DOE/RA/50343-1223
(DE82017060)
Distribution Category UC-90c

NEW ENGLAND ENERGY PARK
FEASIBILITY STUDY FOR ALTERNATIVE
FUELS PRODUCTION
FINAL REPORT

Prepared for the
UNITED STATES DEPARTMENT OF ENERGY

Under Contract No.
DE-FG01-80RA50343

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June 23, 1982

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1. INTRODUCTION

1.1 BACKGROUND

During September, 1979, EG&G, Inc. initiated a study to assess the preliminary financial, technical, and marketing viability of a coal based, medium Btu gas production facility having a multiple product slate and located in New England. The results of this assessment were sufficiently positive to encourage EG&G to perform detailed engineering, economic, financial, market, and environmental feasibility studies. In addition, EG&G obtained a purchase and sale agreement for 4,500 acres of industrially zoned land in the Fall River, Massachusetts, area. In April, 1980, EG&G submitted a proposal under Department of Energy Solicitation Number DE-PA01-80RA50185. The EG&G proposal was entitled, "Proposal to Conduct a Feasibility Study For Alternative Fuels Production at the New England Energy Park, Fall River, Massachusetts." Grant No. DE-FG01-80RA50343 was awarded to EG&G in October of that year and it has been used, together with privately invested funds, to perform a detailed feasibility study.

As the feasibility study progressed, The Brooklyn Union Gas Company and Eastern Gas and Fuel Associates joined the development group as investing participants. Key members of the feasibility study team were: EG&G SynFuels (Project Development); Bechtel Power Corporation (Architect/Engineer); Lehman Brothers Kuhn Loeb, Inc. (Investment Banker); EG&G Environmental Consultants Division (Environmental and Permitting); Van Ness, Feldman, Sutcliffe, Curtis & Levenberg (Legal - PURPA); Temple, Barker & Sloane (Economic and Financial Analysis); Moore and Slater (Public and Community Relations); EG&G Services (Waste Heat Utilization and Project Management Information Systems). At the end of two years of project assessment, the development group remains firmly convinced that New England is the prime area in the United States for rapid development of synthetic fuels. It has an energy economy that is 80 percent dependent on oil, most of it imρ

ported. Prices for energy products have been high for a number of years, contributing to an energy price structure in which synthetic fuel products can compete on a Btu equivalent basis. The New England Energy Park (NEEP) would save approximately 10 million barrels of imported oil annually.

1.2 FEASIBILITY STUDY OBJECTIVES

The overall goal of the feasibility study was to provide a base of engineering, financial, marketing, and environmental analysis which would enable project participants to reach a sound and timely decision on whether or not to proceed with design, construction, and operation of the New England Energy Park.

The specific goals of the study are presented below. These goals are basically those presented to DOE in the feasibility study proposal, but they have been updated throughout the study period to reflect the maturation in both the concept of the project and the activity sequence required to develop a large, complex facility.

1.2.1 Business and Financial Objectives

Business and financial activities were directed toward structuring the necessary financial and contractual arrangements that would support the project during engineering, construction, and commercial operation. Specific objectives were to:

a) Identify potential project participants and the optimal roles for each.

b) Perform cost-of-product analysis under varying assumptions.

c) Complete preliminary economic regulatory analysis for those corporate activities which may be regulated by the Federal Energy Regulatory Commission and other agencies.

d) Develop and implement the financial strategy that can bring the project to fruition, including structure of the initial project entities and preliminary financial commitments.

e) Develop purchase agreements for the sale of electricity to utilities or medium Btu gas to power producing groups.

f) Develop purchase agreements for the sale of methane (SNG) and methanol.

g) Structure the project such that the entire project is not subject to regulation as a public utility.

h) Develop and submit appropriate material to the United States Synthetic Fuels Corporation (SFC) that will provide the basis for the project's request for financial support.

1.2.2 Engineering Objectives

Engineering activities were directed toward providing confidence in the technical viability and the estimated cost of the project. Specific objectives were to:

a) Determine the appropriate level of plant integration under selected entity configurations and identify constraints.

b) Select the coal gasification and downstream process units.

c) Obtain coal gasification data using the same gasification process and coal selected for NEEP.

d) Develop overall plant emission inventories of potential operating cases.

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e) Develop capital and operating cost estimates.

f) Evaluate and select auxiliary (coal handling, air separation, steam generation, gas desulfurization, sulfur recovery, and solid and liquid waste treatment) processes.

g) Prepare detailed process flow diagrams, power plant, major equipment, and packaged unit specifications, plant management and plot plans, and cost estimates.

h) Develop a comprehensive reliability and availability enhancement program to increase the probability that the NEEP facility will operate satisfactorily.

1.2.3 Resource Development Objectives

Feasibility study activities were directed toward the development of coal and water resources for NEEP. Specific objectives were to:

a) Analyze potential coal supply options to ensure reliability and cost of coal.

b) Determine the most advantageous transportation and handling systems for coal from the mines to the NEEP site.

c) Obtain through purchase, lease, or right-of-way grant, the real properties required by the NEEP project.

e) Develop a comprehensive water supply plan for the project, including water source identification and preliminary design of necessary water processing and conveyance to the site.

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1.2.4 Environmental Objectives

Feasibility study objectives were to provide a comprehensive data base from which to assess the environmental, social, and economic impacts associated with NEEP development. Specific objectives were to:

a) Develop an environmental baseline through review of existing data bases and field data collection and monitoring.

b) Perform site geotechnical analysis through test borings to determine soil bearing strength, permeability, and drainage patterns.

c) Determine the permits required during design, construction, and operation phases of NEEP.

d) Develop appropriate data, and prepare Environmental Notification Form and Prevention of Significant Deterioration applications, and initiate preparation of the Environmental Impact Report.

e) Determine the qualitative and quantitative nature of the aquatic biota in and around the site, and assess the potential impacts of site development.

f) Qualitatively determine the plant, mammal, bird, reptile, amphibian, and insect populations in the site area and assess the potential impacts of development.

g) Locate and characterize the site's wetlands and areas that fall within the Massachusetts Wetlands Protection Act.

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h) Determine anticipated waste stream characteristics for solid waste, liquid discharges, air emissions and fugitive emissions to ensure proper design of pollution control systems.

i) Project the social and economic effects of NEEP development and operation on the surrounding community.

j) Develop comprehensive environmental siting criteria for placement of NEEP process plants.

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2. SUMMARY AND CONCLUSIONS

2.1 GENERAL CONCLUSIONS

Although falling oil prices and the generally dismal economic outlook have resulted in many synfuel project cancellations and deferrals, the developers of the New England Energy Park have determined, on the basis of this feasibility study, that a coal based, synthetic fuel facility is environmentally, technically, and politically viable in the New England region. The major area of uncertainty involves the financial/economic issues which relate directly to the construction and operation of a multibillion dollar energy production facility.

The economic issue of product cost versus sale price of product is of paramount importance. For example, to insure economic viability of the NEEP, a 1% differential between the cost of coal and oil is required to maintain both product marketability and minimum revenue for operating expense, debt service and return to equity investors.

The NEEP developers are now reasonably confident that the products produced by the project can be sold to displace foreign oil products. However, despite its ability to displace foreign oil, the project is subject to operating losses in the first years of operation before unit production costs reach stability.

The financial issues that face the NEEP development group center around the risks present in a multibillion dollar pioneer energy production facility and the ability or willingness of the participants to absorb these risks. These risks include market risks (the ability to sell products at a price greater than the cost of production), performance short falls (the ability to maintain a facility on-stream factor equal to or greater than that required to cover production costs), cost growth (the ability to develop and construct the facility within the estimated cost), schedule maintenance (the ability to construct the facility within or near the projected time schedule), and debt service (the ability to issue debt at interest rates that maintain financial viability). NEEP has structured a risk mitigation strategy that addresses all of these factors, but real risks remain, those risks require support from the United States Synthetic Fuels Corporation (SFC) to encourage investors to participate in the project.

2.2 SPECIFIC CONCLUSIONS

2.2.1 Financial Development

The sponsors have evaluated the ability of NEEP to obtain financing in the absence of the SFC's assistance. The sponsors have concluded that private financing of a pioneer synthetic fuels plant such as NEEP is not possible without SFC assistance. There are currently a number of potential sponsors willing to devote substantial management time and engineering effort to NEEP, but unwilling to make any formal commitment to the project until it is chosen for Phase II consideration by the SFC. Assuming NEEP is chosen for Phase II, these potential sponsors have indicated an interest in participating in NEEP.

2.2.2 Marketing

Since the initiation of the feasibility study, a third product, methane, has been added to the product slate. This addition provides significant increase in operating flexibility to the facility as well as broadening the market for NEEP products, at minimum incremental cost. The products of NEEP are electric power, methanol, and methane.

Because power is usually sold under long-term contracts and because it is the highest value product that can be produced by the NEEP, it is the financial anchor for the project. New

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England, the market into which the power will be sold, has the most integrated power pool in the United States. The New England Power Pool (NEPOOL), with total capacity of 15,000 megawatts (MW), is a cooperative arrangement among New England utilities that has evolved over many years. NEPOOL operates in much the same way as a single utility would, with dispatch accomplished centrally under the principle of least cost generation; NEEP would operate as a NEPOOL unit.

The proposed marketing arrangements have been designed to protect the nonregulated status of the New England Energy Park. Although methane and power are being sold into regulated markets, contractual arrangements are being designed to insulate non-utility sponsors from regulation.

Contracts are being pursued for the sale of baseload power and the sale of the full production of methane in the winter months and methanol in the summer months. Operational considerations, particularly reliability, indicate that the Integrated Gasifier Combined Cycle ("IGCC") train is best run in a baseload condition. The SNG and methanol downstream units are capable of absorbing the operational swings.

2.2.3 Environmental

The NEEP Environmental Program, which was structured to obtain data essential in designing and siting the facility, designing and routing the rail, utility and road corridors, and in designing and siting the marine terminal, pier, and ocean outfall, is 98% complete. To date, no environmental issues have surfaced which would pose a serious constraint or delay for the Energy Park project.

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The air quality monitoring program has been completed and impact analysis performed. The PSD application (the PSD permit is the longest lead time permit) has been submitted to Environmental Protection Agency (Region I). NEEP emissions of SO_2 (full increment available), NO_2, and CO meet all applicable National Ambient Air Quality Standards.

Field baseline investigations have been completed for geohydrology, water quality, and terrestrial ecology and wetlands. A noise level analysis for the access corridor has been completed.

2.2.4 Permitting

The permitting program is on its original schedule. No developments have occurred which have caused the permitting and construction schedules to be altered.

A Letter of Intent to file for a Section 404 permit from the U.S. Army Corps of Engineers has been sent. This letter will require an official determination as to the applicability of NEPA with regard to anticipated Corps of Engineers action. The Corps has referred the matter to their Washington headquarters and to the President's Council of Environmental quality for a decision on whether an EIS will be required, and if required, which federal agency will be the lead. On June 10 NEEP was unofficially informed that the U.S. EPA will be designated by CEQ to prepare the EIS. This will be formalized in the next few weeks.

The Massachusetts Environmental Policy Act (MEPA) process was initiated at the end of March, 1982. Scoping sessions were held with all regulatory officials and interested persons in Boston and Fall River, Massachusetts, on May 4, 1982. The scope will be finalized on June 25.

The Governor of Massachusetts has provided a mechanism to expedite all regulatory licensing, and related government agency activities related to NEEP through the Massachusetts Energy Facility Siting Council. Federal agency input to the state MEPA process is being coordinated by the U.S. Corps of Engineers. Both federal and state agencies have agreed to the use of a single EIS/EIR document, which will provide for an efficient regulatory review of the project.

2.2.5 Engineering

The engineering feasibility study was completed during May, 1982. The engineers have concluded that the Texaco gasification system in the NEEP multiproduct facility configuration represents the best technology choice for this project, given its New England location. The advantages of high throughput and conversion efficiency, minimal waste effluent, low compression costs, low coal dust hazards, low gas processing equipment costs, and flexibility of feedstock coals balance the technical risks which have been identified. The engineers have identified the technical risk of the project as operating risk due to limited experience with the Texaco partial oxidation process operating on a coal feedstock at a commercial scale. The major elements of operating risk are coal grinding and slurry preparation at the scale envisioned, scaleup of the gasifier size to the NEEP 1200 T/day unit, and removal of slag from the radiant wasteheat boiler. Acid gas removal, sulfur removal and tail gas treating are not expected to be elements of technical risk since they have been commercially operated at the scale envisioned. Similarly, the downstream methanol synthesis, methanation, and power production facilities are in commercial operation at the design size. A detailed description of the plant design, emissions data and startup and operating analysis were prepared. In addition, detailed engineers' drawings were developed.

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2.2.6 Cost Estimate

Design work was progressed sufficiently to allow reliable cost estimation. The capital cost of the plant based on the engineering design is $1,987.9 million (1981 dollars), including direct field costs, distributables, engineering and home office fee, and a contingency specific to each capital line item. Capital cost estimates have been provided in Section 6.2. The complete summary cost estimate (in billions of current dollars) is:

Construction cost estimate	$2.0
Inflation of construction costs	0.8
Interest during construction	0.6
Initial working capital deficits	0.4
Total estimated project costs	$3.8

2.2.7 Local and Regional Support

There was an early recognition of the need to ensure that the project would be accepted in the local and regional area. Acceptance must be on both the political and individual levels. Significant effort was expended during the feasibility study to educate the surrounding communities as to the scope and impacts (both negative and positive) of the proposed NEEP. The project was generally well-received. Favorable political support was obtained from both the local and state levels.

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3. PROJECT DESCRIPTION

3.1 INTRODUCTION

The New England Energy Park (NEEP) is located on a 1900-acre site in Fall River, Massachusetts. The 1900 acres are part of a 4500-acre property that EG&G has under a purchase option agreement. Because portions of this undeveloped 4500-acre property, which has been rezoned for heavy industry, bounds the 1900-acre NEEP site, it allows the nearby sparsely populated areas to be buffered by use of natural features.

The New England Energy Park project integrates the operation of four basic plants: a gasification plant, electric power plant, a methane synthesis plant (SNG) and a methanol plant. The gasification plant gasifies approximately 3.5* million tons/year of high sulfur eastern Appalachian bituminous coal and produces 55 trillion Btu/year of medium Btu (285 Btu/standard cubic foot) gas. The medium Btu gas is then used to feed a combined cycle electric power plant with a net power output of 550MW, a methanol synthesis plant with an output of 50 MM SCFD, and a 2500 ton/day methanol plant. The flow diagram for the NEEP coal handling and gasification and cleanup systems is shown in Figure 3-1.

Feedstocks required for the project included 10,500 tons/day* of coal and 12-15 million gallons/day of water.

Incorporation of multiple products -- SNG, methanol and electric power -- into the NEEP project has several advantages over a single product-only project: 1) gasifier capital is more effectively used

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* Actual quantity of coal consumed depends upon heating value of coal purchased.

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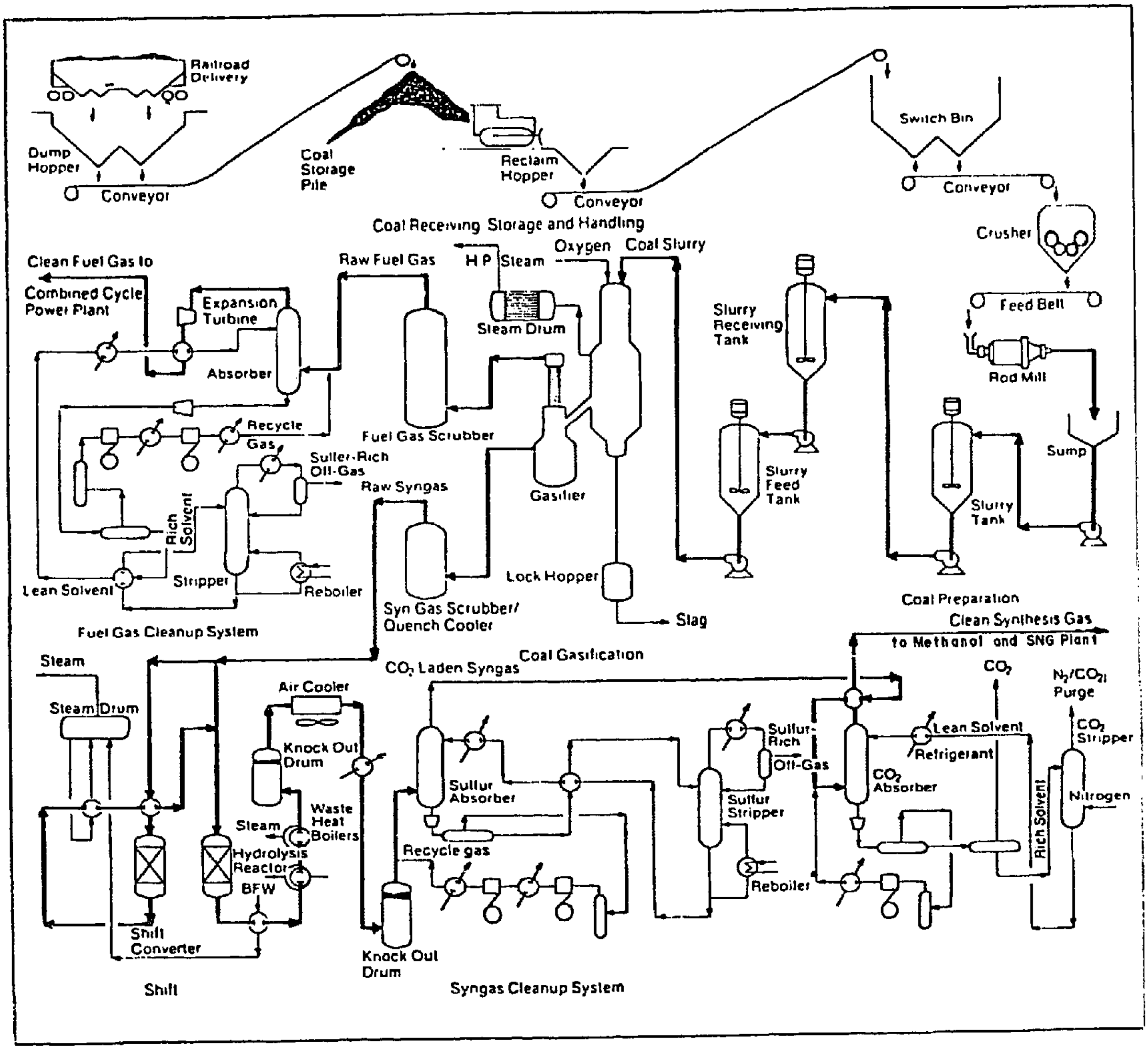

Figure 3-1

NEEP PROCESS DIAGRAM

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because of the higher on-stream factor; 2) methanol production provides a storable liquid fuel that can be used for electric power peaking turbine fuel, transportation fuel or extender, or conversion to other liquid products; 3) methane can be marked during the period of premium rates, and 4) the multiple-product capability takes maximum advantage of economy of scale of the gasification plant.

The project, as it develops, will also attract industries that can use facility byproducts such as low pressure steam, separated gases (carbon dioxide, nitrogen, argon), and hot water.

3.2 OPERATING CAPABILITY/OUTPUT

3.2.1 Gas Production.

The NEEP gas production unit consists of eight gasifiers, one of which is a spare, with associated process systems that allow for independent module operation. Coal and oxygen are fed to each gasifier at a rate of 54.7 tons/hour and 44.3 tons/hour, respectively. The hot raw gas produced from each gasifier (9.1×10^8 Btu/hour or 7.25×10^9 Btu/hour total) is passed through the radiant boilers and split into two streams. The quantities in each stream can be varied depending on the desired amounts of electric power and methanol production. In the base case analysis, two-thirds of the raw gas will be processed as fuel gas and the remainder will be used as methanol synthesis feedstock.

3.2.2 Electric Power Production.

All electric power production equipment is conventional state-of-the-art gas turbine combined-cycle technology. The five gas turbines, consuming about 108 billion Btu per day of medium Btu gas, are connected to five heat recovery steam generators. A single steam-turbine generator is also employed. The combined-cycle power plant has a nameplate rating of 645 MW.

After providing the energy needed by the process plant, the net output is 550 MW in normal operation mode, and is essentially independent of ambient temperature, if fuel-restricted. If supplemental fuel (medium Btu gas or methanol) is provided, the maximum possible output is a function of ambient temperature unless limited by installed generator capacity.

3.2.3 Methanol and Methane (SNG) Production.

Under the nominal operational mode up to two-thirds of the raw gas stream from the gasifier can be used to produce methanol and SNG.

A shift reactor, a hydrolysis reactor, and gas removal stages are employed to produce purified synthesis gas. The shifted and purified synthesis gas is compressed to 750 psig and combined with the recycle gas and delivered to the methanol synthesis unit. Condensed crude methanol from the methanol synthesis unit is sent to the purification unit.

Purified synthesis gas is converted to SNG utilizing the Cono-Meth process.

3.2.4 Product Mix

The flexibility of the NEEP process design allows for the production of electric energy, fuel, and related products at levels which could vary over time to meet changing regional energy requirements or pricing structures. Incorporation of multiple products, methanol, methane, and electric power, into the NEEP project has allowed for significant operational flexibility.

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Engineering design work for the process and power plant developed to date have assumed base-load operation with an overall average operating capacity factor of 90 percent for all parts of the plant, including power generation. Nevertheless, the plant's ability to operate at variable production rates, as well as with load balancing between power, methanol, and methane production is briefly discussed below.

3.2.5 Cogeneration

Cogeneration can be considered to fall into two categories at NEEP, cogeneration between major plant facilities within the NEEP plant proper and between NEEP and nearby industrial consumers of heat energy. The fundamental cogeneration principle is that overall fuel energy utilization in a turbine cycle increases when steam is extracted from low pressure turbine stages to be used for process heat. The improved overall efficiency effect increases as the extraction takeoff point decreases in pressure. Simply, as the steam gets closer to the condenser, its remaining potential for electrical energy production decreases and much of its thermal energy will only be lost if it is allowed to reach the condenser. A second cogeneration principle is that it is more efficient to use steam turbines, driven by low value steam, to drive process equipment than to generate electricity and use motor drivers for the process equipment drives. NEEP employes both principles into its design.

Process energy in the form of steam and/or hot water is a product of the NEEP project to offsite consumers. Its quality will be determined by the extraction point within the combined-cycle facility, but will range from 70°F water to 465°F, 245 psig steam.

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Thermal energy in the form of steam and hot water will be extracted from the steam turbine of the combined-cycle power plant for direct heat applications. To allow for flexibility in thermal energy use, five thermal energy extraction points have been designed into the steam turbine generator system. Thermal energy from the extraction points, labeled A, B, C, D, and E on Figure 3-2, is characterized in Table 3-1.

It is the developers' intent to make thermal fluids available, both on and near the site, for commercial space and water heating, residential space and water heating, agricultural/aquaculture development and industrial processing.

As the project develops, it is likely to attract industries and business that can use the facility by-products of low pressure steam, separated gases (carbon dioxide, nitrogen, and argon) and hot water. A study has been completed that analyzed basic energy use and growth patterns of industries presently operating in the six state New England area on a county basis. Fifty-four industries were identified which met the following criteria:

- Annual energy use exceeds 10^{12} Btu.
- Does not require a large quantity of heat above 400°F.
- Relatively easy to relocate or is in a growth pattern.
- Employs more than 100 workers.

Certain industry groups tentatively appeared promising, both in terms of growth projections and energy requirements. These groups included paperboard, hardwood veneer, and plywood mills; paper coating and glazing; industrial organic chemicals; and synthetics and cotton finishing plants. In addition a large seafood processing industry is currently located in New Bedford about seven miles from NEEP.

Table 3-1

THERMAL ENERGY CHARACTERIZATION

Point	Extraction Point	Pressure (PSIG)	Temperature (°F)	Fluid Type
"A"	High Pressure Turbine	245	465	Steam
"B"	Low Pressure Turbine	50	298	Steam
"C"	Low Pressure Turbine	15	250	Steam
"D"	Condenser	20	70-100	Brackish Water
"E"	Low Pressure Turbine	85	325	Steam

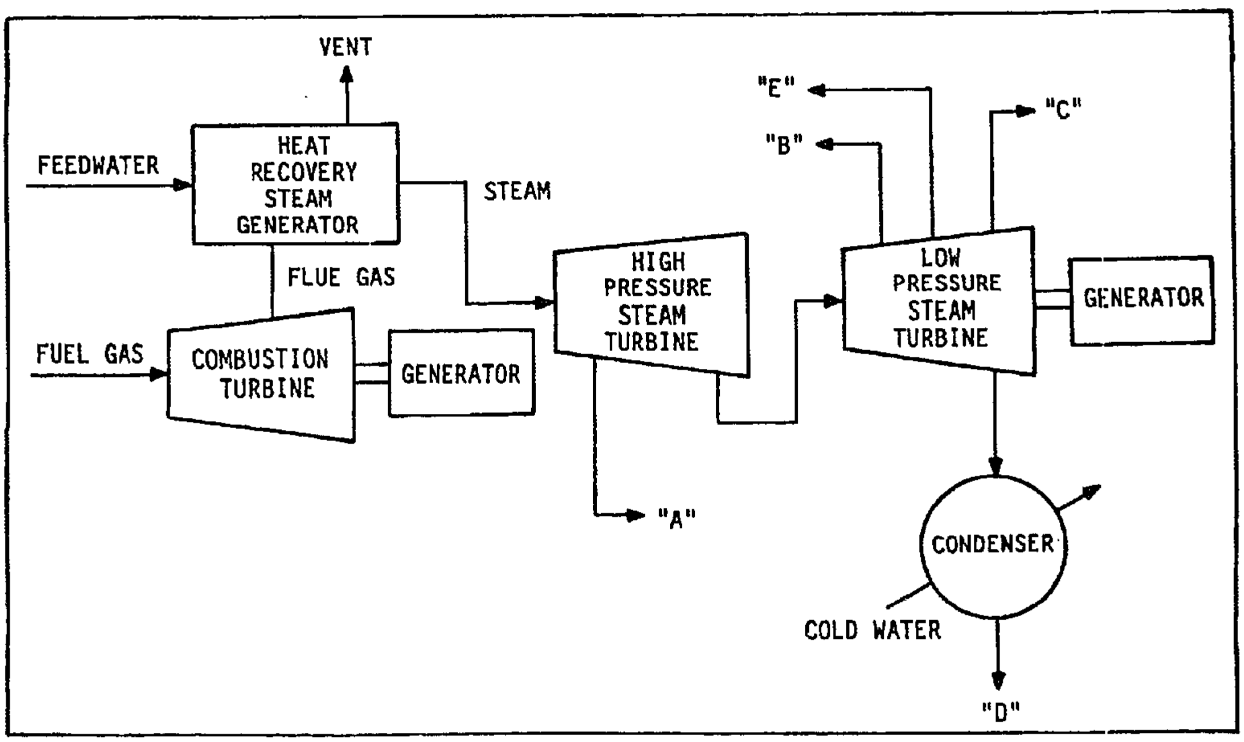

Figure 3-2

THERMAL ENERGY CHARACTERIZATION

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The industrial survey also indicated that the majority of the firms performed their operational development planning on a five year basis, thus dictating the marketing philosophy which should be integrated into the New England Energy Park business development plan. NEEP developers will continue to assess the potential markets, make initial marketing contacts and perform energy pricing evaluations. Approximately five years prior to startup of electric power generation equipment, the following business development activities will be performed:

- Define operational and business relationships for thermal energy users and industrial park participants;

- Complete industrial park development plans. These plans will include provisions for potable water, industrial water, waste handling, sewage, transportation, electric power distribution, and environmental management and control where applicable;

- Perform aggressive marketing for appropriate new and expansion facilities;

- Evaluate nearby industrial park developments for potential of retrofit development; and if economic delivery of thermal energy exists, perform marketing activities;

- Pursue the development of district thermal energy delivery systems for either residential or commercial facilities.

