costs	$1,070	0.66/MWh 2/
Total Nonfuel Costs	$4,119	$17.91/kW/yr 1/
		$2.56/MWh 2/

1/ Based on net plant capacity of 230,000 kW.

2/ Based on annual plant generation of 1,612,000 MWh at the design capacity factor of 80 percent.