Considering the projected appliable industrial growth rate of 1.5×10^{13} Btu/year in the New England area, the existing industrial development in the New Bedford and Fall River areas near the site boundary, and the potential for residential, commercial, and agricultural space heating, a market capture rate of much less than 3% is needed to achieve the expected use rate of 60 x 10^6 BTU/hr.

3.2.6 Plant By-Products

Both sulfur and slag are by-products possessing commercial value that are produced in the plant process.

In the gasification process, most of the sulfur compounds that occur naturally in the coal are converted ultimately to elemental sulfur which can be sold to chemical companies to produce sulfuric acid and other products.

The sulfur recovery system employs Claus technology for conversion of the sulfur compounds to elemental sulfur, and a SCOT tailgas cleanup system.

Facility operations will also produce a maximum of 1,500 tons/day of slag, an inert, glassy, coarse-grained material that may find commercial value in building materials, sand-blasting material, insulation or other applications. The molten slag is quenched in the lower, water-filled section of the radiant boiler. The slag accumulates in the lock hoppers and is periodically discharged to the slag dewatering system. Dewatered slag is eventually transported by truck to a temporary onsite storage area.

3.3 RESOURCE REQUIREMENTS

3.3.1 Feedstock

The Texaco gasification process is relatively flexible on feedstock coals. Approximately 10,500 tons/day of coal will be required for gasification plant operation, the exact amount

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depending on the Btu content and other characteristics of the specific coal resource, as determined by a coal testing program. A coal supply study was conducted to identify potential coal supplies throughout the United States. A list of sources has been developed and is presented in Table 3-2. No decision has yet been made on the final coal suppliers.

The coals which are most likely to be used for the NEEP project will come from the eastern Appalachian area. Some of the coal may be washed at the mine mouth (to reduce ash content and increase the heating value) and some purchased "raw" or unwashed.

Coal characteristics upon which preliminary engineering design and estimates were made are shown in Table 3-3 and the most current design specification based on trade off studies is presented in Table 3-4.

3.3.2 Water Requirements

Present engineering estimates project a need for 12-18 million gallons of water/day (MGD), depending on the quality of the water. Based on the 12 MGD estimate, water usage is as follows:

	MGD
Processing Plant	8.3
Power Plant	3.0
Potable Clean Process Water	0.7

Estimates indicate that only 10,000 GPD must be of potable quality. According to the present process design, approximately 8 MGD of the 12 MGD demand should have a chloride content of less than 250 mg/l.

Table 3-2
POTENTIAL NEEP COAL SUPPLIERS

STATE	COAL COMPANY	MINE(s)	LOCATION (TOWN OR COUNTY)	SEAM	Million Tons of Reserve Coal Available: This Mining Property	Million Tons of Reserve Coal Available: Per Year To NEEP
West Virginia	Consolidated	Dents Run	Shinnston	Pittsburgh No. 8	123	2.5
	Pittston	Compass No. 3	Phillipi	"	60	1.0
	Eastern Coal Association	Federal No. 2	Grant Town	"	84	1.0
	Old Ben	Cumberland No. 1	Waynestown	"	98	2.0
	"	Robena	Carmichael	"	"	"
Kentucky	H.M.C. Coal	H.M.C. No. 1	Corbin	Blue Gem	10	N.A.
	Island Creek	Crescent	Central City	Kentucky No. 9	N.A.	2.0
	"	Hamilton	Morganfield	"	"	"
		Ohio No. 11	Uniontown	"	"	"
	Mapco	Dotiki	Clay	"		
	"	Retiki	Henderson	"	90	1.0
		Martiki	Lovely			
	R.L. Burns	Pyro	Sturgis		44	0.5
					>500 Million Tons	>10 Million Tons

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Table 3-3

STUDY BASIS COAL CHARACTERISTICS

Proximate Analysis

Constituent	Wet Basis (wt %)	Dry Basis (wt %)
Fixed carbon	43.3	47.6
Volatile matter	33.6	36.9
Ash	14.1	15.5
Moisture	9.0	-
	100.0	100.0

Ultimate Analysis

Constituent	Dry Basis (wt %)
Carbon	66.7
Ash	15.5
Oxygen	7.3
Hydrogen	4.5
Sulfur	4.5
Nitrogen	1.5
	100.0

Ash Fusion Temperature

Stage	Reducing Atmos. (°F)	Oxidizing Atmos. (°F)
Initial	1,990	2,400
Softening	2,070	2,450
Fluid	2,150	2,550

Coal Ash Analysis

Constituent	Wt %
SiO_2	49.7
Fe_2O_3	25.3
Al_2O_3	18.2
K_2O	2.5
SO_3	1.0
TiO_2	1.0
MgO	0.9
CaO	0.7
P_2O_5	0.2
Na_2O	0.2
Undetermined	0.3
	100.0

- Coal source: Western Kentucky Seam No. 9 (unwashed)
- HHV (wet basis): 10,900 Btu/lb
- HHV (dry basis): 12,000 Btu/lb
- Size received: 2 by 0 inch
- Free-swelling index: 2.5 to 6.0

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Table 3-4

NEEP COAL TENTATIVE SPECIFICATIONS

Most Probable

Location: Northern Appalachia (Northwestern West Virginia)

Proximate Analysis	Most Probable Value	Worst Case Value
Moisture	4%	6.0% Maximum
Ash	8%	11.5% Maximum
Volatile Matter	38%	*
Fixed Carbon	50%	*
	100%	100%
Ultimate Analysis		
Carbon	75.0%	68.0% Minimum
Hydrogen	5.0%	4.75% Minimum
Nitrogen	1.3%	1.4% Maximum
Sulfur	3.3%	4.5% Maximum
Chlorine	.05%	0.1% Maximum
Ash	8.0%	11.5% Maximum
Oxygen (By Difference)	7.35%	10.75% Maximum
	100%	100%
Heating Value	13,400 Btu	12,500 Btu Minimum
Ash Fusion (fluid reducing) Temp	2350°	2500°

*Texaco Process not sensitive to these criteria

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A water supply study was completed in February 1981. The study, conducted by the Resource Analysis Division of Camp, Dresser & McKee, demonstrated that there was sufficient water available within a 10-mile radius of the plant site to satisfy NEEP's water supply demands.

Demands for potable and process water (including a potential slurry line) were studied. The sources investigated include surface water streams, rivers, and impoundments; groundwater resources; water supply systems; wastewater treatment plants; and urban runoff. Water quality analyses have been conducted on the effluent from the Fall River Municipal Treatment plant to determine the types and quantities of impurities present. Significant process water resources considered by NEEP are presented in Table 3-5. Supply constraints are also noted.

Utilizing the data from the studies above and the expertise of the Wattuppa Water Board and City of Fall River Water Department personnel the following scheme of supplying water for the New England Energy Park has been developed.

The primary source of process water will be the Fall River Waste Water Treatment Plant. This plant has an average output in excess of 20 MGD although output can drop for short periods of time to the 8-9 MGD range. It is estimated that as much as 15 MGD may be required for process water using this source due to the quality.

The New England Energy Park will supply capital funds for a filtration plant to clean up water from the South Wattuppa Pond to a quality suitable for discharge into the North Watuppa Pond, which is the main Fall River water supply reservoir. In return the city will allow NEEP to use the Copicut Reservoir, which

Table 3-5

PROCESS WATER SUPPLY ALTERNATIVES

Source		Distance from NEEP Site (miles)	99% Safe Yield (MGD)	Water Rights Holder	Constraints to Use at NEEP
South Watuppa Pond		6	11.5-15.0	Fall River	Minimal
Lake Noquochoke		6	9.5-13.0	Fall River	Minimal
South Watuppa and Noquochoke Ponds		6	26.0-34.0	Fall River	Minimal
Three Mile River		10	34.0-44.0	Wading River Company	Acquiring rights; distance
Taunton River		10	---	Taunton	A standby source for City of Taunton.
Waste-water Treat-ment Plants	Fall River	10	21.1/28.0*	Fall River	All have pronounced quantity and quality variations.
	Taunton	10	6.1/8.1*	Taunton	
	New Bedford	10	39.1/39.5*	New Bedford	

*Present and future average design flows.

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adjoins the site and has a safe yield of about 6 MGD for a back-up source of process water. This assures a continuous supply of NEEP process water during periods of time when the Waste Water Treatment Plant is out of service for maintenance and during the infrequent low flow periods. The Copicut would also supply the 0.7 MGD of clean process water NEEP needs for filter and demineralizer back flushing, bearing cooling, etc. NEEP will also clean up Copicut water for its potable water requirements (10,000 GPD). In April 1982, NEEP entered into a Memorandum of Understanding with the Water Board of the City of Fall River formalizing the water supply arrangements.

3.3.3 Other Resources

Although large volumes are involved, the operating supplies required for NEEP should pose no availability problems in southeastern Massachusetts. The types and amounts of major consumable items are presented in Table 3-6.

Table 3-6
MAJOR CONSUMABLE ITEMS

Item	Use	Estimated Annual Use	
		Gallons (in 1000s)	Tons
Regeneration Chemicals	Demineralization		
- Sulfuric Acid		720	5,000
- Caustic Soda Solution		240	1,500
Lime	Wastewater Treatment	---	2,000
Make-up Solvent	Gas Cleanup Trains	240	900
Chemicals	Wastewater Treatment	240	1,000
Catalysts	Shift, Hydrolysis, and Methanol Synthesis	3	10

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Oxygen requirements for gasifier operation will be produced by NEEP's oxygen plant. Approximately 715,000 standard cubic feet of air/minute will be drawn from the atmosphere as feedstock.

No shortages of building materials required for plant construction are anticipated.

3.3.4 Labor.

The key factor which will determine the extent and direction of economic and social impacts on Fall River and surrounding communities, as a result of the New England Energy Park (NEEP) construction and operation, is the degree to which the existing economic base can provide goods and services during the construction phase of the project. The size, composition, and geographic distribution of the region's labor force, in relation to NEEP's required construction work force, will dictate the numbers of outside laborers who must migrate to the region for plant construction.

Careful planning during the design and construction phases of the project will help maximize the use of local labor and industries as the project proceeds. This is likely to be the most effective approach that can be taken to maximize local and regional economic benefits associated with NEEP.

The current high unemployment rate in the Taunton River Basin indicates that labor needs for this project will be satisfied to a considerable extent by members of the existing regional labor force.

Specific requirements for labor, including skills, numbers, and temporal distribution, will be developed as the design phase of the project progresses. Estimates of numbers and skills based

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on the results of projects constructed in the past or currently proposed are shown in Tables 3-7 and 3-8. Construction labor requirements are expected to reach a maximum of approximately 2800 during the ninth quarter of construction. The most significant skill requirements are pipefitters, carpenters, electricians, iron workers, and general laborers. Operational personnel will total about 467, and require generally higher technical levels of education, particularly for plant operators.

Table 3-7

ESTIMATED OPERATING PHASE LABOR REQUIREMENTS

Labor Classification	Number	Percentage of College Graduates
Supervisory	35	80
Plant Operators	214	20
Plant Maintenance	160	5
Laboratory	15	50
Safety	10	20
Administrative	10	50
Warehouse/Procurement	10	20
Miscellaneous	13	20
TOTAL:	467	--

The Southeastern Regional Planning and Economic Development District (SRPEDD) reports that the Fall River, New Bedford, and Taunton labor force totals over 190,000. The Fall River labor force is estimated at 77,000, 6,200 of whom are unemployed. For construction trades, SRPEDD reports a total work force of 26,500 for the three study areas. The compatibility of this labor force with NEEP construction requirements will be an important factor in determining overall project impacts in the areas of population, housing, transportation, and public ser-

Table 3-8

ESTIMATED CONSTRUCTION LABOR REQUIREMENTS

Crafts	Quarter 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16(1)
Boilermaker	--	--	5	29	52	105	170	186	188	158	133	99	79	58	27	5
Bricklayer	--	--	2	6	8	10	12	12	12	12	12	10	7	4	2	--
Carpenter	30	91	159	223	256	259	273	271	238	184	134	92	58	36	19	2
Cement Mason	4	11	17	29	37	41	46	58	52	32	26	17	13	22	12	--
Electrician	9	26	55	85	116	159	207	245	286	313	299	255	162	114	66	12
Iron Worker	8	26	49	76	114	152	170	188	173	163	124	88	57	49	27	7
Laborer	49	125	214	338	431	462	451	411	365	342	302	212	156	139	81	15
Millwright	--	2	6	8	15	26	55	55	39	38	33	20	12	10	8	2
Operating Engineer	24	37	60	81	100	121	134	148	144	136	123	91	73	57	27	7
Painter	1	4	7	9	7	2	---	3	7	11	25	53	35	25	18	10
Pipefitter	15	31	53	100	186	318	468	580	664	707	667	452	341	237	96	30
Insulator	--	--	--	---	---	---	1	8	12	17	35	48	50	40	25	20
Sheet Metal	--	--	6	10	13	21	26	30	30	34	29	23	13	10	10	8
Teamster	30	43	61	50	53	63	71	73	95	136	140	104	75	56	29	8
Surveyor	8	9	10	13	15	13	13	13	13	13	8	4	2	2	1	--
Total Manual	178	405	704	1,057	1,403	1,752	2,097	2,281	2,318	2,296	2,090	1,568	1,133	859	448	126
Total Non-Manual	32	80	132	207	275	345	405	444	465	433	360	266	172	106	56	15
Total Labor	210	485	836	1,264	1,678	2,097	2,502	2,725	2,783	2,729	2,450	1,834	1,305	965	504	141

NOTE

(1) Construction of the coal gasification and methanol plant is assumed to be completed in the 46th month after construction starts.

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vices. Experience in New England has shown that labor needs of large scale projects are largely satisfied by members of the existing regional labor force.

The construction manpower requirements have been discussed with the Southeast Massachusetts Building Trades Council. The Council has indicated that well over 90% of the required trades can be supplied from local labor or from labor pools within normal commuting distances from Fall River.

3.4 TRANSPORTATION

3.4.1 Resource Transportation

(a) Coal

An extensive coal supply and transportation study was conducted for the NEEP project. Transportation options examined in the study included:

- Rail movement from Appalachian and Kentucky coal fields to an east coast port;
- Water transport from east coast ports to a single Fall River site;
- A transshipment terminal at Fall River, with on-shore unloading capability and alternative coal storage schemes;
- Shipment from Fall River to the plant site.

Proposed coal delivery routes are shown in Figure 3-3. Table 3-9 lists the railroad-terminal combinations that have been carefully studied.

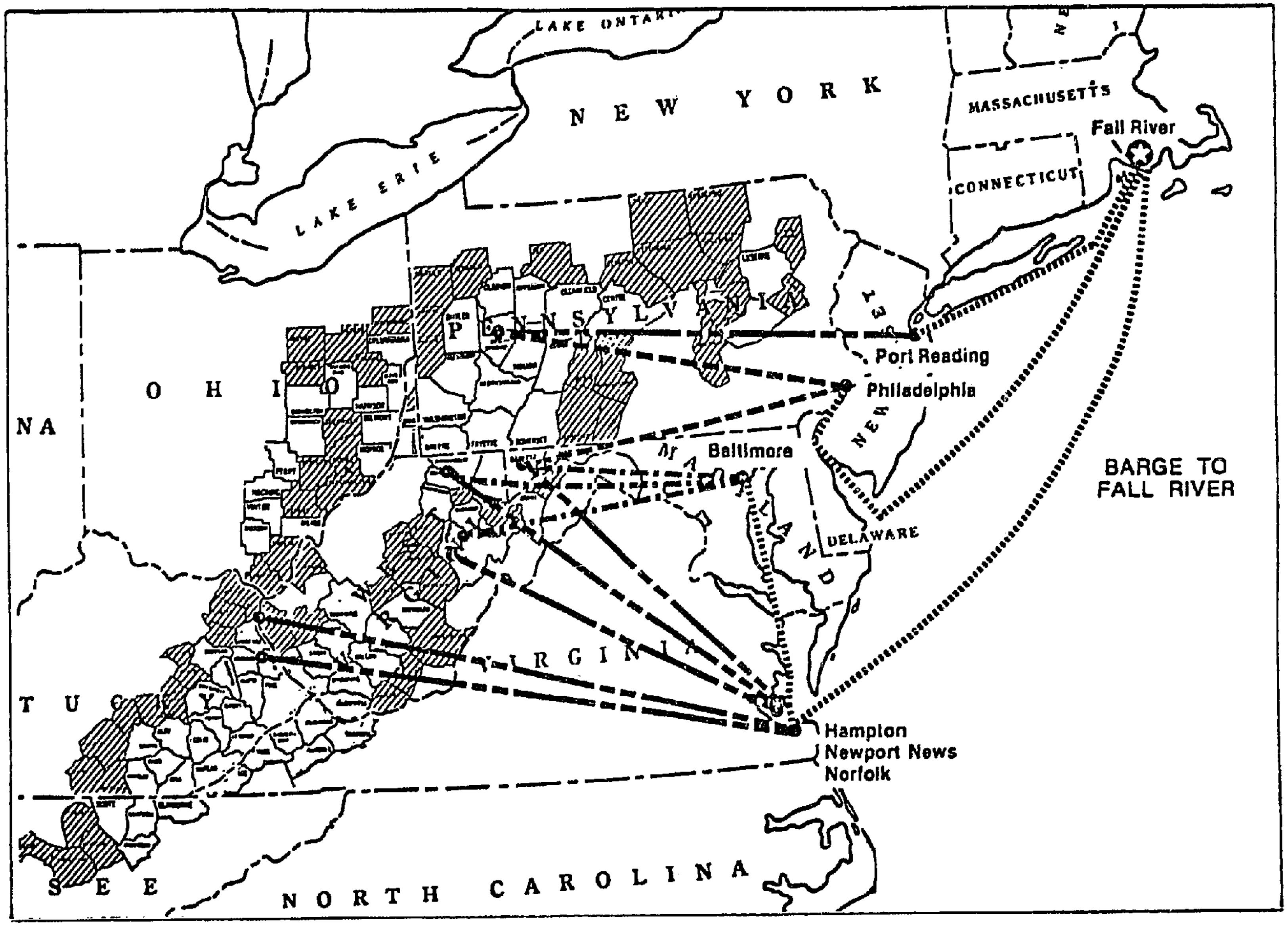

Figure 3-3

COAL RESERVES AND TRANSPORTATION ROUTES

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Table 3-9

RAILROAD/TERMINAL COMBINATIONS

Coal Producing Area	Railroad	Tidewater Terminal	Nautical Miles To NEEP Coal Terminal
Pennsylvania	Consolidated Rail (ConRail)	Port Reading, New Jersey	165
		Philadelphia, Pennsylvania	350
	Baltimore & Ohio (B&O)	Baltimore, Maryland	525
	Norfolk & Western (N&W)	Norfolk, Virginia	400
West Virginia	Southern Railway (SOU)	Norfolk, Virginia	400
		Charleston, South Carolina	775
West Virginia and Eastern Kentucky	Chesapeake & Ohio (C&O)	Newport News, Virginia	400
	Louisville & Nashville (L&N)	Newport News, Virginia	400
		Savannah, Georgia	850

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Letters from potential coal suppliers indicate their willingness to provide either minemouth or dockside Fall River delivery.

Coal delivery into Fall River is aided by the natural channel through Mount Hope Bay as far north as the Shell Oil Terminal on the Taunton River. The port has fifteen marine terminals, eight of which are used for receipt of petroleum products and two for receipt of industrial commodities such as latex, rubber and industrial acids. A state pier is used for transshipment of general cargo, another pier offers marine repair service, while the remainder of piers, wharves and docks are used for mooring. Ten of these facilities are located in Fall River, Massachusetts, three in Somerset, Massachusetts, and two in Tiverton, Rhode Island.

The port's traffic amounts to approximately 350 vessels per year and is comprised mostly of tankers and barges. Freighters also frequent the deep draught terminals. Fall River has recently completed a study of its State Pier area and may propose a $10 million modernization project designed to increase traffic by installation of roll-on/roll-off platforms, additional deep water docks, and coastal barge accommodations.

Coal will be unloaded at the NEEP coal terminal on the Taunton River. A site, south of the Braga Bridge adjacent to the rail line has been purchased for the terminal. The site has 2,000 feet of frontage on Mount Hope Bay and is bounded on the north by Ferry Street, on the south by Bay Street, on the east by Almond Street, and on the west by the Bay. The coal terminal facility will include a rail yard, a coal storage and reclaim facility, a concrete pier

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with two coal unloaders, a methanol loading station, and an administration building.

The terminal's coal handling system is designed to unload, receive, and handle coal from 30,000 DWT gearless vessels. Berth occupancy time will be approximately 50%, equivalent to 2.3 ships unloading per week, each ship carrying 30,000 short tons of coal.

The system consists of the following major facilities:

. Unloading and Transfer
. Storage and Reclaim
. Loadout

The unloading and transfer facility includes two grab bucket unloaders which travel on rails mounted on a 975-foot long by 85-foot wide concrete pier, one 2000-tph capacity city pier unloading conveyor. The facility is designed to unload coal from fixed-position vessels by means of traveling unloaders. The method of unloading coal from moving vessels by means of fixed-mounted unloaders was ruled out due to the awkward and time-consuming operation involved in maneuvering large 30,000 DWT vessels and due to limitations on the available bulkhead at the terminal.

The storage and reclaim facility includes one 2000 tph capacity tripper conveyor, one 60,000-ton storage barn, two 3000 tph capacity rotary plow feeders, and two 3000 tph capacity reclaim conveyors.

The storage barn is a 700 foot long by 80 foot wide, fully enclosed and covered structure. It conforms with the 100-foot height limit imposed on structures in the surrounding areas.

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The loadout facility includes two 3000-tph capacity loadout conveyors and a 400-ton loadout bin. The bin is a bifurcated type with discharge chutes designed for flood loading rail cars at a total rate of 600 tph. The bin provides the required surge between the loadout conveyors and the rail cars and simplifies loading control.

Coal is unloaded from 30,000 DWT vessels by means of two rail-mounted grab bucket unloaders which travel on a common 650-foot long runway and straddle the 54-inch belt pier unloading conveyor. Each unloader has a coal unloading capability at the free digging rate of 1000 tph. Continuous weighing of incoming coal is provided by a belt scale mounted on the pier unloading conveyor. At the discharge end of the pier unloading conveyor, as-received sampling of coal is provided for billing and/or inventory purposes. Additionally, the data obtained from as-received sampling may be used for establishing blending programs for the terminal storage facility. Coal is then discharged onto the 54-inch belt transfer conveyor which has the capability to convey coal directly to the rail cars via the 400-ton loadout bin or to discharge coal, by way of a fixed tripper, to the 54-inch belt tripper conveyor. Weighing of coal conveyed directly to the rail cars is accomplished by a belt scale mounted on the transfer conveyor section downstream of the fixed tripper.

When storing coal, the tripper conveyor distributes coal along the entire length of the 60,000-ton storage barn by means of a traveling tripper. The amount of coal conveyed to the storage barn is determined by the difference in readouts between the pier unloading conveyor belt scale and the transfer conveyor belt scale. The capacity of the storage barn represents two vessel loads and provides a

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buffer or surge between the terminal unloading facility and the active coal storage at the plant site.

A positive type of coal reclaim from the storage barn is accomplished by two rotary plow feeders which discharge coal to two 72-inch belt reclaim conveyors. Coal then discharges onto two 72-inch loadout conveyors which convey coal to the 400-ton loadout bin. Continuous weighing of coal reclaimed from the storage barn is provided by a belt scale mounted on each loadout conveyor.

Through the 400-ton loadout bin, coal is loaded on 20-car shuttle trains by flood loading loadout chutes at the rate of 6000 tph. This represents loading one 100-ton rail car per minute. While loading-in-motion, the train speed is maintained at approximately 2/3 mph with the use of pacesetter controls on the locomotives.

(b) Overland Transport

From the Fall River terminal, coal is transported overland to the plant site by a rail push-pull shuttle system.

The shuttle system includes a single train which consists of twenty 100-ton rapid discharge bottom-dump cars. Motive power is provided by two 2250-hp diesel locomotives. The average speed of the train along the entire route is estimated to be approximately 18 mph when fully loaded, and 24 mph when empty. The maximum train speed is 35 mph. At the plant site, coal unloading is accomplished using the concept of unloading-in-motion while the train speed is maintained at approximately 1/2 mph. When the train is unloaded, the locomotives push the empty cars back to the Fall River terminal.

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The average round trip cycle time is estimated as follows:

Shuttle Train Operation	Times (minutes)
Train loading	20
Loaded trip	40
Unloading	30
Empty trip	30
Positioning at terminals	20
Allowance for delays	20
TOTAL	160 or 2.67 hrs.

Depending upon the plant load factor (i.e. coal demand), the train would have to make up to six deliveries per day. For the plant operating at the design 90 percent load factor, the train will be operated 2 shifts a day, 6 days a week to meet the annual plant coal requirement of 3.5 million tons.

The shuttle train fleet includes 3 standby cars (15 percent spare) in addition to the 20 operating cars to allow adequate preventive maintenance.

(c) Water

Potable and process water supply sources were discussed in Section 3.3.2. Water will be piped to the site in buried mains.

(d) Construction Equipment and Labor

The movement of construction materials and personnel onto the site does not appear to present any major hurdles. The Fall River area is served by rail lines operated by Consolidated Rail Corporation (Conrail). In addition, the site is surrounded on all sides by State and Federal limited access highways, one of which is connected to the transpor-

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tation corridor as is Conrail's Newport Line. Conrail indicated it may abandon the Newport Line; however, EG&G, is negotiating an agreement with Conrail to purchase the Massachusetts portion of the line providing the State does not exercise its right of first refusal. Should the State procure the line, EG&G has been assured that whatever easements are required for NEEP will be provided by the State.

3.4.2 Products Transportation

In addition to the Conrail and site branch line rail systems, which will also serve as product outbound lines, a major electric transmission line and natural gas pipeline cross the site east and west and north and south respectively (see Figure 3-9). Both powerlines and pipelines are prevalent in Fall River, due to the close proximity of two major electrical power plants (Brayton Point and Montaup), a synthetic natural gas plant, and an oil products terminal on the Taunton River. The power line network will provide ready access for the proposed power facility's electricity output. A methanol line will be installed to the coal terminal for transfer to ships.

3.4.3 Transportation Corridor

In order to transport materials from the NEEP coal terminal on the Taunton River to the NEEP site located in the northeast side of the city, a transportation corridor was needed for the following functions:

- Movement of 3.5 million tons annually of coal from the coal terminal to the project site.

- Movement of 15-18 MGD of process water from the City's wastewater treatment plant (also located on the Taunton River on the southwest side of the City) to the plant site.

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. Vehicular access for employees during construction and subsequent operation.

. Movement of other materials/supplies into the project area, as well as the shipment of products from the Energy Park.

. Utility lines (gas, methanol, wastewater, etc.).

The movement of materials to and from the site was examined during the feasibility study, primarily focusing on coal transport. After considering the possibility of slurry line and covered conveyor, a decision was made to develop a rail connection to the Park because both slurry and conveyor modes are limited to the movement of a single commodity (coal), uni-directional to the Park. The selection procedure used to locate the best route for rail spur and a vehicular access road into the plant property is summarized in the report entitled "Evaluation of Alternate Routes for a Transportation and Access Corridor to the New England Energy Park," March, 1982. The selection criteria focused on minimizing the corridor's impact on residences and the environment. The report concluded that the corridor should follow the existing Conrail line (Newport Secondary Line) which passes through the coal terminal and runs northerly. At a point approximately seven miles from the coal terminal, adjacent to the intersection of the rail line and Route 24, a new rail spur will be built which will run southeasterly for a distance of about four miles into the Energy Park. The separate vehicular access route would extend from Riggenbach Road (adjacent to the Fall River Industrial Park) and merge with the rail corridor.

This proposed transportation corridor passes under Route 24 and through the Freetown-Fall River State Forest. A two-thirds vote of the state legislature is required to obtain a right-

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of-way through this Forest area. On December 4, 1981, Massachusetts House Bill 5792 was filed requesting easements for a transportation and access corridor to the New England Energy Park. The bill provides for consideration for said easement "which shall be acceptable to the grantor and which shall be determined to be at least equal in market value to the easements granted". The easement involves approximately 160 acres of the total 5,400 acres of the forest.

Extensive meetings reviewing the legislation were conducted with relevant state and city agencies, including the Department of Environmental Management; the Department of Environmental Quality Engineering; the Department of Fisheries, Wildlife and Recreational Vehicles; the Massachusetts Environmental Policy Act unit; the Department of Public Works; the City of Fall River Water and Conservation Boards; and the Freetown Conservation Commission. On March 25, 1982, the Joint Committee on Transportation (the committee empowered to act on the legislation) conducted a public hearing in Fall River, Massachusetts. Subsequently, the bill was favorably reported out of Committee and received initial approval by the House and was sent to the Senate on May 18, 1982. Passage of this legislation by the Massachusetts legislature is expected this summer.

As mentioned earlier, the first part of the route of the NEEP shuttle rail line from the coal terminal into the Energy Park is the existing Newport Secondary Line which starts in Berkley, Massachusetts, and extends through Freetown and Fall River, to the Rhode Island state line. The line passes beside the NEEP coal terminal in the south end of Fall River, and also through the City's waste treatment facility located on the Taunton River. The project will obtain its necessary process water by tapping the sewer effluent at the City's secondary treatment plant and routing it in a 30" pipe, along the railroad right-

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of-way and through the transportation corridor. Another use for the Newport Secondary Line right-of-way is for a pipeline to move methanol from the plant site, along the rail line to the coal terminal, for barge shipment out of the Fall River area.

Thus, it was critical that the project obtain the necessary rights to use the Newport Secondary Line. Accordingly, an offer to purchase the line was tendered to the Conrail. Under the offer the NEEP would own the rail property and Conrail would retain operating rights on the line. Negotiations were completed in April, a value on a per-acre basis was established, and the purchase and sale agreement has been approved and should be signed shortly.

3.5 WASTES AND DISCHARGES

Protection of air and water quality and safe disposal of solid residuals are key environmental issues associated with NEEP. The major waste streams of NEEP and their general nature and potential environmental impacts have been identified. Specific components will be a function of both the final engineering design and the coal used for gasification. As large scale coal gasification is relatively new in the U.S., the EPA is still characterizing waste stream components for regulatory purposes.

Overall emissions and waste treatment requirements are reduced in the Texaco process. Because of the high operating temperature of the Texaco gasifier, by-product tars, phenols, and other hydrocarbons heavier than methane are minimized. High-temperature operation also permits recovery of the coal ash as a granular slag rather than as fly ash, thus minimizing ash disposal problems. Fuel gas cleaning, wastewater treatment, and solid waste disposal are therefore much simplified compared to other gasification processes. Most of the process water is recovered and recycled to the gasification system, with only a small purge stream needing treatment prior to disposal.

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Plant emissions are divided into four major categories: fugitive particulate emissions, gaseous emissions, liquid wastes, and solid wastes. The plant emissions are discussed in Section 8.6.

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4. PROCESS DESCRIPTION

4.1 INTRODUCTION

The New England Energy Park (NEEP) is a grass-roots coal-based energy complex, which will produce electricity, methanol, and synthetic natural gas (SNG), utilizing the Texaco coal-gasification process. This report describes the various activities that have been performed to date.

The entire project has been studied in sufficient detail to permit strategy planning, identification of critical areas, and evaluation of various courses of action leading to successful project execution. The gasification technology selected is the oxygen-blown Texaco Coal Gasification Process (TCGP). The product plants within the facility are designed to produce 645 MW (gross) of electric power, 2500 tpd of methanol, and 50 MM SCFD of SNG. NEEP is designed with a 1/3 excess process plant capacity shared among the three product plants. The various processes are integrated to maximize energy efficiency. Environmental controls are incorporated to minimize environmental impacts. The system was designed for a feedstock of 10,500 tpd of a high sulfur, caking-type, eastern bituminous coal. Design is expected to achieve a 90 percent operating capacity factor.

The overall block-flow diagram for the NEEP facility is shown in Figure 4-1.

4.2 TECHNOLOGY ASSESSMENT

Coal gasification is essentially a century old process that produces carbon monoxide and hydrogen (i.e., coal gas) from coal. Existing commercially proven coal gasification process, such as Lurgi, Koppers-Totzek, Winkler, Wellman, etc. have been used for decades to produce synthesis gas in Europe and countries where liquid fossil

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fuel resources are limited. The need for a competitive cost advantage over hydrocarbon-based energy and the compliance with stringent environmental regulations have posed challenges to existing first generation gasification processes. The demand for better technology has resulted in the recent development of efficient, economical, and environmentally acceptable high-pressure, high-temperature, second-generation coal-gasification processes, such as BGC-LURGI, Texaco, and others. The TCGP, in general, has many advantages over the existing first-generation and other second-generation processes. These advantages are associated with operating experience and scale-up risk.

4.2.1 Operating Experience

In selecting processes for any large energy project, technical concerns are frequently addressed by comparing the design to other plants that use the processes under similar operating conditions. NEEP uses commercially proven technologies for all processes, with the exception of the TCGP. The TCGP, however, is not a new technology. It is a natural extension of the Texaco partial oxidation process. The Texaco partial oxidation process has been used to convert many types of organic materials from one form to another. The process has been used successfully on a commercial scale for 30 years with materials ranging from gases to heavy oil residuum. More than 75 plants using this process have been built in 22 countries. The TCGP has been designed to build upon this experience with fluids by first converting the solid coal to fluid form (i.e., a coal slurry). The process has not yet been demonstrated on a commercial scale with coal. Nevertheless, the Texaco Coal Gasification Process embodies many of the commerically proven features of the oil partial oxidation process.

Texaco is currently operating a 15-tpd pilot facility at Montebello, California. Two gasifier trains are used to test dif-

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ferent coals at pressures ranging from 300 to 1,200 psig. The pilot units are used for process development and for establishing design criteria for a specific coal.

A 165-tpd Texaco gasification unit has been operated by Ruhrkohle and Ruhrchemie in Oberhausen-Holten, West Germany, since 1978. This perhaps is the most significant advantage of the Texaco coal-gasification process. As a consequence of the process development conducted for a number of years, the gasification train has now been placed in successful operation. The waste heat recovery train (radiant boiler, convective boiler, and economizers) has been operating for almost a year without mechanical problems. Although this unit is rated at 165 tpd, it nevertheless has gasified higher throughputs of different types of coal and various slurry concentrations.

In addition to the West Germany unit, a 200-tpd Texaco coal gasification unit is currently in operation at TVA's ammonia-from-coal plant at Muscle Shoals, Alabama. This unit uses direct quench instead of waste-heat boilers for raw gas cooling.

Two major Texaco coal gasification products are scheduled for start-up in 1984 and 1985. One project will produce chemicals from coal for Tennessee Eastman Company. The other project, the Cool Water Coal Gasification Project, will produce medium Btu fuel gas for a 100-MW combined-cycle power plant. Both projects employ gasifiers of similar size to NEEP.

4.2.2 Scale-up Risks and Mitigating Measures

As mentioned earlier, the processes used in this design utilize commercially proven technologies, with the exception of the Texaco process on coal. However, the risks for scale-up for all major process plants were investigated.

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4.3 DESIGN BASIS

4.3.1 Assumptions and Guidelines

The following major assumptions and guidelines were established as a basis for the conceptual design:

- Feedstock will be 10,500 tons per day of high-sulfur, unwashed, Eastern U.S. bituminous coal as represented by Kentucky No. 9.
- Coal will be shipped by water to the coal terminal on the Taunton River in Fall River, Massachusetts, and transported to the site by rail.
- Texaco Coal Gasification Process will be used.
- No direct coal firing will be allowed, all coal will be gasified to minimize SO_2 emissions.
- The plant will be capable of producing 3 products simultaneously with maximum raw gas consumptions of 2/3 to power, 1/3 to methanol, and 1/3 to SNG.
- Methanol maximum production will be 2,500 tons per day.
- SNG maximum production will be 50 million SFCD.
- The power plant will consume all fuel gas produced and will have a net electric power output of approximately 550 MW.
- The plant full operational capacity factor goal will be 90 percent.

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- Electric power will be produced in a combined-cycle power plant fired with medium-Btu gas. The medium-Btu gas has a nominal Higher Heating Value (HHV) of 285 Btu per standard cubic foot and a maximum sulfur content of 200 ppmv, and is delivered at a minimum pressure of 200 psig.

- A major by-product of the plant is elemental sulfur. Molten sulfur is recovered at a maximum rate of 425 short tpd.

4.3.2 Sources of Data

(a) Gasification Process Data

A standard "Type B" design package was obtained from the Texaco Development Corporation for the conceptual gasification plant design. This package included:

- Estimate of operation containing:
  - coal feed rate
  - oxygen feed rate
  - water feed rate
  - quantity of gas produced
  - composition of gas produced
  - output of rejected slag

- Utilities required for some battery limits, calculated for this specific case, including:
  - steam consumed
  - steam produced
  - boiler feedwater required
  - cooling water required
  - electric power required

- List of major pieces of equipment

- Simplified process flow diagram

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(b) Licensor Information

Gasification and Waste Heat Recovery

Equipment sizes and the budget capital cost estimate were obtained from Combustion Engineering for a similar project. This estimate included the number of trains, equipment summaries, design parameters, metallurgies, and plot space.

Air Separation

A budget estimate was obtained from Air Products and Chemicals, Inc., for the 8,500 ton/day oxygen plant. This estimate included the utility requirements, number of trains required, preliminary installed cost estimate, plot area required, and a description of the major equipment items.

Acid Gas Removal

The Selexol acid gas removal system were designed by Bechtel with the aid of a computer program supplied by the Selexol Department of Allied Chemical Corporation. The program performs overall heat and material balances, and sizes some of the major equipment. The installed cost of the equipment was estimated by Bechtel.

Sulfur Recovery

A budget quote was obtained from Black, Sivalls, & Bryson for the Claus sulfur recovery and SCOT tail gas treating plant. This included preliminary installed costs, utility requirements, and catalyst and chemical requirements.

Shift Conversion

Catalyst performance and cost information was obtained from Haldor-Topsoe for the shift and COS hydrolysis reactors.

Methanol Synthesis

Information on the design and cost of the methanol synthesis unit was obtained from the Lurgi Corporation. This included the overall material and energy balance, utility requirements, preliminary installed-cost estimate, and catalyst requirements.

SNG

The methanation unit design was based on Cono-Meth technology licensed by Conoco. This included licenser information on the overall process. This information was used to design all process equipment and to carry out overall heat and mass balance. The installed cost of the unit was estimated by Bechtel.

Electric Power Generation

The electric power unit for NEEP is based upon the Stony Brook Energy Center of the Massachusetts Municipal Wholesale Electric Corporation (MMWEC) which is very similar to the conceptual design for NEEP. The plant began commercial operation in 1981. Performance information unique for NEEP was obtained from General Electric and compared with information from Westinghouse and Brown-Boveri.

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For all of the above, licensor information received was verified by Bechtel and compared to previous data. In some cases, plant designs were modified by Bechtel to increase the overall thermal efficiency or to be consistent with the overall plant utility system.

4.3.3 Environmental Guidelines

The process and power plant facilities for the New England Energy Park have been designed to meet or exceed all existing federal, state, and local environmental standards. Sulfur dioxide emissions from the combined-cycle power plant have been set at about one-sixth of the level allowed from a coal-fired boiler with scrubbers. New Source Performance Standards for overall coal gasification facilities have not yet been issued. However, emission regulations have been promulgated by EPA for certain individual units (auxiliary boilers, Claus sulfur plants, and petrochemical plants). These regulations have been reviewed and used as appropriate. The control technology employed is that typically used in the petroleum refining and steam-electric power generation industries. All input coal is gasified to minimize sulfur dioxide emissions and solid waste disposal. Internal plant fuel demands are satisfied by firing clean medium-Btu gas or purge gas stream. The site arrangement allows all gasifier slag to be stored on site. There are no spent catalysts requiring landfill.

The amount of fresh water used is reduced by recycling internal process water flows to the maximum extent allowed by the individual process units. All process effluent streams are treated and monitored before discharge. Section 8 contains the discussion of the detailed guide lines.

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4.4 PLANT DESIGN

4.4.1 Process Selection.

The overall block flow diagram for producing methanol, SNG, and electric power using the Texaco coal gasification process was shown in Figure 4-1. The overall material balance is shown on Table 4-1. Some of the major process decisions that influenced the arrangement of the process units are as follows:

. All coal is gasified to minimize sulfur emissions and solid waste disposal. The power plant is fired with medium-Btu fuel gas.

. Raw gas flow is split. The fuel gas, methanol, and SNG gas streams are then treated separately, according to the required levels of sulfur removal, CO/H_2 shift required, and CO_2 removal.

  Product slate flexibility is provided such that combinations and permutations of product slates can be produced simultaneously to respond to market demands.

. Waste process heat is utilized to the maximum practical extent to generate steam for mechanical drive turbines and process heating. Where required, steam from high-pressure waste-heat boilers is further superheated.

. Fresh water use is reduced by recycling internal process water flows to the maximum extent allowed by the individual process units.

. Methanol synthesis uses low-pressure technology requiring no external source of energy for either feed, recycle compres-

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- Methanation unit uses Cono-Meth process technology to produce SNG.

Detailed descriptions of the processing units are presented in the subsequent sections.

4.4.2 Detailed Facility Descriptions

(a) Site Coal Handling

The site coal handling system is designed to receive, handle, and process coal at the NEEP plant site, and to ensure a continuous supply of coal to the eight Texaco entrained-flow, oxygen-blown, slagging gasifiers. To meet the high availability requirement for the system, the system design has incorporated the use of emergency reclaim and equipment redundancy in critical areas. The system consists of the following major facilities:

- Track Hopper Unloading
- Active Storage and Reclaim
- Emergency Reclaim
- Coal Crushing and Sampling
- Silo Feed Distribution and Rod Mill Feeding

The track hopper unloading facility includes one 1000-ton capacity track hopper, two 3000 tph capacity rotary plow feeders (one operating, one standby), one 3000 tph capacity collecting conveyor, and one 3000-tph capacity unloading conveyor. The top hopper opening length is 155 feet.

The active storage and reclaim facility includes one 3000-tph capacity radial stacker conveyor, one 30,000-ton capacity active storage pile, two 875-tph capacity rotary plow

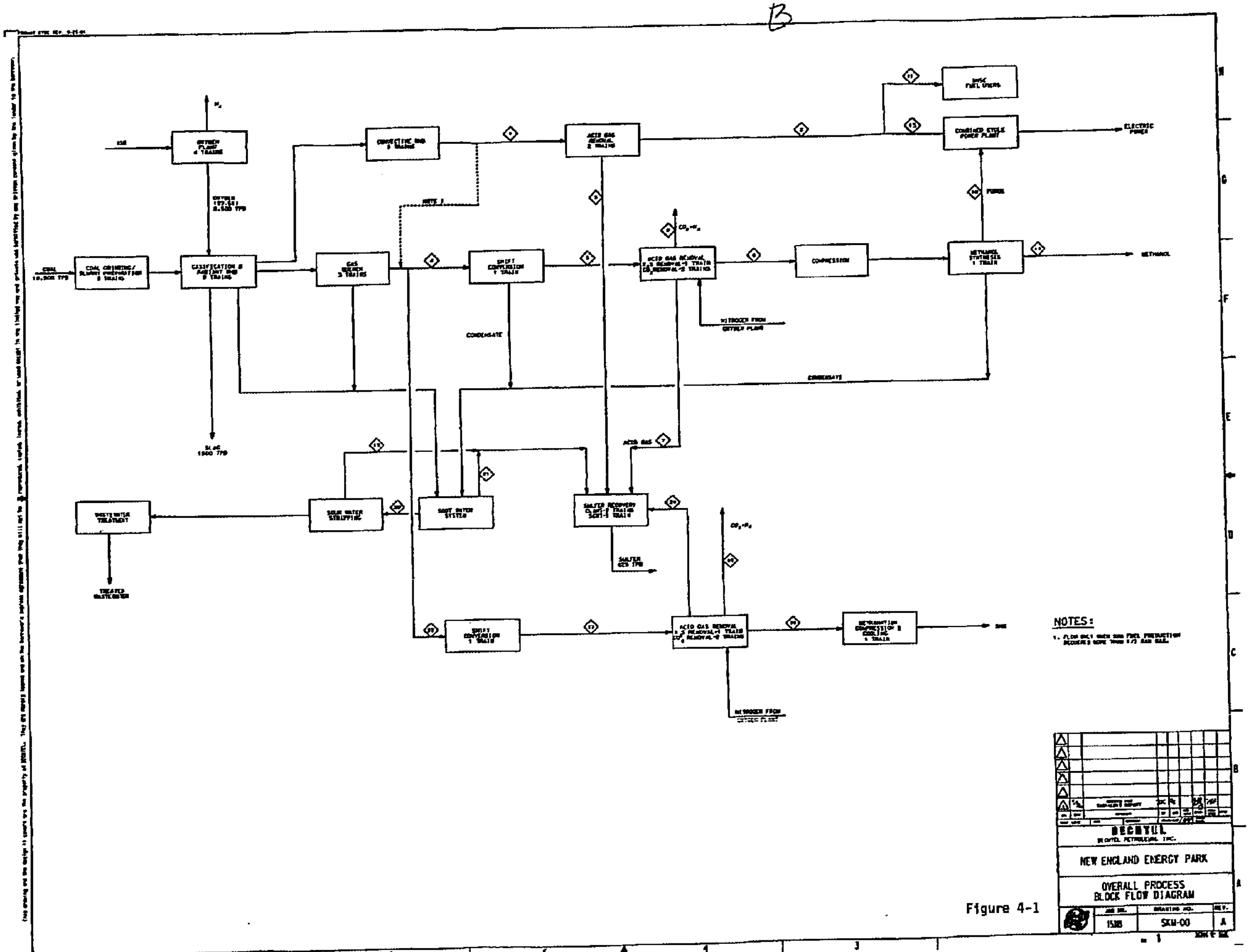
COAL CRUSHING/ SLURRY PREPARATION 8 TRAINS
GASIFICATION & AMBIENT GAS 8 TRAINS
OXYGEN PLANT 4 TRAINS
CONVECTIVE GAS 8 TRAINS
ACID GAS REMOVAL 2 TRAINS
GAS QUENCH 3 TRAINS
SHIFT CONVERSION 1 TRAIN
COMPRESSION
METHANOL SYNTHESIS 1 TRAIN
COMBINED CYCLE POWER PLANT
ELECTRIC POWER
METHANOL
CONDENSATE
SOUR WATER STRIPPING
SOOT WATER SYSTEM
SULFUR RECOVERY
WASTEWATER TREATMENT
TREATED WASTEWATER
NOTE 1
NOTES:
BECHTEL
NEW ENGLAND ENERGY PARK
OVERALL PROCESS BLOCK FLOW DIAGRAM
SKM-00

Figure 4-1

Table 4-1
OVERALL MATERIAL BALANCE

STREAM	1	2	3	4	5	6	7	8	10	11	13
COMPONENT	COOLED RAW GAS	CLEAN MEDIUM BTU GAS	ACID GAS (FUEL GAS)	QUENCHED RAW GAS	SHIFT EFFLUENT	METHANOL SYNTHESIS FEED	ACID GAS (METHANOL TRAIN)	CO_2 VENT	METHANOL PURGE GAS	MEDIUM BTU GAS TO USERS	MEDIUM-GAS TO POWER
CO	20,497	20,480	16	11,884	6,080	6,050	1	29	68	485	19,995
CO_2	7,251	5,071	2,224	4,204	10,032	690	842	8,500	87	190	4,881
H_2	15,163	15,163	2	8,791	14,595	14,581	1	13	808	1,117	14,043
CH_4	131	131	-	76	76	75	-	1	75	78	53
H_2O	107	31	127	31,165	54	-	54	-	2	3	28
N_2 + Ar	339	339	-	197	197	197	-	3,136	197	204	135
H_2S	666	2	664	386	410	-	410	0.015	-	0.04	1.96
COS	42	2	40	24	-	-	-	0.18	-	0.04	1.96
CH_3OH	-	-	-	-	-	-	-	-	75	-	-
NH_3	-	-	-	-	-	-	-	-	-	-	-
Total lb-mol/hr	44,196	41,174	3,073	56,727	31,444	21,593	1,308	11,679	1,312	2,152	39,022
Total 1,000 lb/hr	962.6	837.9	125.6	1,118.9	663.4	236.4	52.0	470.4	17.0	34.1	803.8
HHV, Btu/scf	274	285	-	124	223	312	-	-	325	289	285

Table 4-1

OVERALL MATERIAL BALANCE (CONT.)

STREAM	14	19	20	21	22	23	24	25	26
COMPONENT	METHANOL PRODUCT	ACID FROM SOUR WATER STRIPPING	B.D. FROM SOOT WATER SYSTEM	ACID GAS MEDIUM (FUEL GAS)	QUENCHED GAS	SHIFT EFFLUENT	ACID GAS FEED	CO_2 VENT	CLEAN GAS TO METHA-NATION
CO	-	-	-	3.64	11,884	4,088	2.0	8	4,878
CO_2	-	5.4	5.4	67.88	4,204	11,163	1,352	9,164	647
H_2	-	-	-	15.97	8,791	15,666	1	5	15,760
CH_4	-	-	-	0.01	76	76	-	1	75
H_2O	17	2.1	13,626	5.02	23,773	58	76	25	1
N_2 + Ar	-	-	-	0.09	197	197	-	4,000	197
H_2S	-	0.8	1.4	7.65	386	401	401	0.015	-
COS	-	-	-	0.39	24	0.3	0.12	0.18	-
CH_3OH	6,510	-	-	-	-	-	-	-	-
NH_3	-	-	7.9	-	-	-	-	-	-
Total lb-mol/hr	6,527	9.5	13,640	97.50	49,335	32,549	1,832	13,203	21,558
Total 1,000 lb/hr	208.9	0.32	-	3,497.4	985.62	681.49	74.50	516.09	203.68
HHV, Btu/scf	-	-	-	-	-	-	-	-	-

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feeders (one operating, one standby), one 875-tph capacity reclaim conveyor, and one 875 tph capacity crusher feed conveyor. Active storage is a "kidney-shaped" open pile formed by coal discharged from the 100-foot-long radial stacker conveyor. Directly below the pile is the 240-foot-long reclaim tunnel.

The emergency reclaim facility includes one 150-ton emergency reclaim hopper and one 875 tph capacity emergency reclaim conveyor. The emergency reclaim hopper is an underground bin of welded and bolted steel construction and of bifurcated design having two bottom hoppers. Each bottom hopper outlet is equipped with an 875-tph capacity vibratory feeder. Both feeders, one serving as backup to the other, discharge coal into the emergency reclaim conveyor.

The coal crushing and sampling facility includes one 150-ton capacity crusher surge bin, two 875-ton capacity coal crushers (one operating, one standby), two 875-tph capacity crusher discharge conveyors (one operating, one standby) and one complete as-fired sampling system. The crushed coal is conveyed to the coal slurry preparation system.

A suitably prepared area is provided for inactive (or long-term) storage of approximately 600,000 tons of coal which is equivalent to a 60-day coal requirement of the plant at maximum capacity loading.

The storage pile area is approximately 16 acres based on an average pile height of 25 feet, 75 to 85 lb/ft^3 compaction density and 2.5:1 pile side slopes.

Stockpiling is accomplished by use of plant mobil equipment prior to commercial operation. When the pile is complet-

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ed, present plans are that it will be covered with soil and seeded with grass to minimize the possibility of spontaneous combustion and loss of coal due to wind erosion.

The site coal handling system encompasses the operations as illustrated by the flow diagram shown on Figure 4-2.

Coal transported by rail from the Fall River terminal is received by the 1000-ton track hopper at the track hopper unloading building. The track hopper is sized to provide for coal surge due to the difference between unloading rate and reclaim rate within the time it takes to unload the 20-car train, and to compensate for volume loss due to uneven withdrawal of coal, hangups or material buildup, etc., in the hopper.

A positive type of coal reclaim at 3000 tph from the track hopper is accomplished by one operating rotary plow feeder which travels inside an A-frame tunnel. The tunnel straddles a long horizontal slot which forms the bottom discharge opening of the track hopper. Coal then drops into the 72-inch belt collecting conveyor beneath the horizontal slot.

From the collecting conveyor, coal discharges onto the 72-inch unloading conveyor where an integral belt scale provides continuous weighing of coal reclaimed from the track hopper. The coal discharges from the unloading conveyor to the 72-inch belt stacker conveyor for active storage.

When conveying coal for active storage, the radial stacker conveyor distributes the coal onto the active storage pile by means of a telescoping chute. The active storage capacity represents a 3-day coal requirement of the plant at maximum capacity.

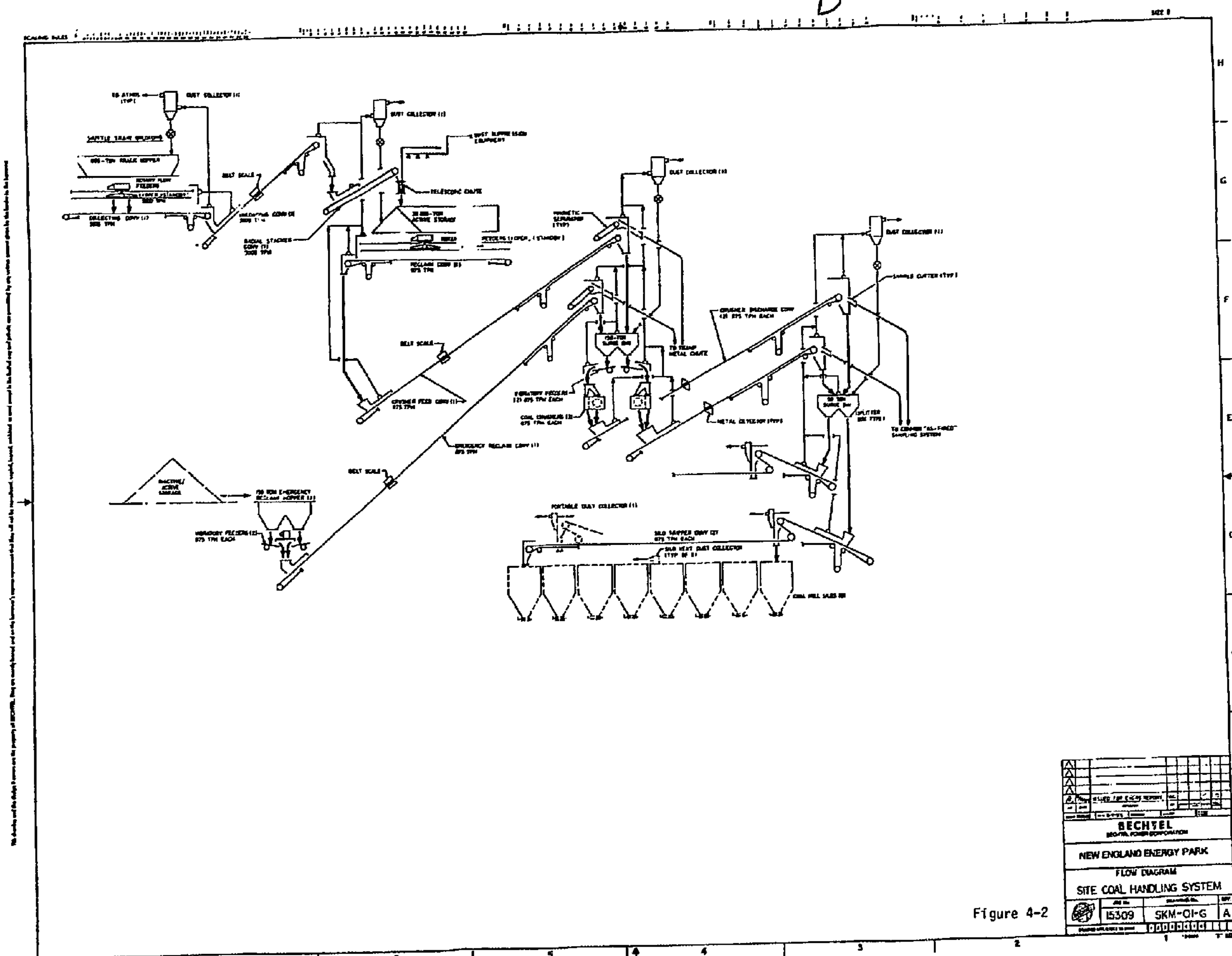
BECHTEL
NEW ENGLAND ENERGY PARK
FLOW DIAGRAM
SITE COAL HANDLING SYSTEM
15309
SKM-01-G
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Figure 4-2

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During normal operation, a rotary plow feeder traveling inside a horizontal tunnel reclaims coal from beneath the active storage pile for discharge to the 36-inch belt reclaim conveyor. The reclaim rate is 875-tph which is 200 percent of the total maximum gasifiers burn rate. The reclaim conveyor transports coal to the crusher feed conveyor, which in turn, feeds coal to the crusher surge bin. Continuous weighing of coal reclaimed from active storage is provided by the belt scale mounted on the 36-inch belt crusher feed conveyor.

During an emergency situation, or when the active reclaim equipment fails, coal from the active or inactive storage pile would be moved by plant mobil equipment to the emergency reclaim hopper. Coal then is fed to the 36-inch belt emergency reclaim conveyor, which in turn, conveys coal to the crusher surge bin. Continuous weighing of coal reclaimed from the active or inactive storage pile will be provided by the belt scale mounted on the emergency reclaim conveyor.

Tramp metal is removed from the coal stream by a magnetic separator located at the head end of each conveyor feeding the crusher surge bin. Downstream of the crusher surge bin, which has two discharge outlets, are two identical equipment trains, one being redundant to the other. Each train consists of equipment starting from the crusher surge bin outlets up to, and including, the tripper conveyors feeding the rod mill silos.

The operation of each equipment train is such that coal from the crusher surge bin is fed by one vibratory feeder to a crusher which reduces coal to 3/4-inch nominal top size. The crushed coal drops into one 36-inch belt crusher

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discharge conveyor which then conveys coal to the sampling building. The discharge chute of each crusher discharge conveyor is fitted with a primary sample cutter which feeds sample coal to a common sampling system which provides the performance testing of as-fired coal. Additionally, the data obtained from as-fired sampling may be used to determine the degree of blending achieved at the terminal storage facility.

From the sampling building, coal is conveyed by one silo tripper conveyor to the rod mill building where coal is distributed by means of a traveling tripper to eight rod mill silos. The bottom discharge spout of each silo is fitted with a gravimetric-type belt feeder which feeds coal to a rod mill. Each silo is supported on load cells which are used to control the supply of coal by the traveling tripper to the silo.

In both the terminal and site coal handling systems, all conveyor sections outside building enclosures (except the loading section of the pier unloading conveyor) are completely enclosed including conveyor galleries. Conveyor transfer structures are complete with roofing and insulated sidings. Creep drives are provided on outdoor conveyors to prevent cold weather setup of belting and lubricant. Dust collection systems are provided throughout with dust pickup points in all coal transfer areas. Wet dust suppression is also provided at the 400-ton loadout bin and at the discharge chute of the radial stacker conveyor.

Fire detection and fire protection systems are provided in all coal conveyor galleries as well as in coal transfer and storage structures.

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(b) Coal Slurry Preparation

The coal slurry preparation system is schematically represented on process flow diagram, Figure 4-3.

The silo feed distribution and rod mill feeding facility includes two 875-tph capacity silo tripper conveyors, eight 750-ton capacity coal mill silos, and eight 62 tph capacity gravimetric belt feeders.

The storage capability of each silo is equivalent to a 12-hour coal requirement of one gasifier at maximum burn rate. The silos are configured based on mass-flow design with the conical bottom section fitted with stainless steel liners.

Washed and crushed coal, 3/4 inch by 0 inch, will be wet ground in rod mills to the proper size. The coal slurry will be generated from the rod mills at a slurry concentration of 58 to 62 percent solids by weight, and will be stored in heated slurry run tanks. Heated slurry will be pumped by the slurry charge pumps to the gasifiers. Also, the system will recover solids from the gasifier soot stream. Recovered solids will be fed back into the gasifier because there is some carbon value and it reduces the solid waste disposal requirements significantly.

Eight operating trains have been proposed for grinding the coal before gasification. Each grinding train supplies ground coal to one of eight operating gasification trains. If one train is shutdown for repair or maintenance, the slurry generated from other grinding trains will be capable of feeding eight gasifiers.

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Rod mills are selected to match the coarse grind (98 to 100 percent less than 14 mesh) used by the Texaco gasifier. Also, tests by mill manufacturers have proven the capability of rod mills to grind Kentucky No. 9 coal to the required size and at the specified 58 to 62 percent solids content. Rod mills have been used in the mineral industry for many decades and have established a reputation for reliability.

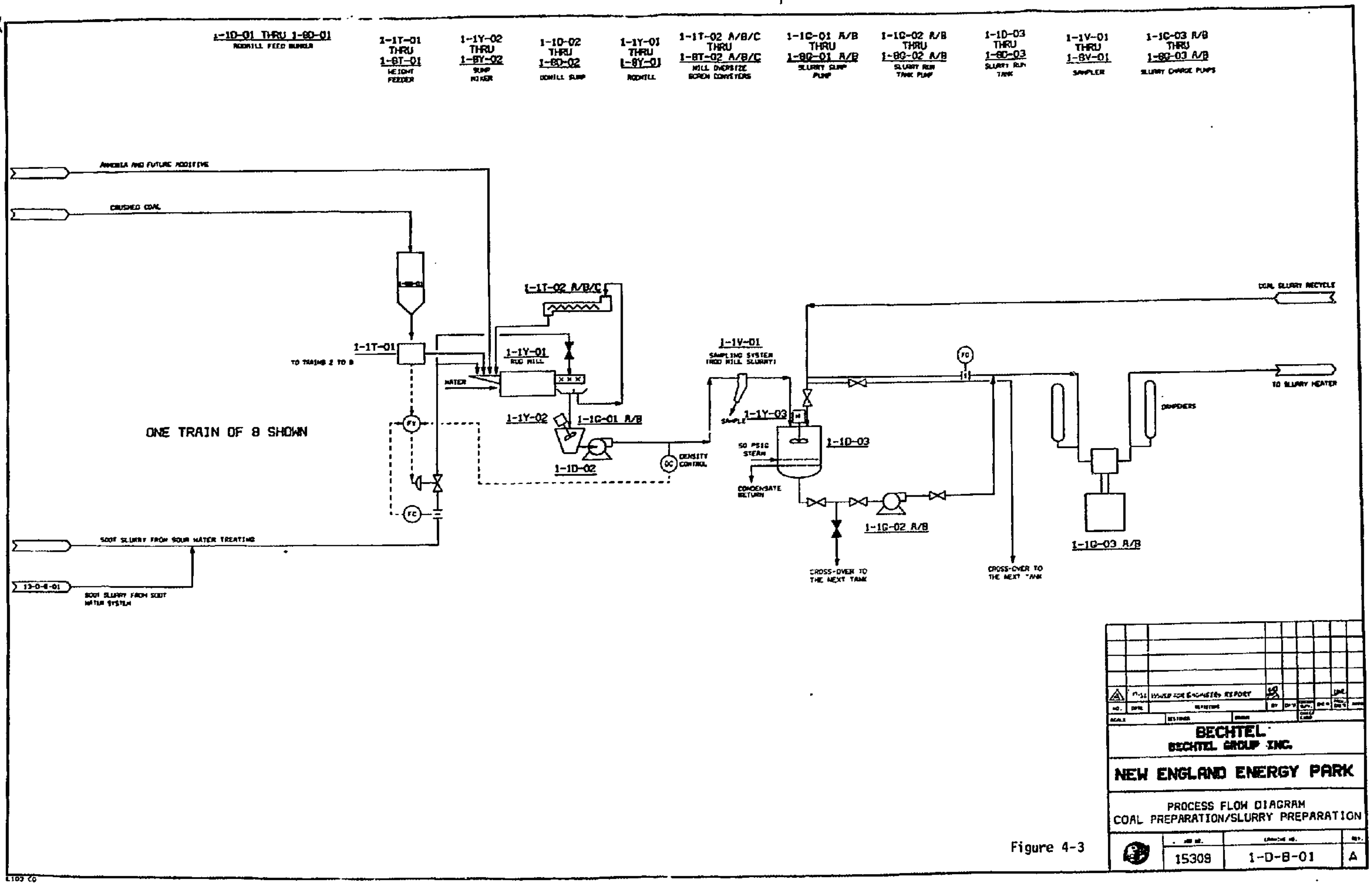
The grinding system incorporates adequate mill volume and power for possible peak requirements caused by higher ash in the coal, because this coal is harder to grind due to its higher ash content. A trommel screen with an opening of about 8 mesh at the discharge end of the rod mill acts as a check point for oversize coal. Plus 8 mesh coal is returned to the mill by screw conveyors. This scheme to handle oversized material from the mill provides a flexible and reliable operation.

The slurry run tank contains an 8-hour stock of prepared and heated slurry ready for use. The rod mills feeding the mix tanks are operated at an optimum and steady grinding rate. An automatic sampling system is provided to take slurry samples at desired intervals.

The above process provides for one grinding train for each gasifier in operation with matched capacities. This permits running an equal number of mills as gasifiers in operation. This flexibility is important because rod mills operate poorly when feed rates are less than the optimum.

(c) Acid Gas Removal

As previously noted, different acid gas removal systems are used for fuel gas, methanol, and SNG. The acid gas treat-



1-1D-01 THRU 1-8D-01
RODMILL FEED BUNKER
1-1T-01 THRU 1-8T-01
WEIGHT FEEDER
1-1Y-02 THRU 1-8Y-02
SUMP MIXER
1-1D-02 THRU 1-8D-02
RODMILL SUMP
1-1Y-01 THRU 1-8Y-01
RODMILL
1-1T-02 A/B/C THRU 1-8T-02 A/B/C
MILL OVERSIZE SCREW CONVEYERS
1-1G-01 A/B THRU 1-8G-01 A/B
SLURRY SUMP PUMP
1-1G-02 A/B THRU 1-8G-02 A/B
SLURRY RUN TANK PUMP
1-1D-03 THRU 1-8D-03
SLURRY RUN TANK
1-1V-01 THRU 1-8V-01
SAMPLER
1-1G-03 A/B THRU 1-8G-03 A/B
SLURRY CHARGE PUMPS
AMMONIA AND FUTURE ADDITIVE
CRUSHED COAL
1-1T-02 A/B/C
1-1T-01
TO TRAINS 2 TO 8
1-1Y-01
ROD MILL
WATER
1-1Y-02
1-1G-01 A/B
1-1D-02
ONE TRAIN OF 8 SHOWN
FY
FC
DC
DENSITY CONTROL
1-1V-01
SAMPLING SYSTEM (ROD MILL SLURRY)
SAMPLE
1-1Y-03
50 PSIG STEAM
CONDENSATE RETURN
1-1D-03
1-1G-02 A/B
CROSS-OVER TO THE NEXT TANK
CROSS-OVER TO THE NEXT TANK
COAL SLURRY RECYCLE
TO SLURRY HEATER
DAMPENERS
1-1G-03 A/B
SOOT SLURRY FROM SOUR WATER TREATING
13-D-B-01
SOOT SLURRY FROM SOOT WATER SYSTEM
BECHTEL
BECHTEL GROUP INC.
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
COAL PREPARATION/SLURRY PREPARATION
15309
1-D-B-01
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Figure 4-3

ment is a Selexol process, designed to desulfurize raw coal gas. The Selexol process, licensed by Allied Chemical Corporation, is a physical absorption process using dimethyl ether of polyethylene glycol as the absorbent. Being a physical absorbent, Selexol will absorb all components in a gas stream as dictated by the equilibrium constant for each component. For this process the objective is to remove sulfur bearing components to the required levels for fuel gas, methanol, and SNG or sulfur equivalent in the treated gas. Both (H_2S and COS) are the key components; these components set the size criteria for the unit for fuel gas. For methanol and SNG units, nearly all of the (H_2S + COS) and an appreciable quantity of CO_2 are absorbed.

Acid Gas Removal System - Fuel Gas

Two acid gas removal units are required to treat the fuel gas quantity. Each unit will handle 50 percent of the flow. Refer to Figure 4-4 for the process flow diagram.

The primary objective is to remove sulfur bearing components (H_2S + COS) to a level of 200 ppmv of sulfur equivalent in the treated fuel gas.

Cooled raw fuel gas from gasification is combined with recycle gas and directed to the bottom of the H_2S absorber. The absorber is a packed tower with a multiple number of beds. Lean solvent (essentially free of absorbed gases) is fed to the top of the absorber. Absorber operating pressure is controlled as close as possible to the normal raw gas pressure for proper operation of the system. Operating temperature is ambient.

Absorption of all gases takes place throughout the length of the absorber. The rich solvent at the bottom will be

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nearly saturated with respect to all the components in the gas. The predominant constituents, however, are H_2S, COS, and CO_2 due to the much higher solubility of these gases in Selexol. There is a slight temperature rise in the tower due to the heat of absorption of the gases. If all feeds were at 100°F, the bottom temperature would be 113°F. The treated gases leave the top of the absorber.

The rich solvent will contain an appreciable amount of dissolved H_2 and CO and it is not desirable that these gases be lost with the sulfur bearing gases from the stripper. Nearly all of these gases are recovered by simply depressurization of the rich solvent and recycling them to the absorber. The flashed gas from depressurization will be rich in the less soluble components (CO & H_2), although it most certainly will contain the more soluble H_2S, COS, and CO_2. The flashed gas is compressed and recycled to the absorber. Flashing the solvent prior to stripping and recycling the flashed gases helps to enrich the sulfur rich gas since it will not contain the recycled gases which are lean in sulfur.

There is considerable energy in the high pressure rich solvent and therefore the solvent is passed through hydraulic turbines to recover this energy rather than undergoing a simple isentropic expansion. Further, for minimum energy consumption, two stages of expansions are performed rather than a single one.

Rich solvent is passed through the high-pressure turbine to a discharge pressure of 230 psia. Flashed gas and solvent are separated in the high-pressure flash drum. The gas is compressed by the second stage of recycle compressor and recycled to the absorber. The resultant liquid is passed

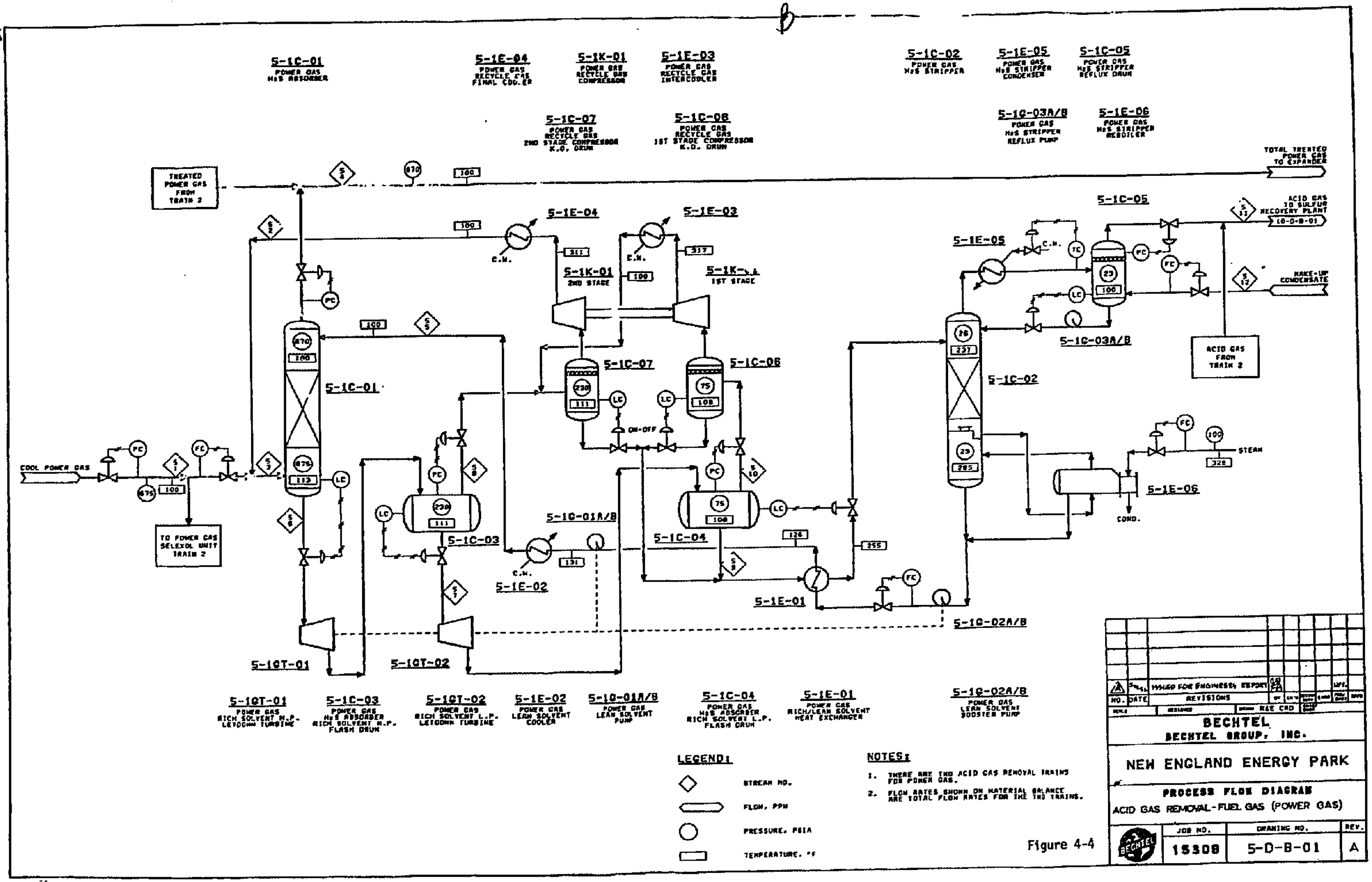
5-1C-01 POWER GAS H2S ABSORBER
5-1E-04 POWER GAS RECYCLE GAS FINAL COOLER
5-1K-01 POWER GAS RECYCLE GAS COMPRESSOR
5-1E-03 POWER GAS RECYCLE GAS INTERCOOLER
5-1C-02 POWER GAS H2S STRIPPER
5-1E-05 POWER GAS H2S STRIPPER CONDENSER
5-1C-05 POWER GAS H2S STRIPPER REFLUX DRUM
5-1C-07 POWER GAS RECYCLE GAS 2ND STAGE COMPRESSOR K.O. DRUM
5-1C-08 POWER GAS RECYCLE GAS 1ST STAGE COMPRESSOR K.O. DRUM
5-1G-03A/B POWER GAS H2S STRIPPER REFLUX PUMP
5-1E-06 POWER GAS H2S STRIPPER REBOILER
TREATED POWER GAS FROM TRAIN 2
TOTAL TREATED POWER GAS TO EXPANDER
ACID GAS TO SULFUR RECOVERY PLANT
MAKE-UP CONDENSATE
ACID GAS FROM TRAIN 2
COOL POWER GAS
TO POWER GAS SELEXOL UNIT TRAIN 2
2ND STAGE
1ST STAGE
ON-OFF
STEAM
COND.
C.W.
5-1GT-01 POWER GAS RICH SOLVENT H.P. LETDOWN TURBINE
5-1C-03 POWER GAS H2S ABSORBER RICH SOLVENT H.P. FLASH DRUM
5-1GT-02 POWER GAS RICH SOLVENT L.P. LETDOWN TURBINE
5-1E-02 POWER GAS LEAN SOLVENT COOLER
5-1G-01A/B POWER GAS LEAN SOLVENT PUMP
5-1C-04 POWER GAS H2S ABSORBER RICH SOLVENT L.P. FLASH DRUM
5-1E-01 POWER GAS RICH/LEAN SOLVENT HEAT EXCHANGER
5-1G-02A/B POWER GAS LEAN SOLVENT BOOSTER PUMP
LEGEND:
STREAM NO.
FLOW, PPH
PRESSURE, PSIA
TEMPERATURE, °F
NOTES:
1. THERE ARE TWO ACID GAS REMOVAL TRAINS FOR POWER GAS.
2. FLOW RATES SHOWN ON MATERIAL BALANCE ARE TOTAL FLOW RATES FOR THE TWO TRAINS.
ISSUED FOR ENGINEERING REPORT
NO. DATE REVISIONS
BECHTEL
BECHTEL GROUP, INC.
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
ACID GAS REMOVAL-FUEL GAS (POWER GAS)
JOB NO. 15308
DRAWING NO. 5-D-B-01
REV. A

Figure 4-4

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through the low-pressure turbine to a discharge pressure of 75 psia. The flashed gas and solvent from the low pressure turbine are separated in the low-pressure flash drum. The gas is compressed to 235 psia by the first stage of the recycle compressor, cooled, and discharged to the second stage of the compressor where it combines with the high-pressure flashed gas and compressed to the absorber inlet pressure.

The low-pressure solvent is preheated by heat exchanging with hot-stripped solvent from stripper and fed to the top of the stripper. The dissolved gases are stripped out of the solvent by steam generated in the reboiler at the bottom of the stripper. The stripper operating pressure is about 26 psia (top) which is the back pressure caused by the sulfur recovery plant. The stripper is also a packed column with multiple beds.

Steam and stripped gases are cooled by the stripper condenser to about 100°F. Condensate is refluxed to the stripper while the nearby dry sulfur bearing gases are sent to the sulfur recovery plant.

Stripped solvent from the bottom is cooled in the rich/lean solvent heat exchanger, further cooled to 100°F in the lean solvent cooler, and pumped to the top of the absorber. The power produced by the hydraulic turbines is used to power the pumps recirculating the Selexol between pressure levels of 26 psia and 675 psia.

The Selexol solution is maintained with about 5 percent (wt) water to reduce the boiling temperature at the bottom of the stripper and thereby reduce degradation of the solvent. At the 5 percent (wt) concentration, more water will

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be lost with the total gas streams than enters with the raw gas streams and therefore, a small continuous amount of water makeup is required to the system.

Acid Gas Removal Systems - Methanol and SNG

Two identical but separate acid gas removal systems are required for the methanol and SNG plants. Each plant is comprised of one H_2S removal and two CO_2 removal trains.

The Selexol process is used to remove all sulfur compounds and most of the CO_2 from the syngas. Removal of sulfur compounds is necessary to avoid catalyst poisoning in subsequent processing units. The CO_2 is removed to a level in the syngas which is tolerable by the subsequent processing units. For H_2S removal, refer to Figure 4-5 and for CO_2 removal, refer to Figure 4-6.

The primary objective is to remove essentially all sulfur bearing components (H_2S and COS) to a level of 0.1 ppmv of sulfur equivalent in the treated gas and to remove sufficient CO_2 to result in a final gas having 3.0 percent CO_2. A secondary objective is to produce a sulfur rich waste gas having approximately 25 percent (H_2S + COS) which can readily be accepted by the standard Claus Sulfur recovery plant. A third objective is to limit the equivalent sulfur in the vented CO_2 waste gas to 20 ppmv.

These three objectives are met by taking advantage of the fact that H_2S is much more soluble than CO_2 in Selexol and by employing two stages of absorption. The first stage is designed to remove all the sulfur bearing compounds and to obtain the required sulfur concentration in the sulfur rich waste gas and the second stage is designed to meet the treated gas requirement with respect to sulfur and CO_2. Separate Selexol solutions are used for each stage.

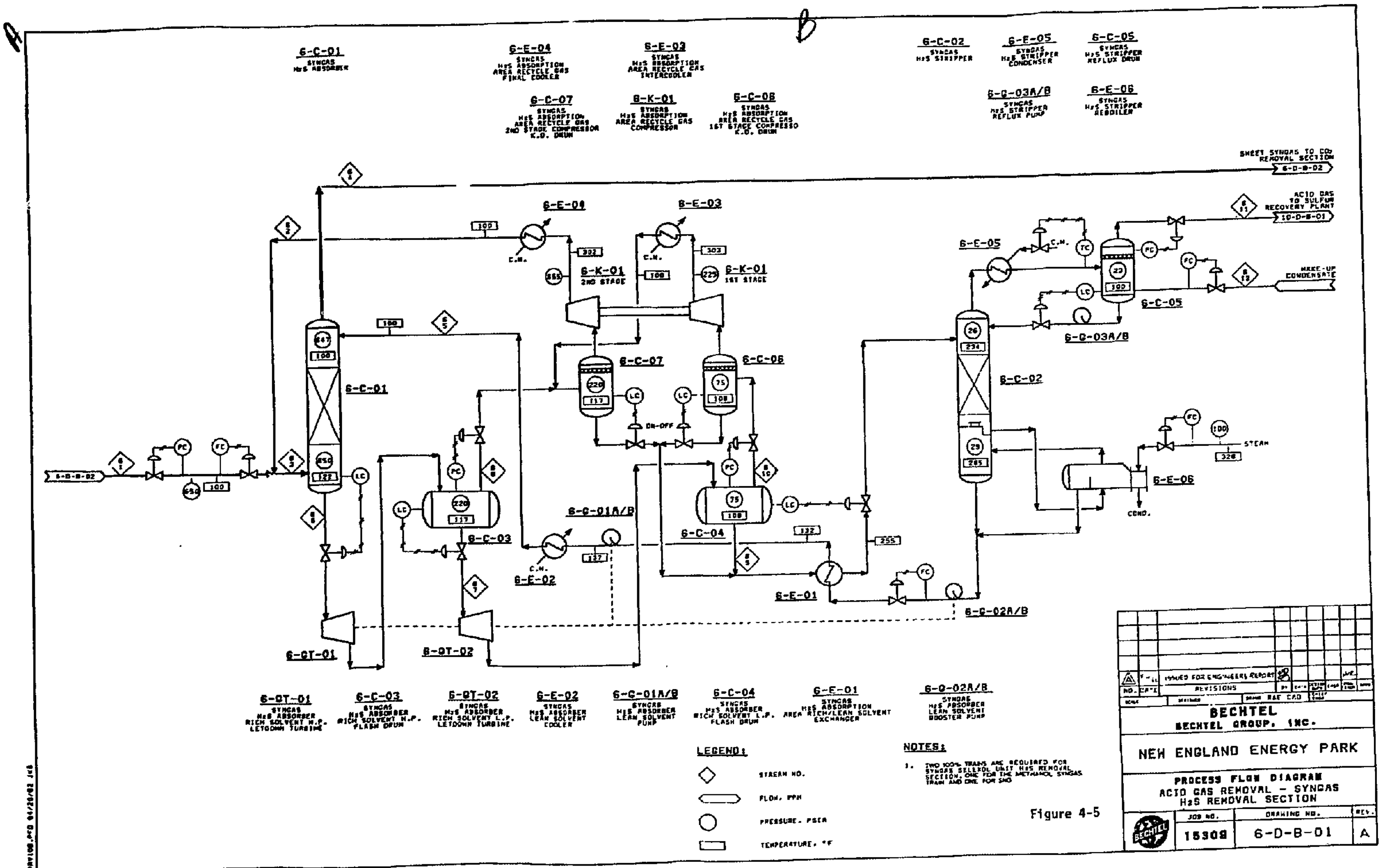
6-C-01
SYNGAS H2S ABSORBER
6-E-04
SYNGAS H2S ABSORPTION AREA RECYCLE GAS FINAL COOLER
6-E-03
SYNGAS H2S ABSORPTION AREA RECYCLE GAS INTERCOOLER
6-C-07
SYNGAS H2S ABSORPTION AREA RECYCLE GAS 2ND STAGE COMPRESSOR K.O. DRUM
6-K-01
SYNGAS H2S ABSORPTION AREA RECYCLE GAS COMPRESSOR
6-C-08
SYNGAS H2S ABSORPTION AREA RECYCLE GAS 1ST STAGE COMPRESSOR K.O. DRUM
6-C-02
SYNGAS H2S STRIPPER
6-E-05
SYNGAS H2S STRIPPER CONDENSER
6-C-05
SYNGAS H2S STRIPPER REFLUX DRUM
6-G-03A/B
SYNGAS H2S STRIPPER REFLUX PUMP
6-E-06
SYNGAS H2S STRIPPER REBOILER
SWEET SYNGAS TO CO2 REMOVAL SECTION
6-D-B-02
ACID GAS TO SULFUR RECOVERY PLANT
10-D-B-01
MAKE-UP CONDENSATE
STEAM
COND.
6-GT-01
SYNGAS H2S ABSORBER RICH SOLVENT H.P. LETDOWN TURBINE
6-C-03
SYNGAS H2S ABSORBER RICH SOLVENT H.P. FLASH DRUM
6-GT-02
SYNGAS H2S ABSORBER RICH SOLVENT L.P. LETDOWN TURBINE
6-E-02
SYNGAS H2S ABSORBER LEAN SOLVENT COOLER
6-G-01A/B
SYNGAS H2S ABSORBER LEAN SOLVENT PUMP
6-C-04
SYNGAS H2S ABSORBER RICH SOLVENT L.P. FLASH DRUM
6-E-01
SYNGAS H2S ABSORPTION AREA RICH/LEAN SOLVENT EXCHANGER
6-G-02A/B
SYNGAS H2S ABSORBER LEAN SOLVENT BOOSTER PUMP
LEGEND:
STREAM NO.
FLOW, PPH
PRESSURE, PSIA
TEMPERATURE, °F
NOTES:
1. TWO 100% TRAINS ARE REQUIRED FOR SYNGAS SELEXOL UNIT H2S REMOVAL SECTION, ONE FOR THE METHANOL SYNGAS TRAIN AND ONE FOR SNG
ISSUED FOR ENGINEERING REPORT
REVISIONS
BECHTEL
BECHTEL GROUP, INC.
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
ACID GAS REMOVAL - SYNGAS
H2S REMOVAL SECTION
JOB NO.
15309
DRAWING NO.
6-D-B-01
REV.
A

Figure 4-5

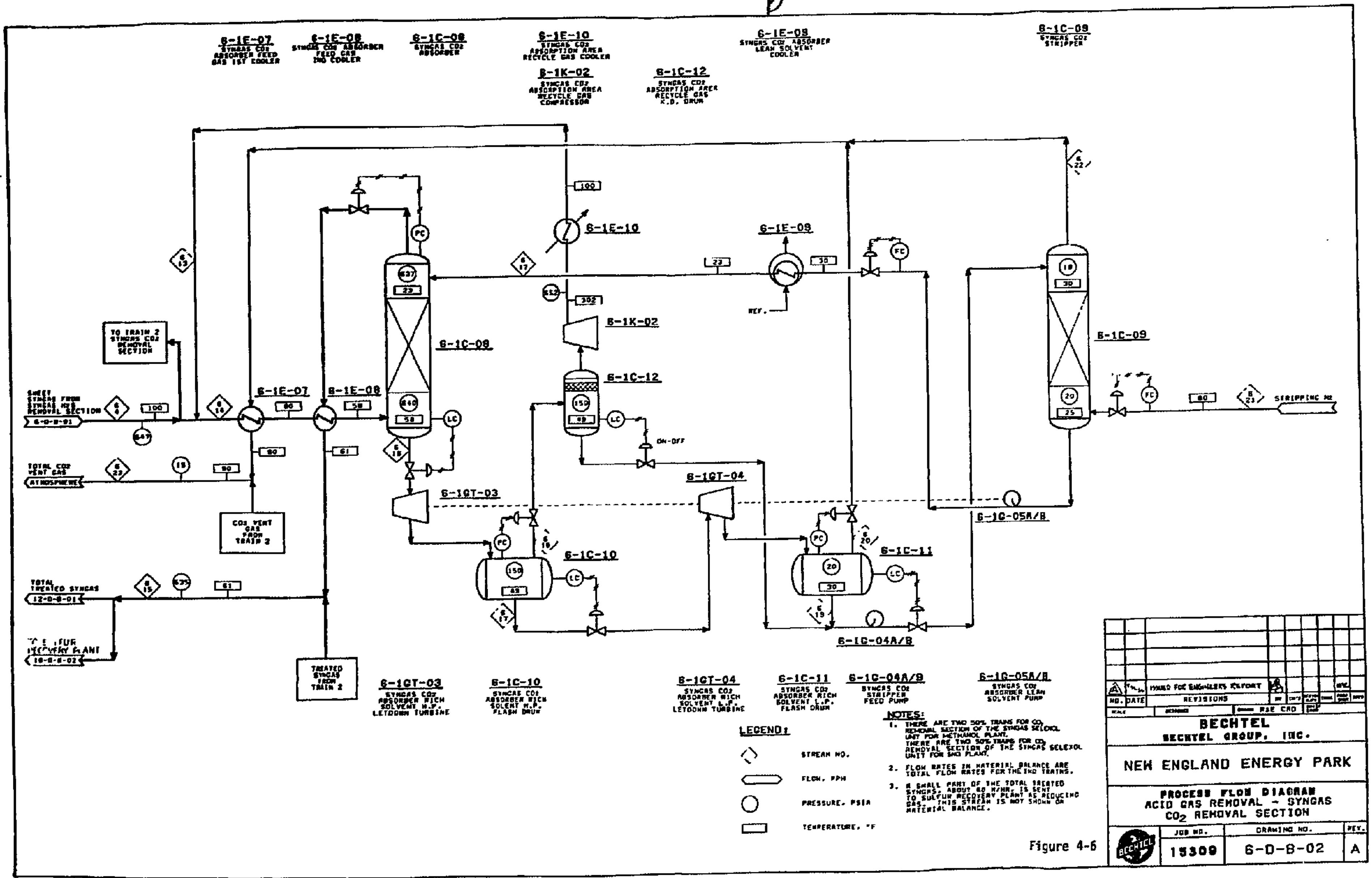

Figure 4-6

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Some CO_2 will be removed with the (H_2S + COS) in the first absorber. The quantity of CO_2 removed relative to the quantity of (H_2S + COS) is a function of the CO_2 composition relative to the (H_2S + COS) composition in the raw syngas.

The raw syngas has a CO_2/(H_2S + COS) ratio such that the required sulfur composition in the sulfur rich waste gas can be obtained without any further concentration of these waste gases.

Based on the maximum equipment size criteria of a 13-foot diameter, one first stage system (H_2S + COS removal) and two second stage systems (CO_2 removal) are required.

The sequence of operation of the H_2S and COS removal train for the methanol/SNG case is similar to the system used for the fuel gas H_2S and COS removal train. Design specifications and criteria are different for the above systems in order to accommodate the difference in level of permissible sulfur compounds in the exit gas streams. Therefore, for detailed process descriptions of the H_2S and COS removal systems for methanol/SNG, refer to fuel gas acid gas removal.

Downstream of the H_2S and COS removal train, the partially treated gases leave the top of the absorber and go to the second absorption stage for CO_2 removal. The second absorption stage (CO_2 removal) is nearly identical to the first stage.

(d) Shift Conversion

Separate shift conversion process units will be required to stoichiometrically adjust the hydrogen to CO ratio for sub-

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sequent methanol and SNG synthesis reactions. Each shift conversion unit will be designed for 100 percent throughput.

The raw gas stream entering the methanol unit shift conversion train reacts in the presence of catalysts to produce hydrogen and CO_2. The optimum feed for methanol synthesis should have a slight excess of hydrogen over the stoichiometric requirement of a 2 to 1 hydrogen to carbon monoxide ratio.

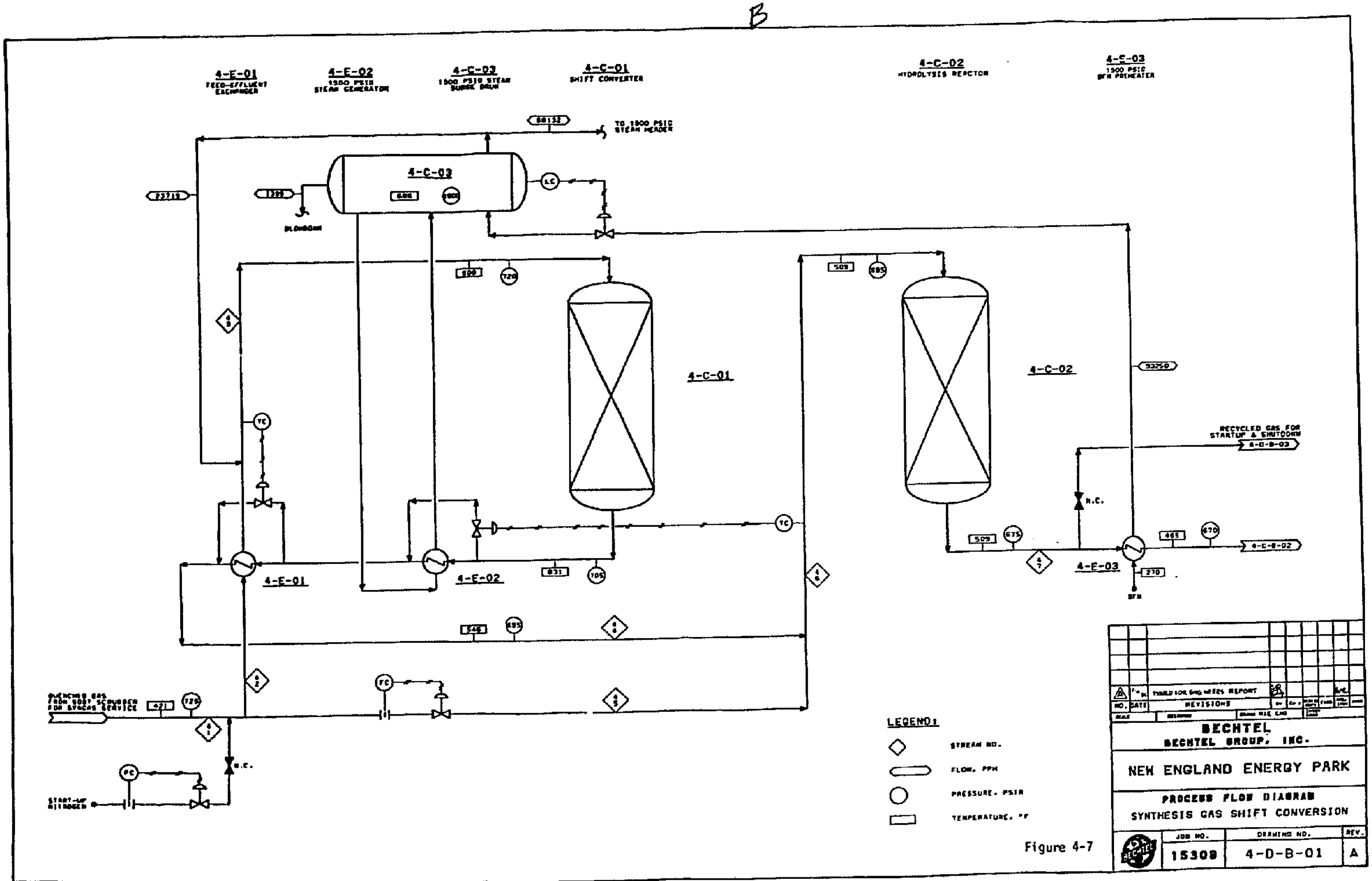
The raw gas stream entering the SNG unit shift conversion train is also subjected to a catalytic reaction to produce hydrogen and CO_2. The optimum feed for SNG synthesis on the other hand should have a slight excess of a 3 to 1 hydrogen to carbon monoxide ratio.

The stoichiometric reaction is accomplished by the water gas shift reaction:

$$CO + H_2O = CO_2 + H_2$$

The raw gas coming from the gasifier quench section has been saturated with water vapor to yield a steam-to-dry-gas ratio of 1.2 to 1. In passing through the catalytic shift reactor, some of the carbon monoxide reacts with steam to produce hydrogen. Approximately 42 percent of the raw gas is bypassed around the shift converter in order to control the amount of hydrogen production. The recombined stream contains 3 percent of excess hydrogen, after CO_2 removal, for the methanol synthesis and methanation reactions.

As illustrated in Figure 4-7, the raw gas is first heated to increase the reaction rate, and then introduced into the



4-E-01
FEED-EFFLUENT EXCHANGER
4-E-02
1500 PSIG STEAM GENERATOR
4-C-03
1500 PSIG STEAM BUBBLE DRUM
4-C-01
SHIFT CONVERTER
4-C-02
HYDROLYSIS REACTOR
4-E-03
1500 PSIG BFW PREHEATER
TO 1500 PSIG STEAM HEADER
BLOWDOWN
RECYCLED GAS FOR STARTUP & SHUTDOWN
4-D-B-02
START-UP NITROGEN
LEGEND:
STREAM NO.
FLOW, PPH
PRESSURE, PSIA
TEMPERATURE, °F
BECHTEL
BECHTEL GROUP, INC.
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
SYNTHESIS GAS SHIFT CONVERSION
JOB NO.
15309
DRAWING NO.
4-D-B-01
REV.
A

Figure 4-7

fixed-bed catalytic reactor. The reaction is highly exothermic, and gases leaving the reactor pass through a waste-heat boiler that generates steam at 1500 psig. In addition to hydrogen sulfide, the raw gas also contains carbonyl sulfide, which is not easily removed in the acid gas removal system. A portion of the carbonyl sulfide in the raw gas is converted to hydrogen sulfide in the shift reactor. A hydrolysis reactor is required after the shift reactor to convert most of the remaining COS to H_2S so that the acid gas removal unit can reduce the total sulfur content of the synthesis gas to 0.1 ppmv. The hot reactor effluent gases pass through waste-heat boilers to generate 85 psig and 50 psig steam. After passing through waste-heat boilers, the gas traverses several knockout drums and coolers before acid gas removal.

During start-up and prolonged shutdowns, activation of catalyst and initiation of reaction kinetics requires that the reaction temperature for shift conversion be elevated before stoichiometric reaction of CO and H_2O can be effected. This evaluation of temperature of the process reactants is accomplished externally by preheating the incoming feed in a fired start-up heater.

During start-up, nitrogen from the oxygen plant is compressed and then preheated in a fired heater. Preheated nitrogen is then introduced to the shift reactors. Once reaction temperature is achieved, preheated reactants are gradually introduced and nitrogen withdrawn. Since shift conversion is a highly exothermic reaction, the start-up heating system is discontinued after the reaction becomes self-sustaining.

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(e) Methanol/Methanation Synthesis

The methanol synthesis plant employs Lurgi low-pressure technology. As shown in Figure 4-8, the shift and purified synthesis gas is compressed to 750 psig and combined with the recycle gas. The combined gas stream is preheated by exchange with the hot reactor outlet gas before entering the two parallel reactors. The reactors contain catalyst-filled tubes, with temperature control of the synthesis reactions achieved by steam generation on the vessel-shell side. The gas streams leaving the reactors are cooled by the inlet gas streams and air coolers before entering a common separator.

Condensed crude methanol is sent to purification with the gas returning to the reactors via the recycle compressor. The ratio of recycled gas to fresh feed is approximately 4 to 1. A purge stream is taken off the gas from the separator to prevent buildup of inerts. The purge gas is used as fuel in the combined cycle power plant.

The crude methanol is freed of low boiling compounds (methyl formate, dimethyl ether, and others) in the light ends column. This overhead gas stream is also used as fuel gas. The methanol is then distilled to chemical-grade purity in two columns; the first operating at 100 psig and the second at atmospheric pressure. The overhead streams from each column constitute the methanol product, with the first column overhead product reboiling the second column, and the first column bottoms feeding the second column. The two product streams are combined, cooled, and pumped to storage. The water separated from this product, consisting of the bottoms from the second column, contains traces of methanol and high-boiling impurities and is pumped to the sour water stripper.

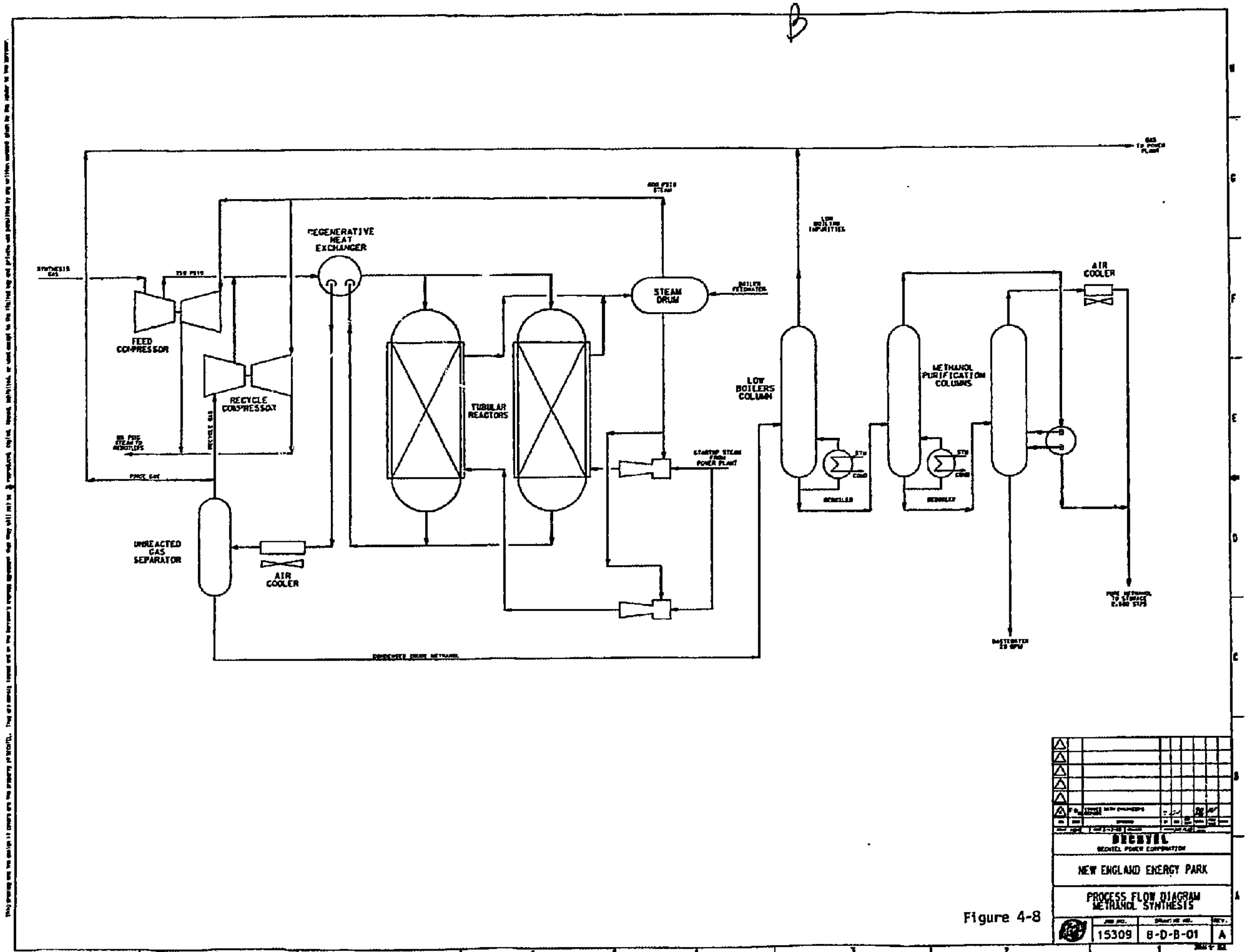

REGENERATIVE HEAT EXCHANGER
FEED COMPRESSOR
RECYCLE COMPRESSOR
UNREACTED GAS SEPARATOR
AIR COOLER
TUBULAR REACTORS
STEAM DRUM
LOW BOILERS COLUMN
METHANOL PURIFICATION COLUMNS
AIR COOLER
SYNTHESIS GAS
GAS TO POWER PLANT
LOW BOILING IMPURITIES
BOILER FEEDWATER
STARTUP STEAM FROM POWER PLANT
PURGE GAS
RECYCLE GAS
BECHTEL
BECHTEL POWER CORPORATION
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
METHANOL SYNTHESIS
15309
B-D-B-01
A

Figure 4-8

Energy requirements of the methanol synthesis and purification units are minimized by the efficient use of steam generated in the synthesis reactor for feed and recycle compression and to supply heat for the distillation reboilers. The two column methanol distillation process also conserves steam by using the overhead from the high-pressure column for reboiling the low-pressure column.

The objective of the methanation unit is production of synthetic natural gas from synthesis gas. The feed gas is methanated according to the following chemical reactions:

$$CO + 3H_2 = CH_4 + H_2O$$
$$CO_2 + 4H_2 = CH_4 + 2H_2O$$

The methanation process scheme is represented in Figure 4-9. Each reaction is exothermic. Most of the heat of reaction is recovered as high pressure saturated steam.

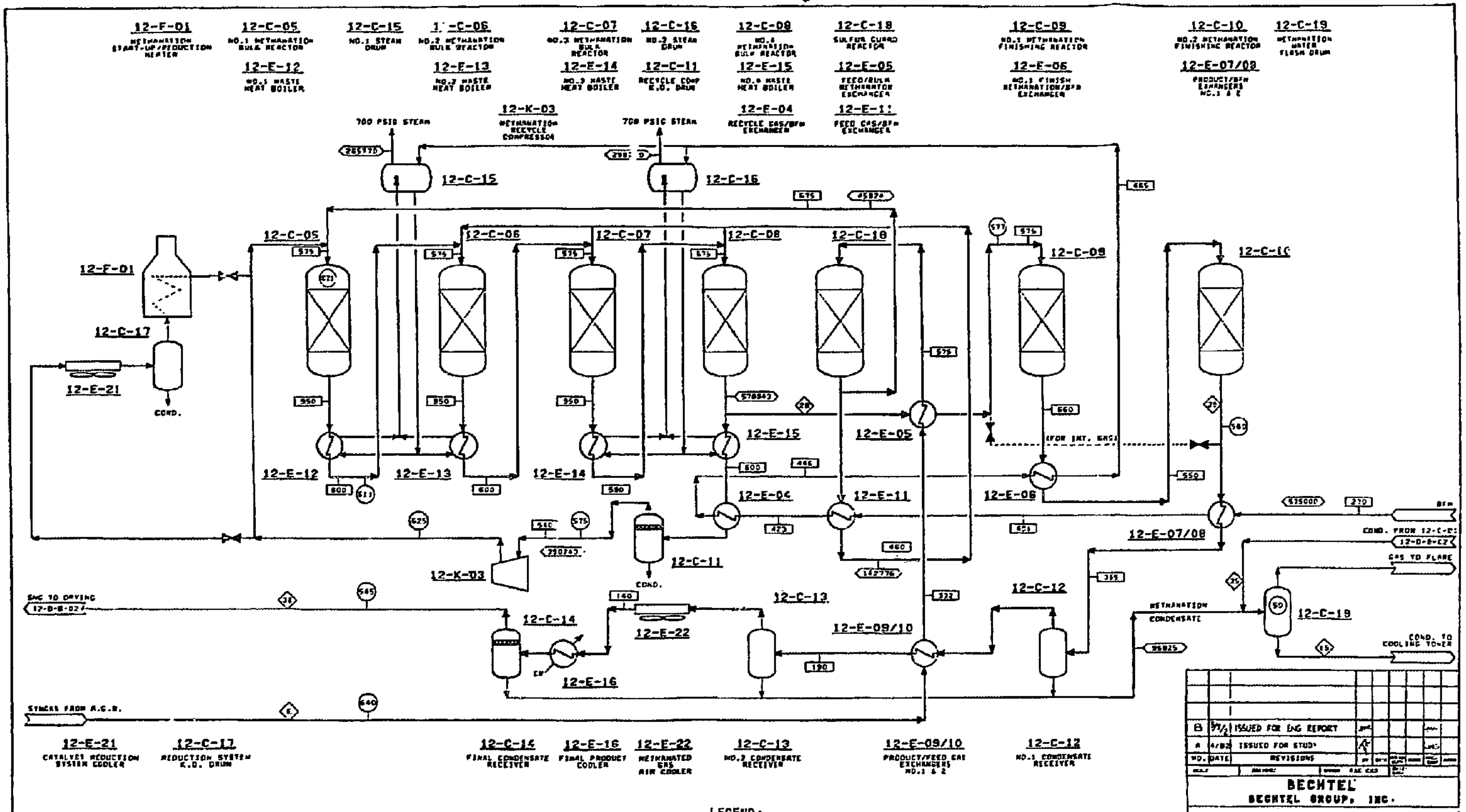
(f) Oxygen Plant

This plant supplies 8500 tpd of oxygen to the gasifiers at a pressure of 900 psig which is 150 psi above the gasifier operating pressure. The oxygen is 99.5 percent pure. This is considered to be the optimum purity based upon the subsequent production of methanol and SNG. Oxygen supply temperature is 275°F. This temperature strikes a balance between the capital costs associated with interstage cooling versus the costs of the compressor prime mover.

Several companies offer oxygen production plants of similar design. The flow diagram is shown on Figure 4-10. Four equal trains of 2125 tons per day form the basis of the conceptual design. The power requirements for making oxygen are significant. The main air compressor requires approximately 30,000 hp and the oxygen compressor requires approximately 14,000 hp. Three trains are turbine-driven and one train is motor-driven to facilitate startup.

In each train, ambient air is filtered and then compressed in stages, using water-cooled inter- and after-coolers. The air is further cooled by cold effluent nitrogen and oxygen in reversing heat exchangers. Carbon dioxide and water are frozen out in the heat exchanger passages as the air is cooled. After cooling in a liquefier exchanger, the air is subjected to high- and low-pressure distillation where oxygen and impure nitrogen are separated by fractionation. Nitrogen from the high-pressure column passes through a turbo-expander for power recovery. The oxygen product is taken from the low-pressure column and through the liquefier and reversing exchangers to the oxygen compressor. Oxygen compression to 900 psig is carried out in intercooled stages to hold the oxygen temperature of 275°F. Oxygen from the last compressor stage goes to the gasifier without aftercooling or intermediate storage. Liquid oxygen can be produced at a rate of 64 tons per day. Total liquid oxygen storage is equal to the daily gaseous production from one train, i.e., 2,125 tons.

High pressure saturated steam is required to drive the air and oxygen compressors of trains 1, 2, and 3. Turbine exhaust steam is condensed and pumped back to the combined cycle plant condensate system. Cooling water from the NEEP cooling towers is used for compressor interstage cooling, condenser cooling water, and miscellaneous uses. Good quality, treated water is required for the cooling and scrubbing of the air in the direct contact air coolers. A closed cooling water system minimizes the consumption of water. A portion of the system flow is filtered and demineralized continuously.



STREAM / COMPONENT		6		15		28		29		35		26	
NAME	M.W.	MPH	M.%	MPH	M.%	MPH	M.%	MPH	M.%	MPH	M.%	MPH	M.%
CO	28.01	4851	22.9			5	.08	TRACE				TRACE	
CO_2	44.01	316	1.49			215	3.44	55	.98			55	0.98
H_2	2.02	15771	74.33			801	12.82	150	2.68			150	2.68
CH_4	16.04	75	.35			5031	80.51	5199	92.82			5199	92.82
Inerts	28	197	.93			197	3.15	197	3.52			197	3.52
TOTAL DRY		21210	100.00			6249	100.00	5601	100.00			5601	
H_2O	18.02	9		5374		5056		5281		2.5		9.9	
TOTAL WET		21219		5374		11301		10882		2.5		5610.9	
TOTAL LB/HR		188600		96825		188600		188600		45		91620.0	
M.W.		8.89		18.02		16.68		17.17		18.02		16.35	
TEMP °F		75		100		860		575		100		100	

BADD.BRD

NO.	DATE	REVISIONS
B	9/1/1	ISSUED FOR ENG REPORT
A	4/82	ISSUED FOR STUDY

BECHTEL
BECHTEL GROUP, INC.

NEW ENGLAND ENERGY PARK

PROCESS FLOW DIAGRAM
METHANATION

JOB NO. 15300 | DRAWING NO. 12-D-B-01 | REV. B

Figure 4-9

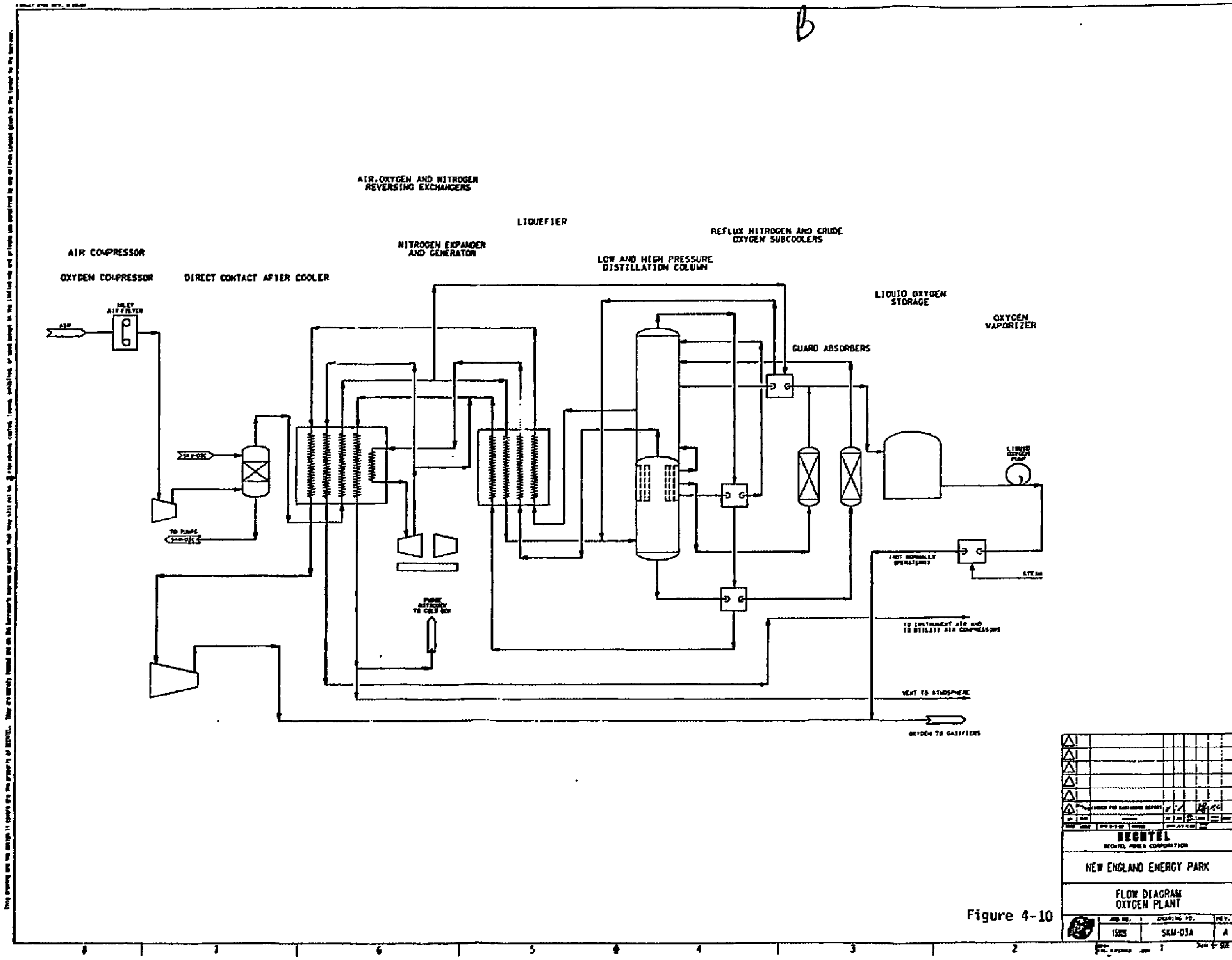


Figure 4-10

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In addition to oxygen, the plant produces nitrogen which is used for solvent regeneration in the acid gas removal system and for the gas supply for all pneumatic instrumentation. About one-half of the nitrogen is consumed by solvent regeneration; excess nitrogen is expanded through a power turbine driving a 4160-volt generator. Liquid oxygen storage is isolated from other equipment by an earth dike.

(g) Combined-Cycle Power Plant

The power production facilities selected for the New England Energy Park use gas-turbine combined-cycle equipment. Except for the heat recovery steam generators (HRSGs), the power plant uses state-of-the-art, commercially available technology and equipment. Gas turbine combined cycle equipment of the type and rating required for NEEP has been in service in more than 20 plants since 1968. The power plant is shown schematically in Figure 4-11. The basic design is to combust clean fuel gas in the gas turbines, then route the hot exhaust gases from the gas turbines through HRSGs. The steam produced in the five HRSGs is collected and routed to a single steam turbine generator. The HRSGs also superheat saturated steam from the gasifier heat recovery boilers to drive three of the four trains of oxygen plant turbines and superheat steam produced in the SNG plant for injection into the steam turbine.

The power plant is base-loaded with five gas turbine generating units, five heat recovery steam generators, and a single steam turbine-generator. The power plant will have a nameplate rating of 645 MW gross, with each gas turbine-generator rated at 79 MW at 90°F air temperature, and the steam turbine-generator rated at 250 MW.

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In the nominal operating mode, the plant consumes 108 billion Btu per day of medium Btu (285 Btu/sfc) gas, which is two-thirds of the raw gas.

The power plant is located adjacent to the oxygen plant. The five gas turbine generators are arranged in a line at ground level with five heat recovery steam generators to the rear. Platforms provide access to bearings, local instrument access ports, and other operating and maintenance points. The steam turbine generator is mounted on an elevated concrete pedestal in a separate area with the condenser and condensate equipment below. The deaerator and motor-driven feedwater pumps are positioned between the heat recovery steam generator, with the deaerator elevated and the pumps at ground level. The demineralizers are located in the water treatment room. Other auxiliaries are also located in the building. There is a central control room at the operating floor level, three floors above the basement level. An elevator adjacent to the control room allows access from the lower levels.

Gas Turbine Generators

Each of the five gas turbines has a control valve station that taps into the header for feeding fuel gas to the combustor. Steam from steam turbine extraction is injected into the cumbustors to reduce NO_x emission in the exhaust gases. High-purity steam minimizes the introduction of solids into the gas stream. Each gas turbine generator consists of three major rotating components mounted on a single shaft: a compressor, a turbine, and a generator. For startup, each machine requires an electric motor of 800 horsepower to bring it up to power sustaining speeds, after which the motor is disengaged. A turning gear is needed

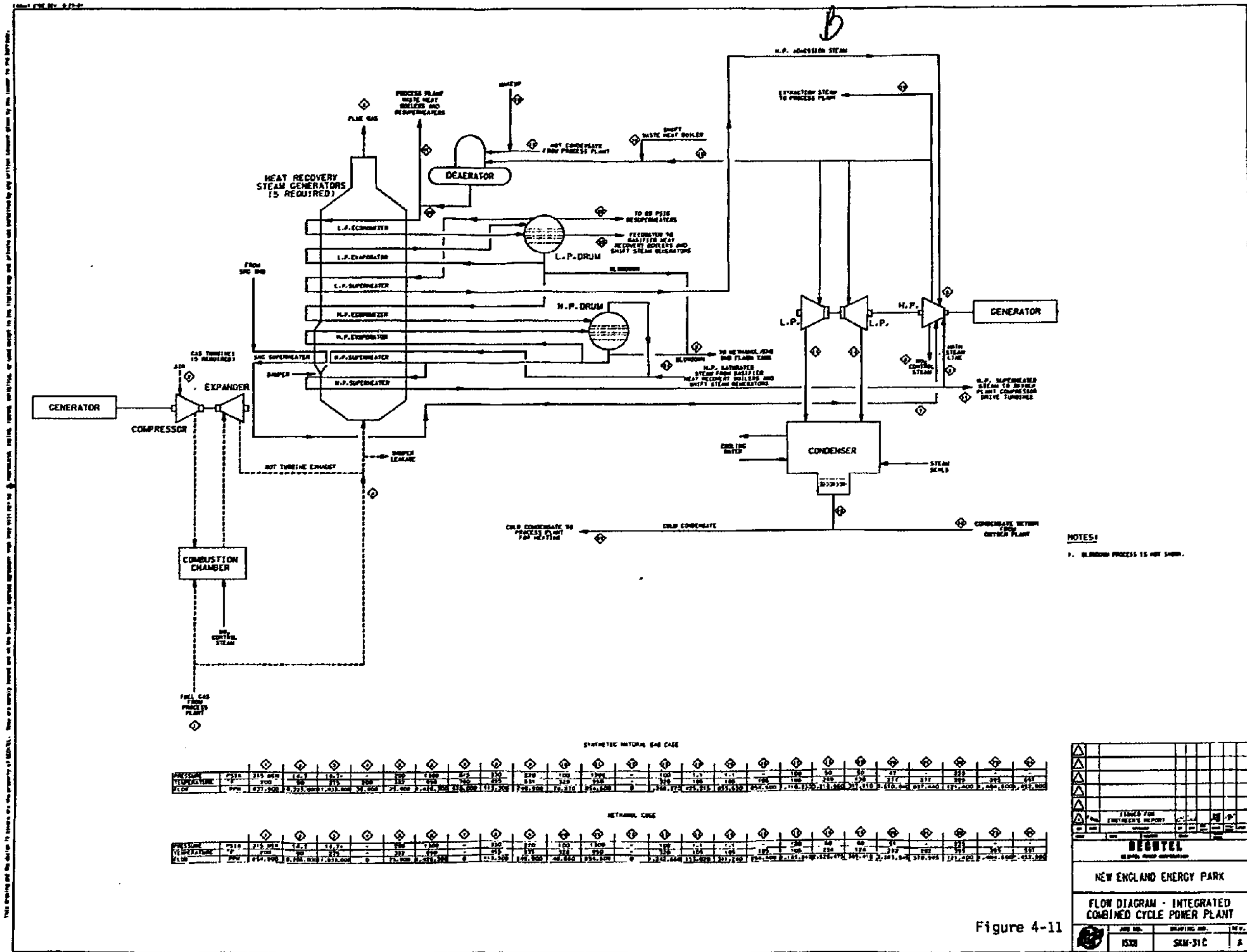
HEAT RECOVERY
STEAM GENERATORS
(5 REQUIRED)
DEAERATOR
L.P. DRUM
H.P. DRUM
GENERATOR
COMPRESSOR
EXPANDER
COMBUSTION CHAMBER
L.P.
H.P.
CONDENSER
GENERATOR
NOTES:
NEW ENGLAND ENERGY PARK
FLOW DIAGRAM - INTEGRATED
COMBINED CYCLE POWER PLANT
BECHTEL
SKM-31C

Figure 4-11

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after shutdown to protect the shaft from uneven cooling. During operation, the air from the compressor is fed to a combustor, where it mixes with fuel gas and is burned. The hot gases (nominally 2,000°F) enter the gas turbines, where they expand through the blades and dissipate energy. Firing temperatures above 2,000°F (state-of-the-art capability) have not been considered for this plant. The gas turbines exhaust into the heat-recovery steam generator at a pressure slightly above atmospheric and at a temperature of approximately 1,000°F.

The combustors of one of the gas turbines will be designed to accept methanol as well as fuel gas. The methanol fuel system will permit this gas turbine to be operated simple cycle in support of plant start-up.

The gross electric generating capacity of the plant increases from about 600 MW at 68°F to about 700 MW at 20°F. Operation at 700 MW requires about 14 percent additional fuel. Fuel gas cooling and acid gas removal equipment is expected to have a stretch capacity of 105 percent. The additional 9 percent fuel is supplied by introducing syngas into the fuel gas steam upstream of the combustors. At the 700 MW and 20°F ambient condition, firing temperatures remain at 2000°F. The plant is capable of generating still more power at higher firing temperatures, but such operation reduces plant availability due to increased schedule maintenance and reduces reliability due to an expected increase in unscheduled outages.

Heat Recovery Steam Generators

Interfacing the gas system and the steam system, the HRSGs convert the sensible heat in the exhaust gases to steam.

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The HRSGs employed are heat-exchange vessels similar to the convection stages of a conventional boiler, and they operate at high efficiency because the low sulfur level in the fuel gas permits a low HRSG exhaust temperature and because the heat transfer surfaces stay clean burning the clean fuel gas. Plates in the gas passes function as economizers, evaporators, and superheaters. High pressure throttle steam is produced at 950°F and 1,350 psig, while the hot exhaust gas is cooled from 1,000°F to approximately 275°F.

The HRSGs selected are natural draft units, and the design has incorporated gas turbine back-pressure requirements. Dampers at the gas-turbine exhausts allow the HRSGs to be bypassed at start-up or in the event of steam system shutdown, diverting the gases to the exhaust stack.

The superheating of saturated steam from the SNG plant in the HRSGs necessitates the supplementary firing of fuel gas into the gas turbine exhausts. A portion of the fuel gas bypasses the gas turbine during this operating mode. No additional air is required to be supplied to the gas turbine exhaust. Major suppliers of combined cycle equipment have experience with the supplemental firing of HRSGs. When there is no surplus steam from the SNG plant, dampers in the HRSGs isolate the SNG superheat coils from the gas turbine exhaust flow. EPRI Report AP-1429, dated June 1980, concluded that overall plant efficiency could be improved by supplemental HRSG firing if steam conditions were increased. No increase in steam conditions were assumed for this report.

Steam Turbine Generator

The turbine selected for this station is a 250 MW, 3,600 rpm, tandem compound, nonreheat, condensing steam turbine,

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with inlet steam conditions of 1350 psig and 950°F exhausting at 2.25 inches Hg back pressure. The generator that the turbine drives is a three-phase 60-Hz, hydrogen-cooled generator at 13,800-volt output.

Throttle steam is supplied to the steam turbine by five HRSGs connected by a common steam feed header and common turbine admission valves. The electrical output systems of the five gas turbine generators and the one steam turbine generator are integrated to perform as a single system, controlled from a central control room. Automatic steam extraction from the turbine supplies steam for:

- Steam injection to the combustors for NO_x suppression
- Process steam requirements at 85 psig
- Boiler feedwater deaeration

Control Systems

The plant design includes controls for the five gas turbine generators, the five HRSGs, and the steam turbine generator in the main control room. The main control panels for the five gas turbine generator units and the steam turbine generator will be custom designed. The operator will have all capability necessary to control start-up and shutdown of the units and auxiliary systems from the control room.

The relay and logic control cabinets for the gas-turbine units and steam turbine generator unit will be located in the main control room. The relay, logic, and analog controls for the heat recovery steam generators and auxiliary systems will be located in the cable spreading room below the main control room.

Instrument and service gas requirements for the units will be met by two reciprocating nonlubricated gas compressors

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with motor drives, aftercoolers, air receivers, and necessary controls. Each gas compressor will have a capacity of 400 scfm at 100 psig. The service gas supply is nitrogen from the oxygen plant.

Electrical Systems

The main power system consists of the generators, generator breakers on the gas turbine units, and the main stepup transformers. The high voltage side of the main transformers of the gas turbine generators are connected together into one 115-kV tie line to the switchyard. The steam turbine unit is connected to the switchyard through its own tieline.

Condensate and Feedwater System

Steam exhausts through the turbine to a condenser with a back pressure of 2.25 inches Hg absolute and is recycled by the condensate pumps to a deaerator. Boiler feed pumps at the deaerator outlet then supply high-pressure feedwater to heat recovery steam generators.

Three motor-driven 50 percent capacity boiler feed pumps will be provided. Each pump will be equipped with an automatic minimum flow recirculation control system to prevent pump overheating during transient or low load operating conditions. The spare motor-driven boiler feed pump will be piped and valved to provide start-up and full capacity backup to either pump. Auxiliary steam is used for the deaerator at start-up. During normal operation, deaerator heating steam is supplied from the 85 psig steam header. Makeup water is supplied to the condenser from the demineralizer system. Feedwater treatment includes hydrazine, amine, and phosphate injection systems.

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Cooling Water

The cooling tower, process water storage pond, and circulating water pump house, which supply condenser cooling water and service water, are located south of the powerhouse building. The cooling tower basins drain by gravity to the process water storage pond, which serves both as a storage reservoir for the gasification process and as an additional heat sink for the cooling system. The pump house is divided into two sections, one for the power plant and one for the process plant. Each pump house contains two circulating water pumps, of approximately 70,000-gpm capacity, complete with screens and other auxiliaries. Two service water pumps, each with a design capacity of 11,000 gpm, are also located in each pump house. Water for the cooling systems comes directly from the plant raw water supply.

(h) Sulfur Recovery

Sulfur recovery is accomplished by means of the Claus/SCOT process, as shown in Figures 4-12 and 4-13. In the Claus plant, approximately one-third of the acid gas stream is combusted with air in a thermal reactor to produce sulfur dioxide. This stream is then mixed with the balance of the acid gas and routed through three fixed-bed catalytic reactor stages. Sulfur is produced by the reaction of hydrogen sulfide and sulfur dioxide. The resulting elemental sulfur vapor is condensed by cooling the gases to a level below the dewpoint of sulfur. The condensed sulfur is then separated from the uncondensed gases and is stored and shipped in the molten state. The cooling of the gases resulted in generation of appreciable quantities of steam that are partially consumed in the tail gas treatment plant.

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The unreacted gas from the third reactor stage goes to the SCOT tail gas treatment plant. Here, the sulfur compounds in the tail gas are coverted to hydrogen sulfide through hydrogenation and hydrolysis. The hydrogen sulfide is then recovered using a selected amine solvent for recycle to the Claus plant feed. The Claus-SCOT combination recovers 99.9 percent of the feed sulfur. The SCOT tail gas contains approximately 250 ppm of hydrogen sulfide, which is incinerated to form sulfur dioxide before being vented to the atmosphere.

(i) Sour and Soot Water Stripping

Recovery of unreacted carbon and process condensate is effected in two unit operations, the soot water system (Figure 4-14) and the sour water stripping (Figure 4-15).

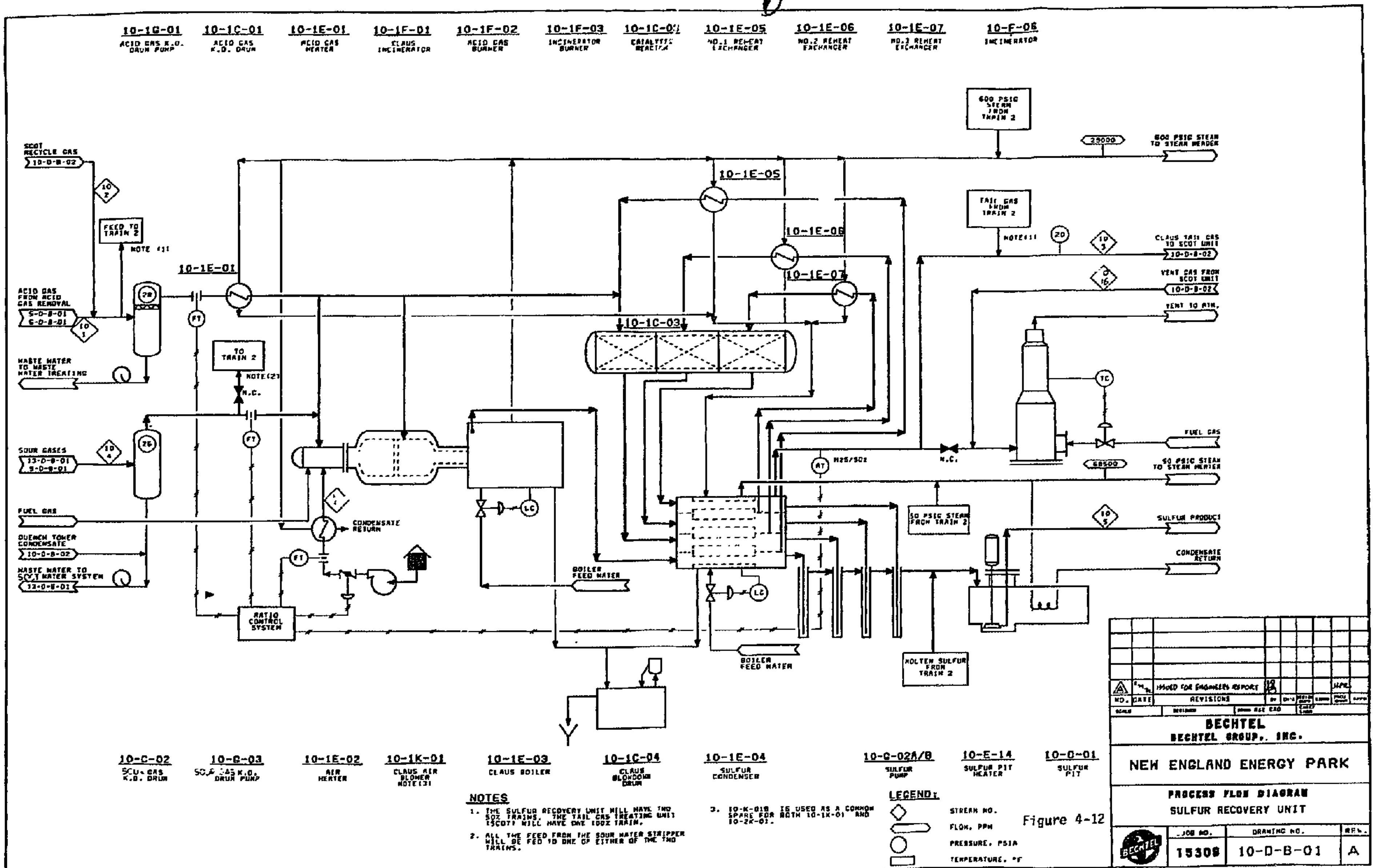
Soot Water System

The gasification system produces the following major aqueous streams:

- A considerable amount of condensate is produced from cooling the gases after adiabatic saturation during scrubbing to remove particulate matter.

- There is substantial blowdown from the gas scrubbers to remove the precipitated particulate matter. This water is known as "soot water." The soot water is actually a 5 percent (wt) slurry of water and solids consisting of about 50 percent of unburned carbon and 50 percent ash.

The condensate is recycled to provide the saturation water in the gas scrubbers. The soot water is ultimately clarified in another plant but prior to clarification, its heat


10-1G-01 ACID GAS K.O. DRUM PUMP
10-1C-01 ACID GAS K.O. DRUM
10-1E-01 ACID GAS HEATER
10-1F-01 CLAUS INCINERATOR
10-1F-02 ACID GAS BURNER
10-1F-03 INCINERATOR BURNER
10-1E-05 NO.1 REHEAT EXCHANGER
10-1E-06 NO.2 REHEAT EXCHANGER
10-1E-07 NO.3 REHEAT EXCHANGER
10-F-06 INCINERATOR
10-1C-03
600 PSIG STEAM TO STEAM HEADER
25000
TAIL GAS FROM TRAIN 2
CLAUS TAIL GAS TO SCOT UNIT
10-D-B-02
VENT GAS FROM SCOT UNIT
VENT TO ATM.
FUEL GAS
50 PSIG STEAM TO STEAM HEADER
68500
SULFUR PRODUCT
CONDENSATE RETURN
50 PSIG STEAM FROM TRAIN 2
MOLTEN SULFUR FROM TRAIN 2
BOILER FEED WATER
RATIO CONTROL SYSTEM
TO TRAIN 2
FEED TO TRAIN 2
SCOT RECYCLE GAS
ACID GAS FROM ACID GAS REMOVAL
WASTE WATER TO WASTE WATER TREATING
SOUR GASES
QUENCH TOWER CONDENSATE
WASTE WATER TO SOUR WATER SYSTEM
10-C-02 SOUR GAS K.O. DRUM
10-G-03 SOUR GAS K.O. DRUM PUMP
10-1E-02 AIR HEATER
10-1K-01 CLAUS AIR BLOWER NOTE(3)
10-1E-03 CLAUS BOILER
10-1C-04 CLAUS BLOWDOWN DRUM
10-1E-04 SULFUR CONDENSER
10-G-02A/B SULFUR PUMP
10-E-14 SULFUR PIT HEATER
10-D-01 SULFUR PIT
NOTES
1. THE SULFUR RECOVERY UNIT WILL HAVE TWO 50% TRAINS. THE TAIL GAS TREATING UNIT (SCOT) WILL HAVE ONE 100% TRAIN.
2. ALL THE FEED FROM THE SOUR WATER STRIPPER WILL BE FED TO ONE OF EITHER OF THE TWO TRAINS.
3. 10-K-01B IS USED AS A COMMON SPARE FOR BOTH 10-1K-01 AND 10-2K-01.
LEGEND:
STREAM NO.
FLOW, PPH
PRESSURE, PSIA
TEMPERATURE, °F
BECHTEL
BECHTEL GROUP, INC.
NEW ENGLAND ENERGY PARK
PROCESS FLOW DIAGRAM
SULFUR RECOVERY UNIT
JOB NO. 15308
DRAWING NO. 10-D-B-01
REV. A
Figure 4-12

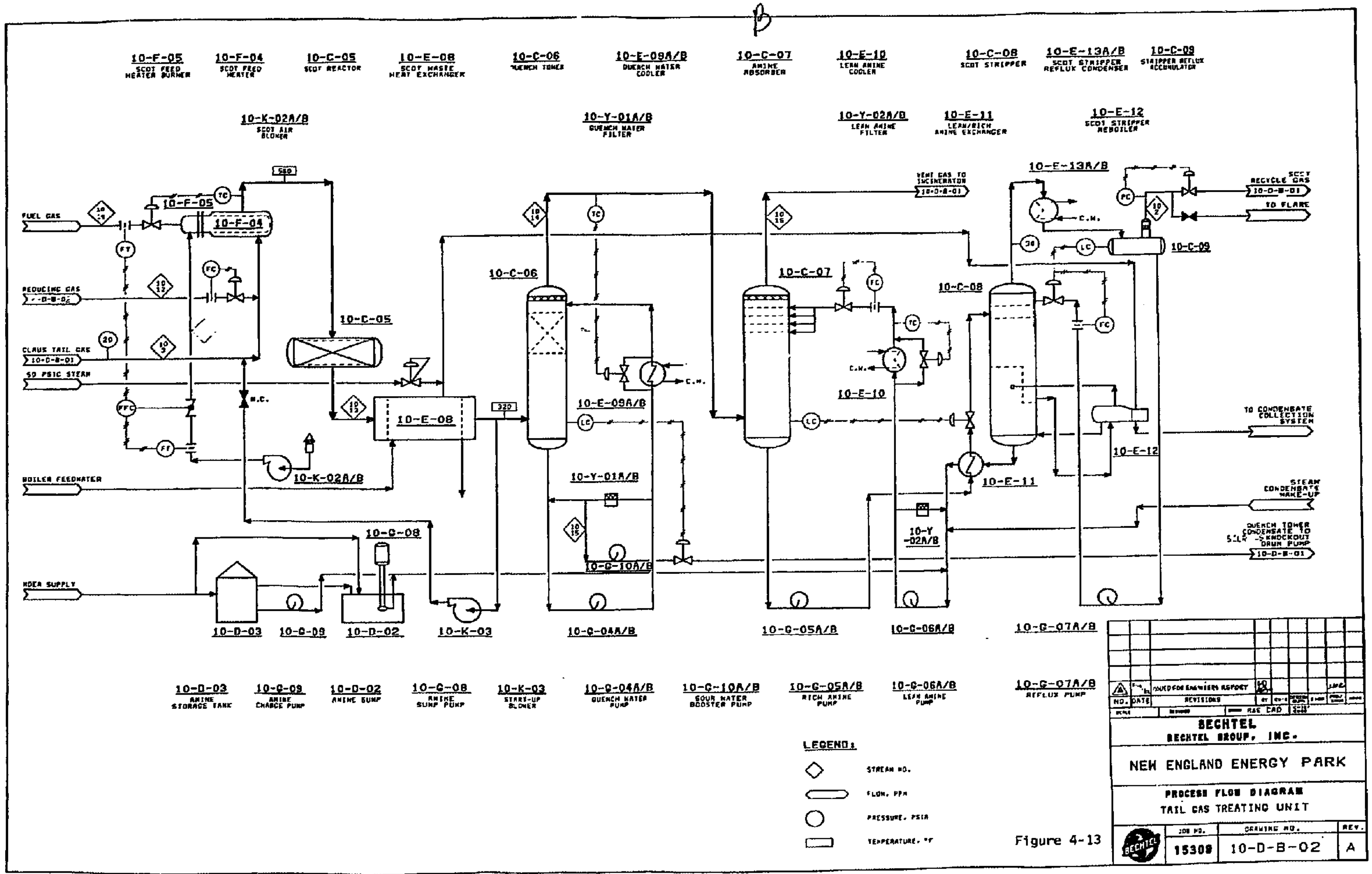


Figure 4-13

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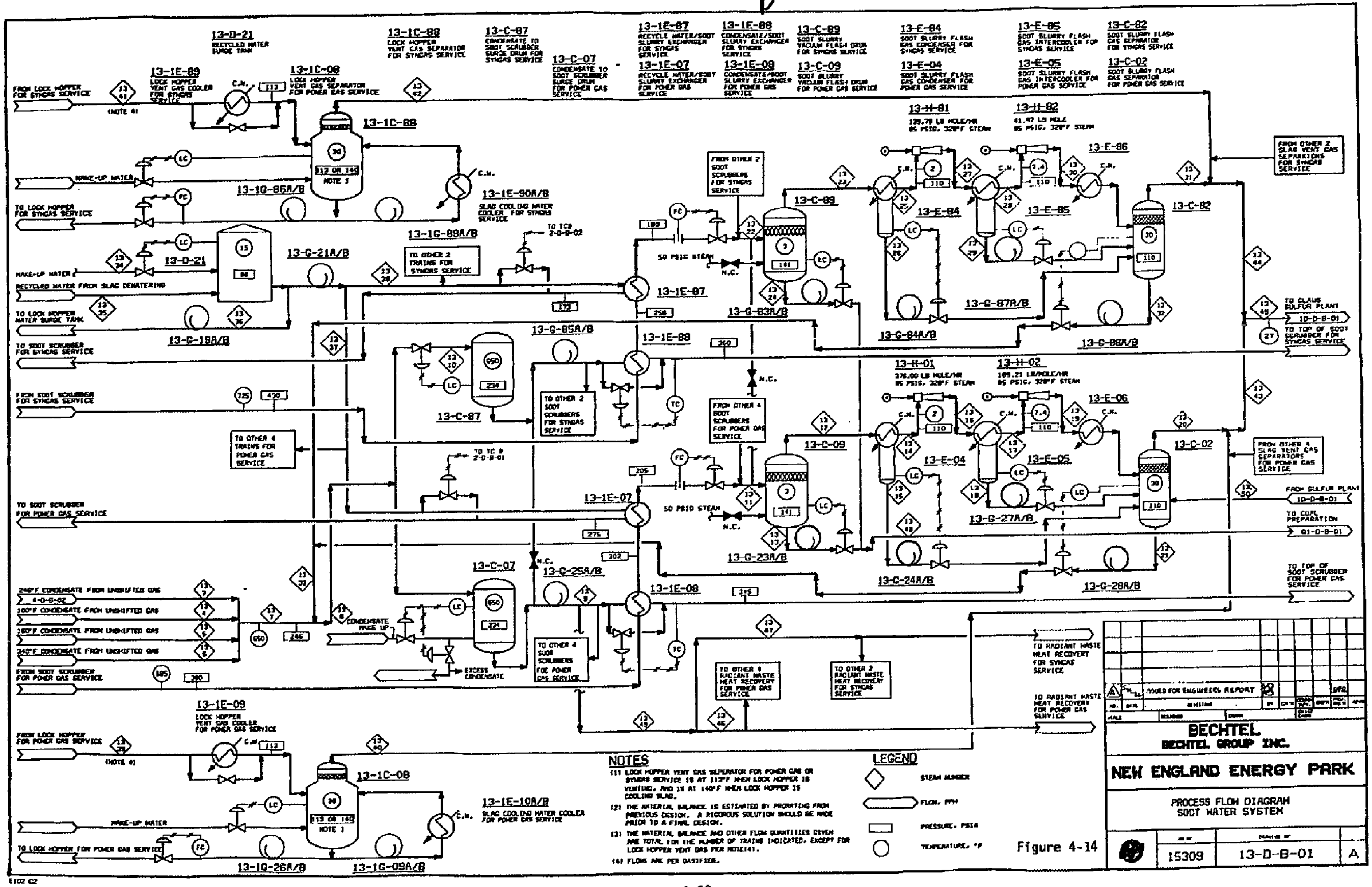

Figure 4-14

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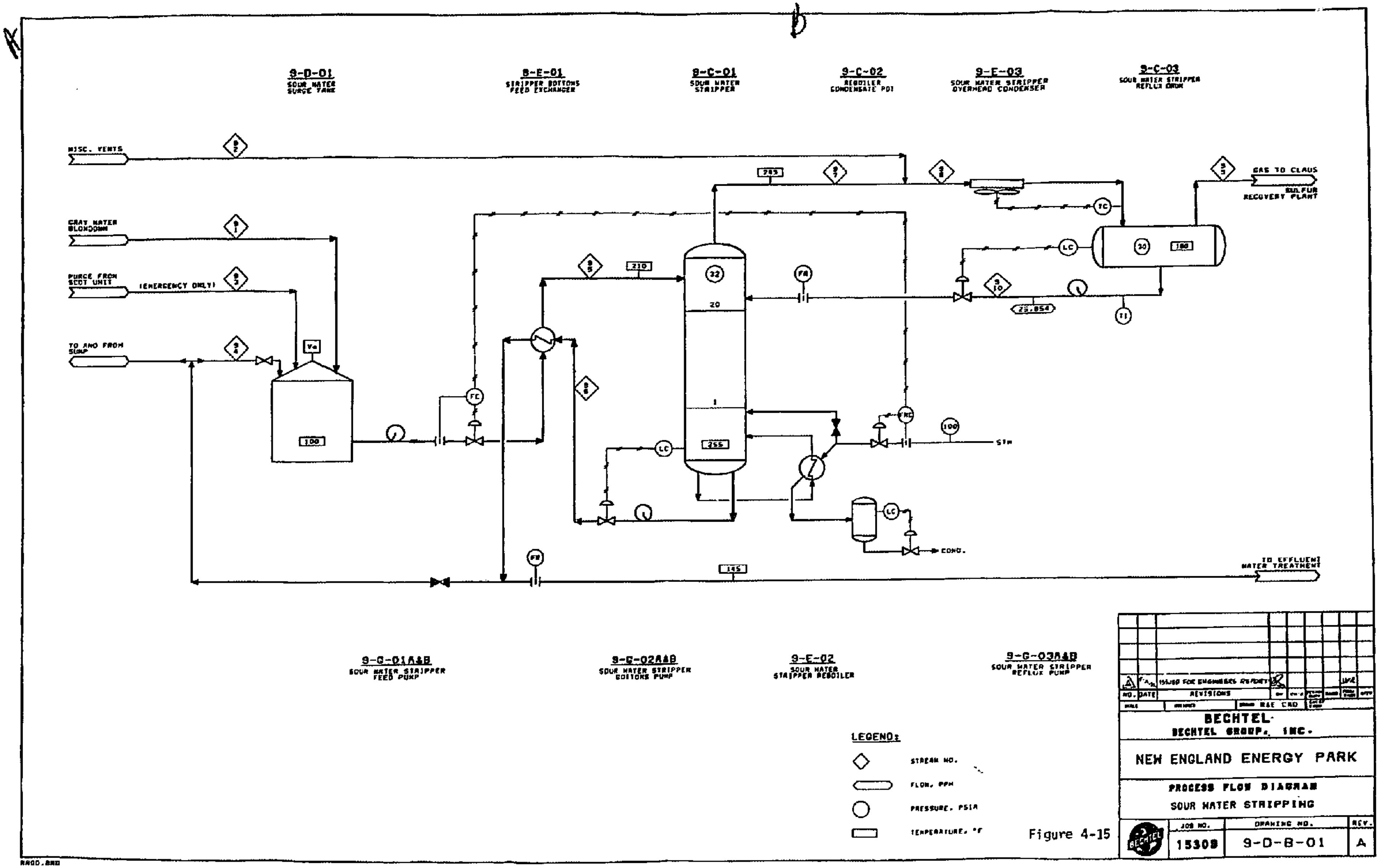

Figure 4-15

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is recovered and it is partly stripped free of dissolved noxious gases in this plant. The recovered heat is transferred to the recycled condensate and fresh feed to the gas scrubbers.

Degassing of the soot water is accomplished by flashing the cooled liquid to the lowest possible pressure. The resultant water vapors partly strip the water free of noxious gases. Additional stripping steam can be added to the bottom of the flash chamber to lower the quantities of dissolved gases in the flashed liquid. The flashed noxious gases are recompressed and sent to the sulfur recovery plant for further treatment.

Two identical vacuum-flash trains are used in the soot water treating area. One is used for degassing the soot water on syngas service and the other for degassing the soot slurry on fuel gas service. Each vacuum-flash train consists of a vacuum flash drum, a flash-gas cooler, a two-stage steam ejector (including intercooler and aftercooler) for flash-gas recompression, and a separator as shown on Figure 4-14.

The two-stage steam ejector maintains 3 psia pressure at the soot water vacuum-flash drum. Steam is used as motive fluid. Stripped soot water from each train is combined and sent to a final clarification. Flashed gases from each train are combined after compression by the steam ejectors and sent to the Claus sulfur recovery plant together with vent gases from the lockhoppers. Compressed gas pressure is about 30 psia.

If one vacuum-flash train is down, the soot slurry from this train will have to be flashed to 30 psia. Steam can

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be injected into the bottom of each vacuum-flash drum to compensate for the reduced steam formation at the higher flash pressure.

The soot water temperatures at the gas scrubbers are 430°F and 380°F for the syngas and fuel gas services, respectively. Condensate from shifted and unshifted gas cooling, and from the two vacuum ejector systems is at an average mixed temperature of 234°F. The total condensate is split into two streams for recycle to syngas and fuel gas services. Part of the condensate is sent to the water pools of the radiant waste heat recovery section to make up the water lost by evaporation, and the rest is heated by heat exchanging with soot slurry from the respective service before being fed to the top of the respective gas scrubbers. The soot water is further cooled by heating the fresh feed to the respective gas scrubber before entering the vacuum flash drum. The flashed soot water is pumped to the clarification area. The flashed vapor is cooled by a water cooler to 110°F to condense most of the water vapor and thereby reduce the load on the steam ejector. The discharge pressure from the steam ejector second stage is 31 psia.

Feed to recycled water tank is makeup water and recycled water from slag dewatering. Part of the water from the recycle water tank is sent to the lock hopper water surge tank for each gasifier. The rest is used as soot scrubbing water at each of the gas scrubbers.

Sour Water Stripping

A small percentage of the nitrogen in the coal will emanate as ammonia in the gasifier gas. Essentially, all sulfur in the coal will form hydrogen sulfide and carbonyl sulfide. All three of these components (known as sour gas) as well as other gases and soluble matter will dissolve in the water used to scrub the gas free of soot. The resultant soot water will therefore have an odor caused by the dissolved ammonia and sulfur compounds.

Much of the soot water is recycled after clarification but some soot water must be blown down to remove dissolved solids, which if allowed to build up will cause excessive scaling in the gas scrubbing equipment. The blowdown is stripped free of the sour or odorous gases prior to final treatment in the sour water stripper. Due to the simplicity and reliability of the system, only one train is included but a large feed surge tank is included for emergency periods.

The sour water stripper is a simple straightforward stripping operation. Raw feed is accumulated in the sour water surge tank for homogenization. This tank also serves to accumulate material during a forced slowdown of the stripper.

Feed material is pumped through the stripper bottoms/feed exchanger for preheating and then to the top of the sour water stripper. Preheating saves stripping steam and cools the hot effluent for subsequent treatment. The feed flow rate is controlled for optimum results in the stripper.
Ammonia, H_2S and CO_2 are stripped from the water by countercurrent steam generated in the reboiler at the bottom of the stripper. Due to their higher volatility, H_2S and CO_2 are removed first near the top of the stripper, while most of the ammonia is removed in the lower section of the stripper. The stripped gases as well as the stripping

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steam exit from the top of the stripper and into the stripper overhead condenser where most of the water is condensed and dropped into the stripper reflux drum along with the noncondensed gases (net product). The noncondensed gases and some steam are vented to the sulfur recovery plant while the condensate containing considerable dissolved gases is pumped back to the top of the stripper. There is a large recycle of gases between the top of the stripper and the reflux drum.

The stripper operating pressure is about 30 psi higher than that required to get the wet vent gases to the sulfur recovery plant. The reflux temperature is maintained at 180°F to avoid formation of solid ammonium bicarbonate and carbonate which would plug the vent lines. The line carrying the wet vent gases to the sulfur plant must be traced to avoid cooling.

Hot stripped water exits from the bottom of the stripper and is pumped through the stripper bottoms/feed exchanger prior to being sent to final waste water treating.

The bottom product will contain some residual ammonia and hydrogen sulfide but should be free of any other volatile constituent. It will also contain all other dissolved salts including nonvolatile ammonia salts. It is not practical to remove all volatile ammonia and sulfides but rather to remove enough of them to make further processing tolerable from an odor standpoint and/or to limit sulfides in the water to within environmental requirements. Also, some ammonia will be required during any subsequent biological treatments of the stripped water.

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(j) Slag Handling

The slag handling system is designed primarily to remove, dewater, screen, and store slag produced by the gasifiers. The system's secondary function is to recover minus 20 mesh particles from the slag slurry for recycle back to the coal slurry preparation plant. The system is designed to handle 1500 tpd of slag. This is based upon the study basis coal ash content and the solids introduced by the wastewater treatment system.

The gasifier lockhopper periodically discharges slag into a water filled lockhopper sump where solids settle out. A submerged drag chain conveyor at the bottom of the lockhopper sump removes collected solids and discharges them into a hopper after dewatering. There are eight drag chain conveyors, one for each gasifier. Each drag chain conveyor is provided with a variable speed drive to move the slag at the rate of 7 to 10 tons per hour continuously. A manually operated diverter gate discharges slag either onto a double deck vibrating screen or collecting conveyor bypassing screen.

Eight double deck vibrating screens rated for 10 tpd separate minus 20 mesh particles from the solids and discharge oversize material onto a 24-inch collecting conveyor. Wash water for the screens is obtained from the drag chain conveyor overflow sumps. Minus 20 mesh particles which have passed through screen with spray water are collected and stored in recycle solids storage tanks as a slurry. The stored slurry is pumped back to the coal preparation plant for recycling unreacted carbon and other solids.

A 24-inch inclined conveyor transports material from the collecting conveyor to the top of silo elevation and dis-

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charges onto a 30-inch reversible conveyor for filling of the silos. Each silo is 45 feet in diameter and 104 feet high with a 60 degree conical bottom. The two silos are sized so that they can store 4500 tons or more than 3 days (long weekend storage) of slag.

The slag is discharged into trucks for removal to on-site storage. A fleet of five (4 operating and 1 spare) 35-ton-capacity trucks will be required for a 5-day week, 8-hour daily hauling operation.

(k) Blowdown Heat Recovery

Boiler feedwater chemical treatment and water impurities result in the introduction of soluble ions, suspended solids, and sludge into boilers. As steam leaves the boiler, these impurities are concentrated in the water left behind. If this concentration is allowed to continue, the soluble components in the water will precipitate out on heat transfer surfaces and eventually even the steam will become contaminated. Ideally, impurities should be allowed to reach some limit after which the concentrated water is bled off at such a rate that the rate of impurities introduced by feedwater is equal to the bleed-off rate. This process is termed continuous blowdown.

There are several boilers in the NEEP steam system. All require continuous blowdown to control steam purity and solids buildup. Blowdown represents a loss of heat from the steam system. Rather than waste the heat, it is recovered in heat exchangers, either by condensing steam generated in a flash tank or directly in a water-to-water heat exchanger. Both methods are included in the NEEP design. The heat recovered by blowdown heat recovery is equivalent to approximately 1/2 percent of the total coal heat input. The system includes three heat exchangers and one flash tank.

(l) Site Electrical Distribution

Refer to Figure 4-16, Main Single-Line Diagram and Table 4-2 for electrical load summary.

Interconnection Interface

NEEP will be interconnected with the regional electrical utility system by means of two transmission lines via on-site 115-kV switchyard. These lines and switchyard will provide the required startup and auxiliary power and also will facilitate transmission of combined-cycle generated electric power.

Switchyard

The 115-kV switchyard will consist of six 115-kV power circuit breakers arranged in a ring bus to accommodate the termination of six power elements, as follows:

- Two transmission lines to Brayton Point Station.
- One tie-line to the combined cycle steam turbine output.
- Two tie-lines to combined cycle gas turbines output as well as station service loads (combined-cycle and gasification plants).
- One tie-line to gasification facilities station service loads.

Generally speaking, the two transmission lines and the steam turbine output line can be classified as "sources," while the two gas turbine/auxiliary power lines and the individual gasification facilities line can be classified

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as "loads." Therefore, with these elements alternated in sequence in the ring bus, the outage or failure of any single component, such as a switchyard power circuit breaker, will result in the loss of only one source element and one load element, which is a normal and reasonable operating circumstance.

It should be noted that there is in fact considerable gas turbine generation capability directly connected to two of the load elements at the 115-kV bus racks, which further enhances the site station service load reliability.

The two 115-kV bus racks, located at the combined cycle plant, are the collecting points for the gas turbine generators outputs, as well as for the combined cycle plant station service transformer connections and two of the gasification facilities auxiliary station service power supplies.

Gasification Facilities Station Service

The complete gasification complex and all related facilities (except the combined cycle plant) are electrically supplied from three 115/13.8-kV power transformers located adjacent to the oxygen plant and the switchyard.

Each transformer is supplied by one of the three separate 115-kV lines from the switchyard or bus rack. Any two of the three transformers are capable of supplying the full station service power requirements for the gasification complex. Further, any single transformer is capable of supplying approximately 75 percent of total gasification complex electrical loads.

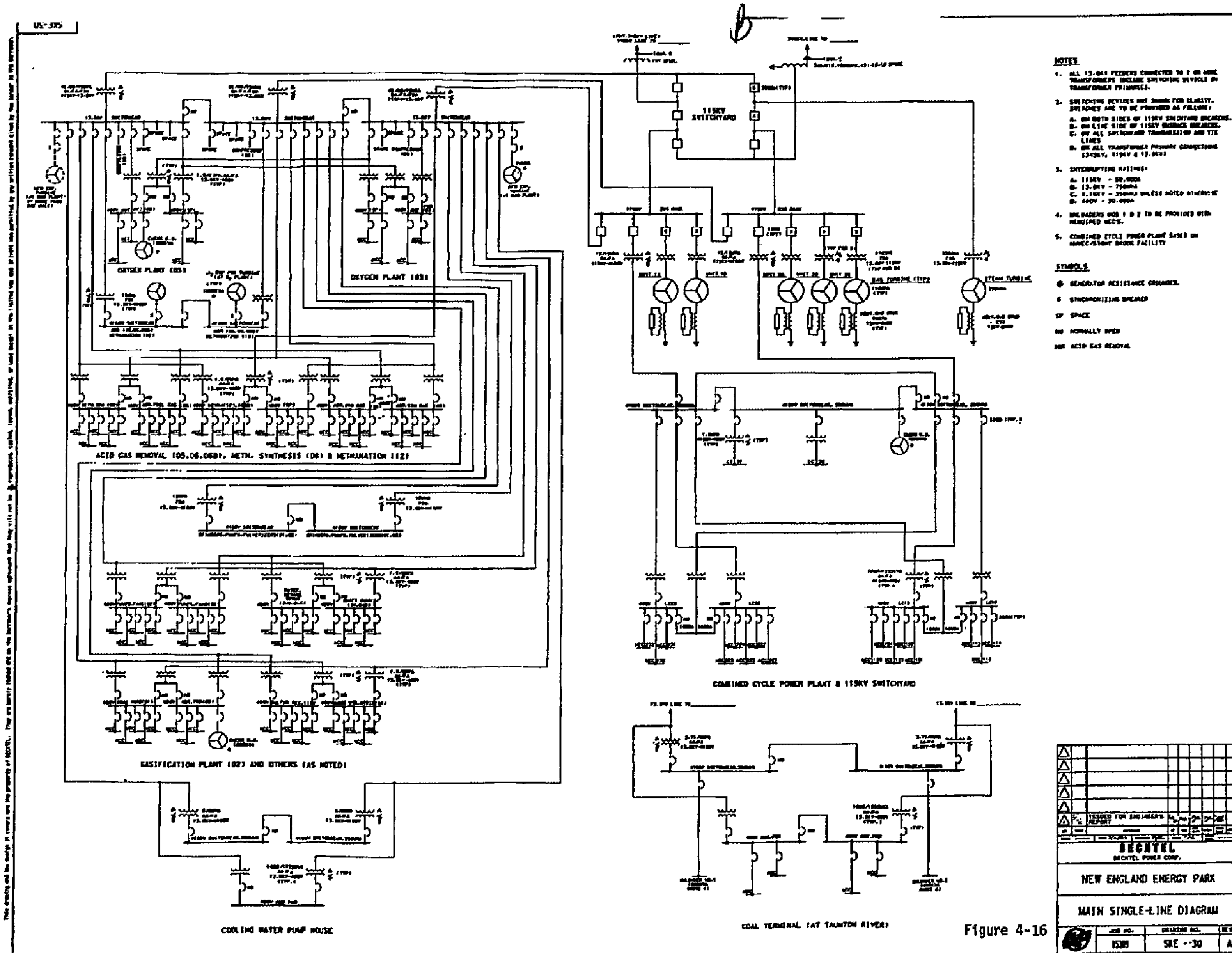
NOTES
SYMBOLS
115KV SWITCHYARD
STEAM TURBINE
GAS TURBINE (TYP)
OXYGEN PLANT (03)
ACID GAS REMOVAL (05,06,06B), METH. SYNTHESIS (08) & METHANATION (12)
GASIFICATION PLANT (02) AND OTHERS (AS NOTED)
COOLING WATER PUMP HOUSE
COMBINED CYCLE POWER PLANT & 115KV SWITCHYARD
COAL TERMINAL (AT TAUNTON RIVER)
BECHTEL
BECHTEL POWER CORP.
NEW ENGLAND ENERGY PARK
MAIN SINGLE-LINE DIAGRAM
SKE-30
A

Figure 4-16

Table 4-2

ELECTRICAL LOADS SUMMARY (PRELIMINARY)

PLANT	LOAD DESCRIPTION	VOLTAGE (V)	ELEC. LOAD (kVA)
Oxygen	Oxygen/Air Compressors	13,800	40,000
	Pumps/Aux. Power	480	3,000
Acid Gas Removal	Fuel Gas	4,160	3,500
		480	1,500
	Syngas	4,160	7,000
		480	3,000
	Methanation	4,160	11,000
		480	2,000
Methanol Synthesis	---	480	1,500
Gasification	Coal Grinders/Pulveri-zers	4,160	7,000
	Pumps	4,160	3,500
	Pumps/Fans	480	3,000
Coal Handling	Conveyors	4,160	3,000
	Conveyors, etc.	480	1,500
Water/Wastewater Treatment	Wastewater	480	700
	Sewage	480	350
	Power Plant	480	350
Shift Conversion	Fuel/Syngas	480	300
	Methanation	480	1,000
Sulfur Recovery & Tail Gas Treatment	---	480	1,500
Sour Water Stripping	---	480	200
Methanation (SNG)		4,160	3,000
		480	200
Cooling Water Pumphouse	---	4,160	8,000
	---	480	1,000
Combined Cycle Power Plant & Switchyard	---	4,160	10,000
		480	4,000
Coal Terminal (at Taunton River)	---	4,160	3,000
		480	1,000

Table 4-2 (Cont.)

ELECTRICAL LOADS SUMMARY (PRELIMINARY)

TOTAL LOADS AT NEEP SITE -	Gasification Complex (noncoincident)	103,000 kVA
	Combined Cycle Power Plant	14,000 kVA
TOTAL LOADS AT TAUNTON RIVER COAL TERMINAL		4,000 kVA
AVAILABLE SPARE CAPACITY AT NEEP SITE		15,000 kVA

Each transformer has a natural oil-air (OA) rating to meet normal loads with all transformers in service, with a forced oil-air (FOA) rating to meet normal loads with any transformer out of service, with some allowance for future system growth.

Load Grouping

In order to organize the perceived electrical loads to permit uniformity of switchgear, load center, and motor control center design, the total gasification complex electrical loads are grouped as follows:

a. Oxygen Plant
b. Acid gas removal plants, methanol synthesis, and SNG
c. Gasification plant, including:
   1) Water/wastewater treatment
   2) Shift conversion
   3) Coal handling and slurry preparation
   4) Sulfur recovery
   5) Sour water stripping
d. Cooling water pumphouse

The applicable supply voltage for the normal range of motor sizes is as follows:

480 V	-	Up to 200 hp
4,160 V	-	250 - 3000 hp
13,800 V	-	above 3000 hp

4.4.3 Plant Layout

The plant arrangement was formulated by considering the process flow, the environmental constraints, and the accumulated geotechnical data.

The following guidelines were followed in engineering the coal gasification facilities plant arrangement shown on Figure 4-17.

- Use higher grounds to facilitate site drainage and to avoid, where possible, reclamation of wetlands.
- Minimize encroachment on the Copicut Reservoir watershed.
- Drain plant water runoff away from the Copicut watershed.
- Maintain, where possible, a minimum of 100 feet from the toe of the fill slopes to the edge of wetlands.
- Locate coal and slag storage areas so that they are not visible from residential area.
- Locate cooling towers near the oxygen and combined cycle plants which represent the major heat loads and on high ground to prevent ground fogging and permit gravity flow to the process water basin.
- Locate the flare tower downwind and at least 900 feet away from the nearest occupied area.
- Locate the oxygen and combined cycle plant air compressor intakes to be fed on clean air.

Access to the site is from the west for the railroad, the main access road and the pipelines.

The facilities are oriented along the north-south axis and sequenced to follow the material process flow. The coal storage and reclaim facility is located at the north end of the plant (Plant 1A). The coal is then conveyed to the crusher building

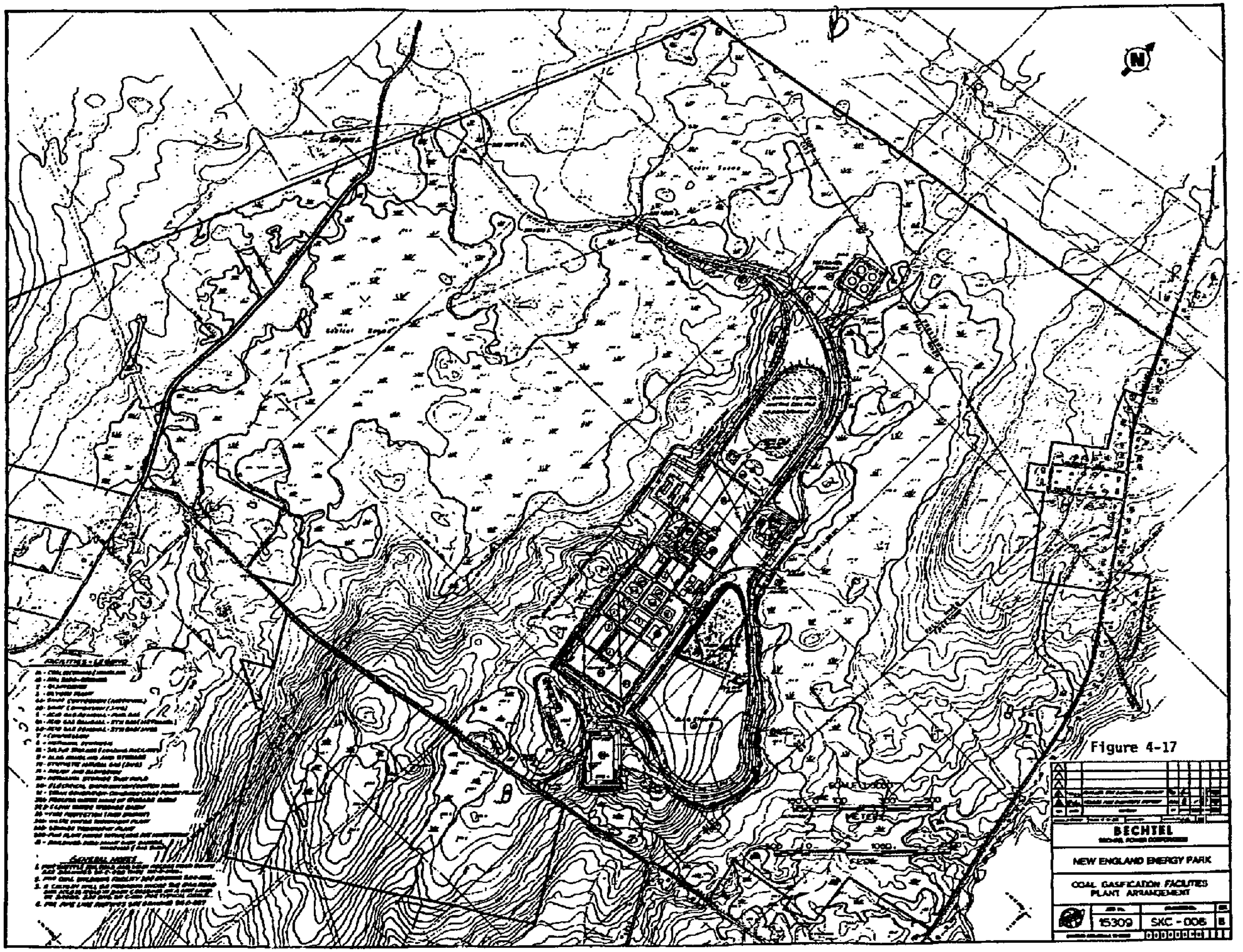
BECHTEL
NEW ENGLAND ENERGY PARK
COAL GASIFICATION FACILITIES
PLANT ARRANGEMENT
15309
SKC - 008
B

Figure 4-17

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(Plant 1B) and the slurry preparation area. Water flows to the coal slurry preparation from a branch of the plant cooling water system in the coal gasification plant (Plant 2). Coal slurry, oxygen, steam, gas, condensate, and cooling water flow to and from Plant 2 along a pipe rack which runs between the two rows of gasifiers.

Syngas flows from Plant 2 to Plants 6, 4, 7, and 8, consecutively for synthetic fuel production. Fuel gas flows from Plant 2 to Plant 5 and then to Plant 31 for electric power production. Acid gas flows from Plants 5 and 6 to Plant 10 for sulfur recovery. Cooling water flows from the storage basin (32A) throughout the plant, but primarily to Plants 3 and 31. Clean water is stored in Basin 32B and is pumped to its water treatment plant, 34C. From there it flows primarily to Plant 31 for boiler makeup. The primary source of wastewater is coal gasification. Wastewater flows from there to the treatment plant, 34A.

4.5 OFFPLOT REQUIREMENTS

4.5.1 Water Supply

The water requirements of NEEP are divided into two categories. The first category is "process" water and includes water consumed chemically in the gasifiers, water makeup for gasifier blowdown, and water makeup to the cooling towers. The second category is "clean" water and includes water required for high quality condensate makeup, potable water, plant service water, and water for fire protection. The primary process water source is the effluent of the Fall River Treatment Plant. This water is treated in a new tertiary treatment facility in Fall River and pumped to the site. The process water demand based on Kentucky No. 9 coal is approximately 18.2 MGD. It is expected that water demand will drop to less than 15 MGD when using Pittsburgh No. 8 coal.

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The primary clean water source is the Copicut Reservoir. Water from the reservoir is pumped through an existing pipeline and then pumped through a new pipeline to the site. An expected maximum of 1.2 MGD would be withdrawn from the Copicut Reservoir, with 774,000 gpd being the average quantity; this demand is relatively independent of the coal source. The Copicut Reservoir contributes to the potable water supply of Fall River. A new treatment plant is required to treat South Watuppa Pond water and transfer it to North Watuppa Pond in exchange for the City of Fall River allowing NEEP to use the Copicut Reservoir water. The Copicut Reservoir is also the backup supply of process water when the treatment plant is out-of-service. The additional demand on Copicut Reservoir would be approximately 13.7 MGD (reduced with Pittsburgh No. 8 coal); however, this situation would typically occur for only short periods of time.

(a) Process Water Supply

The source for makeup water to the process units and to the cooling towers is treated municipal wastewater from the Fall River Treatment Plant. Potential problems associated with the use of this wastewater include scaling, corrosion, foaming, and biological fouling, with the latter potentially the most severe problem. Hardness, phosphorus, ammonia-nitrogen, silica, biochemical oxygen demand (BOD), organics and suspended solids may have to be reduced to minimize the aforementioned problems and to maximize the cycles of concentrations, thereby minimizing makeup demand.

The conceptual design for the tertiary treatment of the municipal wastewater consists of a storage reservoir, two-stage lime clarification, filtration, breakpoint chlorination, a second storage reservoir, and in-line chemical treatment. The conceptual design is based on water quality

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of "typical" secondary treated municipal wastewater. Specific data for the proposed source are not available because the secondary treatment facilities at the Fall River plant only have recently started operation. The extent of in-line chemical treatment will be determined after detailed water analyses and in-field testing.

The City of Fall River has agreed to allow the use of Copicut Reservoir as a backup source of process water. A treatment facility is being provided to take water from the South Watuppa Pond. The treated water will replace water withdrawn from the Copicut Reservoir. The treatment plant will provide removal of algae and solids, disinfection, and filtration to upgrade South Watuppa water from Class B to Class A standards prior to discharge into North Watuppa.

(b) Clean Water Supply

Water will be withdrawn from the Copicut Reservoir for plant potable water, general services, and power plant boiler makeup. Copicut Reservoir water analyses indicate low total hardness, pH, and suspended solids concentrations. Chlorination and filtration will be utilized to achieve potable water quality.

After withdrawal from the reservoir, the water will pass through a chlorine contact tank to provide disinfection and some chemical oxidation. Liquid or gaseous chlorine is mixed with influent to the tank which is baffled to aid in efficient mixing and to prevent short-circuiting.

Effluent from the chlorine contact tank is pumped to the head of the carbon filters. Filtering removes organic colloids, fine suspended solids, and excess chlorine as well as taste and odor-causing constituents. The filter is backwashed about once every five days; filter backwash flows by gravity to a backwash sump. A 100 percent capacity spare filter is provided to ensure a constant supply of potable quality water to the plant.

Filtered water flows by gravity to a lined (chlorinated polyethylene, nylon reinforced, 30 mils) surge basin. Water in the surge basin, now of potable quality, is pumped to various plant water uses such as plant services, employee use, carbon filter backwash, and to the makeup demineralizer. Water for employee use is re-chlorinated in the line to provide an adequate chlorine residual; a storage tank with approximately three days potable water storage at peak flow is provided.

Dissolved constituents must be removed from the potable water before use as boiler water makeup. Demineralization is accomplished with a cation exchanger, decarbonator, and anion exchanger.

A demineralizer capacity of two 100 percent trains is provided to ensure the supply of water to the boilers. Demineralized water storage is also provided to supply water during demineralizer outages and regenerations.

4.5.2 Wastewater Treatment

(a) Process Wastewater Treatment

The process wastewater treatment plant is designed to treat approximately 9 MGD of wastewater from the Texaco gasifiers, acid gas removal, shift conversion, methanol synthesis, SNG systems, and other process-related wastewaters.

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Process wastewater quality and quantity is a function of the processes employed, coal chemistry, and process water quality. An upper limit of 1,000 ppm chloride has been recommended for the gasifiers, which is the primary factor in determining the quantity of wastewater generated. High chloride coals would result in large quantities of wastewater; high chloride water would also have the same effect but to a lesser extent since the average coal chloride feedrate is typically much greater than the water chloride feedrate. The coal used for the process wastewater conceptual plant design was Kentucky No. 9, and the primary process water was treated municipal effluent from the City of Fall River. If the Copicut Reservoir, the backup process water source, is used for process water, the amount of wastewater generated is substantially less. In addition, if the final selected coal chloride content is less than Kentucky No. 9, the process wastewater quantity will be less than the conceptual design estimate.

The process wastewater contains dissolved organics, ammonia, sulfide, formate, cyanide, thiocyanate, dissolved metals, suspended solids, and many other potential and actual constituents. Process wastewater quality is dependent primarily on coal chemistry and may vary significantly even with the same basic coal source. Complete characterization of the gasifier wastewater will require pilot plant test runs with the selected coal and process water.

The conceptual process wastewater treatment plant design is fundamentally the same scheme recommended by Texaco. It consists of chemical treatment, ammonia removal, secondary biological treatment, and chlorination.

Two separate wastewater treatment trains, each designed for 4.5 MGD, and spare equipment common to both trains, comprise the process wastewater treatment system.

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(b) Power Plant Wastewater Treatment

Wastewaters from plant service water drains and water treatment (i.e., filter backwash and neutralized demineralizer regeneration wastewaters) along with plant boiler blowdown will be collected and treated in a central treatment facility.

Wastewaters from plant service water drains will pass through oil/water separators before entering the treatment facility. Two 100 percent capacity oil/water gravity coalescing separators will be provided to remove at least 90 percent of the incoming oil producing an effluent with no more than 15 mg/l oil and grease.

A surge basin collects all wastewaters entering the treatment facility. The surge basin serves to equalize the intermittent influent flows, such as filter backwash, regeneration wastewaters, and service water drainage which may vary hourly or daily; equalization, thereby, provides a steady influent flow rate to the reactor clarifier.

Wastewater from the surge basin is pumped to three 50 percent capacity reactor clarifiers. Clarifier influent is mixed with lime to facilitate flocculation and settling of suspended solids. The clarifier will remove approximately 90 percent of the suspended solids in the influent wastewaters. Sludge produced in the clarifier will have a solids concentration of approximately 2 to 3 percent and will be sent to the gasifier plant for ultimate disposal as vitreous slag.

(c) Sewage Treatment Plant

The sewage generated at the New England Energy Park will be collected and treated in a central sewage treatment facility. The sewage treatment plant will be completed early in the construction phase to accommodate domestic wastewaters generated during construction phase. After construction, the sewage treatment plant will provide secondary treatment of the domestic waste from the NEEP facility.

The sewage treatment plant will provide secondary biological treatment and disinfection of the domestic wastewater to produce an effluent averaging 30 mg/l or less of BOD and TSS. This will be adequate treatment for effluent discharge into the Taunton River.

The sewage treatment plant is designed for a peak flow of 51,000 gpd with each treatment train designed for 17,000 gpd.

4.5.3 Coal and Slag Storage

The coal and slag storage areas are located to best satisfy plant functional requirements and environmental constraints.

(a) Coal Storage

The coal storage consists of (1) the inactive coal storage pile, (2) the active coal storage barn, and (3) the emergency coal pile stackout.

The inactive coal pile has a storage capacity of 630,000 tons for a 60-day plant requirement. The area it covers measures approximately 16 acres, and the maximum pile height is 25 feet. The soil supporting the coal will be properly compacted to receive the additional load without excessive or undesirable settlement. The coal stockpiling will be accomplished with mobil equipment prior to plant

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commercial operation. The coal will be compacted to prevent spontaneous combustion. After completion, the coal pile will be covered with topsoil and grass-seeded to prevent erosion and fugitive dust.

The coal pile will be surrounded by a drainage ditch to convey the water runoff into a collection basin. The bottom of the pile will be at least 5 feet above the high groundwater level to provide separation between the coal pile and groundwater.

The active coal storage is an open kidney-shaped pile located above grade with a continuous reinforced concrete reclaim tunnel below grade. It has a storage capacity of 31,500 tons, equal to the 3-day plant requirements.

The pile measures 360 feet in length through an arc of 120°, 150 feet in width, and 56 feet in height above finished grade. The reclaim tunnel is of reinforced concrete, supported by the basemat, and measures 22 feet in height.

A reinforced concrete underground pit will be constructed to house the 150-ton emergency reclaim hopper.

The area will be prepared and compacted to support the coal pile without undesirable ground settlement.

Water runoff in this area will be directed to the coal pile collection basin.

(b) Slag Storage

The volume of slag generated at the NEEP site is estimated at 276.5 acre-feet/year of operation. The storage area

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will be subdivided into cells each having a 3-year capacity; the ground will be prepared and compacted to receive the load imposed by the slag without excessive settlement.

The water runoff of the active cell will be collected into a settling basin and pumped to the process water storage basin. The bottom of the slag pile will be set above the high groundwater level to provide separation between the slag pile and the slag pile and groundwater.

The completed cells will be covered with topsoil and seeded over with grass.

4.5.4 Methanol Storage and Transfer

(a) Methanol Storage

Methanol is stored in tanks on site. The methanol storage tanks are located north of the main process area. Each of four tanks has a capacity of 5.7 million gallons, thus giving the plant a maximum of 30 days of methanol storage. The location of methanol storage tanks complies with National Institute for Occupational Safety and Health regulations for the storage of flammable or combustible liquids. Protection of adjoining property and water ways from accidental spillage and leakage of methanol is provided by means of lined earthen diking around the storage tanks.

(b) Methanol Transfer

A 12-inch underground pipeline conveys methanol from storage tanks to the Fall River riverfront terminal for barge loading. The pipeline is approximately 12 miles long and runs along the shuttle railroad track. The onsite pumping

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station consisting of four (3 operating and 1 standby) pumps transfers methanol at the rate of 3,000 gallons per minute. A buried surge tank of 12,000 gallon capacity is provided at the terminal site to protect the pipeline from a sudden rise in pressure caused by fast closure of a barge supply valve.

(c) Methanol Loading

A barge loading facility is provided at the coal unloading pier. Barges approximately 300 feet by 60 feet by 18 feet draft, having a 44,000-barrel capacity, are used to transport methanol. Several barges may be tied up at the pier to supplement site storage of methanol. Three trips per week of a single-barge tow would be required to meet the full plant production. The system is designed to load one barge in 12 hours. Tankers are not considered since they require ballast water, the discharge of which would pollute the Taunton River. Space to store, monitor, and treat ballast water at the terminal is not available.

4.5.5 Sulfur Storage

The Claus sulfur recovery system produces molten, elemental sulfur at a rate of 425 tons per day. This is equivalent to approximately 57,000 gallons per day. The molten sulfur is stored below grade elevation in four storage pits which together provide 4 days' storage. The sulfur is maintained between 250°F and 270°F by steam heating coils. Molten sulfur in this temperature range is similar to hot oil in its viscosity. Each pit is 28 feet square by 10 feet deep, lined with acid-resistant brick, and is covered with steel plating. The sulfur in the storage pits contains impurities, one of which is hydrogen sulfide. The hydrogen sulfide accumulates in the space above

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the molten sulfur. An eductor-operated vent system removes the gas from the pit and directs it to a catalytic hydrogen sulfide removal system. Such systems are being used in existing sulfur plants.

Normally, liquid sulfur is pumped from the storage pits through steam-traced piping into railroad tank cars. The tank cars contain steam heating coils which permit remelting of the sulfur at its destination, if required. A standard GATX molten sulfur tank car has a capacity of 13,250 gallons. Four to five cars per day are required to transport the sulfur offsite. The Essex Chemical Company, which is located on the Taunton River north of the coal terminal, has signed a letter of intent with EG&G to purchase the sulfur. Once every 24 hours, the coal unit train picks up the sulfur cars and moves them to the purchaser where they are unloaded.

If for any reason it becomes necessary to store more sulfur onsite, it will be stored in a dry form. Compressed nitrogen from the oxygen plant is used to atomize molten sulfur. The sulfur is sprayed over the top of storage bins where it solidifies into small particles before falling into the bins. The bins are protected only from the weather. No special precautions are required regarding contamination of soil or ground water because elemental sulfur is a relatively inert material. Mobile equipment can be used to move the dry sulfur back to the storage pits where it can be remelted.

4.5.6 Site Access and Development

(a) Site Access

Transportation utilizing the railroad begins at the coal unloading terminal at the former Conrail Fall River freight

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yard, then follows the right-of-way of Conrail's Newport Secondary Line northward for approximately 6 miles. At this point, the route turns east from the existing Conrail line. The proposed rail route passes under Massachusetts State Highway 24, and continues 5 miles to the plant site on new construction. The route avoids Indian property located southwest of the intersection of Copicut and Bell Rock roads. It traverses portions of the Freetown-Fall River State Forest and a wildlife management area.

The main access road begins at Interchange 37 at Massachusetts State Highway 24 and follows the existing road to a cul-de-sac. New construction will proceed easterly to join the railroad route. At this point, it parallels the railroad to the plant site.

Particular attention will be given to the drainage of both access road and railroad. Two main divisions of drainage will be considered. They are (1) surface drainage, which is concerned with runoff water from rain and melting snow, and (2) interception and control of underground water.

Drainage of surface water which falls upon the pavement is accomplished by open ditches that will collect the water prior to discharge into the natural watershed. The surface water runoff within the Copicut Reservoir watershed will be collected into a sedimentation basin. The effluent will be routed through an oil separation sump prior to discharge into the Copicut watershed.

Underground water will be intercepted by means of underdrains and distributed to the natural watershed at regular intervals as dictated by local conditions.

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(b) Site Development

The facility is located within the corporate city limits of Fall River.

The property is bounded on the north, east, and west by the EG&G, Inc., property and on the south by land owned by the City of Fall River. The north and east boundaries coincide with the Fall River Corporate City Limits.

The property is intersected by the Quanapoag Road running east-west. Particular attention was given during the site selection process to locate most of the plant facilities away from the Copicut watershed.

The site of the proposed synfuels plant is located between the towns of Fall River and Freetown in southern Massachusetts on glaciated, rolling terrain. Maximum relief in the area is approximately 100 feet, with the highlands being heavily wooded and the intervening lowlands consisting largely of swamp land, particularly near the headwaters of streams.

Drainage through the area is predominantly north to south within the NEEP site area and south to north in the vicinity of the shuttle railroad.

A literature search was performed to determine the availability of geologic publications pertinent to the proposed site. Abundant information is available relative to the Narragansett Basin, a structural geologic feature characteristic of the region. The eastern edge of this basin lies approximately 4 miles to the west of the site along the east bank of the Taunton River. Very little information was found, however, relative to the granitic rocks which underlie the site areas.

The subsurface profile of the site was investigated with 40,470 feet of geophysical survey lines and 36 borings using rotary drilling techniques. Standards Penetration Tests in the soil obtained samples of visual classification as well as standard penetration resistances; rock samples were obtained by coring. Twenty-nine trenches were excavated to permit detailed geologic mapping of overburden materials and confirm velocity measurements from the geophysical survey. The surface soils are glacially deposited dense to very dense sands and silts (till). The site is covered with a layer of topsoil nominally 0.5 to 2.0 feet thick. The bedrock in the area is a fairly uniform granite, typically slightly to moderately weathered in the top 5 feet.

For conceptual foundation design, the engineering properties of the glacial till were taken as effective angle of internal friction $\phi = 35°$ and total unit weight equal to 130 pcf. The granite bedrock was typically considered weathered in the upper 5 feet, with sound rock below 5 feet.

Preliminary allowable foundation loads were as follows:

Foundation Type	Allowable Load, TSF
Large Mat or Tank on Till	8
Large Mat on Bedrock	20
Cast-in-Place Concrete Pier, End-Bearing in Bedrock	60
4' x 4' Spread Footing Embedded 3 feet in glacial till	5

The various facilities within the plant are set above the high groundwater table at elevations ranging from 214 feet to 227 feet in order to avoid dewatering, minimize rock excavation, facilitate proper drainage, and balance the excavation and fill quantities.

Foundations for buildings and structures will be set 4 feet below finished grade for frost penetration.

The total quantity of excavation required for the plant site is approximately 3.2 million cubic yards, while the backfill required is about 3.6 million cubic yards. The balance of fill will be borrowed from the surplus excavation obtained during the construction of the railroad and access road.

During the construction phase of the facility, a plan to control sediment dispersion into the watershed will be engineered.

4.5.7 Site Drainage

Two main divisions of drainage are considered. They are (1) surface drainage of runoff water from undeveloped areas, pavement and roofs, and (2) surface drainage of runoff water from developed areas with potential for contamination by pollutants such as oil, coal dust, and chemicals.

The drainage areas and runoff flow scheme are shown on Figure 4-18.

(a) Surface Drainage of Undeveloped Areas

The design criteria for the drainage system are based on the flow generated from each runoff source by a 25-year storm. The drainage system is designed for a rainfall intensity of 2.7 inches per hour lasting 30 minutes. The

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water runoff generated by the design storm will be conveyed by open ditches and culverts to an interceptor ditch running in a northerly direction between the plant and the solid waste storage area and will be discharged on the wetland via an energy dissipater to minimize erosion. The water runoff areas being drained to the interceptor ditch are shown on Figure 4-18.

(b) Surface Drainage of Developed Area

The major runoff sources in this category are (1) the coal receiving and handling area, (2) the slag storage area, and (3) the plant equipment drainage area.

The design criteria for basins, pumps, and other treatment equipment are based on the flow generated from each runoff source by a 10-year, 24-hour storm as required by EPA Guidelines and Standards for Steam Electric Power Generation (40 CFR 423, Subpart D). For the New England Energy Park site, the governing storm has an intensity of 5 inches per 24 hours (reference: U.S. Weather Bureau, Technical Paper No. 40, "Rainfall Frequency Atlas of the United States", May, 1961).

The coal receiving and handling area includes (1) the inactive coal pile storage, (2) the active coal pile storage, (3) the mill building, and (4) the slurry preparation area.

The water runoff generated by the design storm will be conveyed by perimeter ditches to the collection basin that serves also as a settling basin to remove suspended solids from the runoff. The effluent will be pumped to the process water makeup storage basin for use in the gasification plant. Consequently, runoff discharge regulations will not

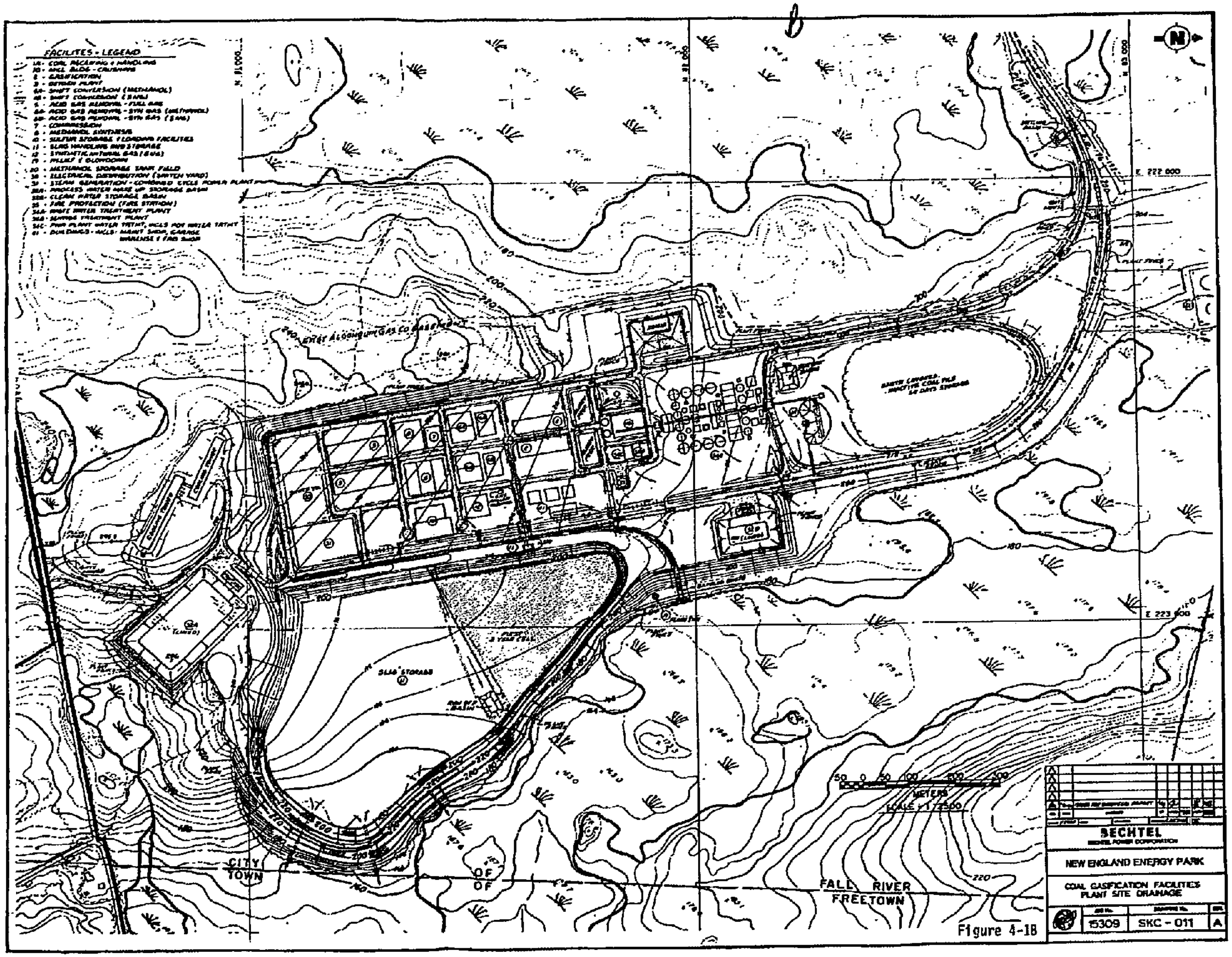
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Figure 4-1B

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apply. The computed runoff design flow is 2,450 gpd based upon a 10-year, 24 hour rainfall and the annual average runoff flow is 45 gpm.

The water runoff from the slag storage area generated by the design storm will be conveyed by the perimeter ditches of the active storage cell to the collection basin that serves also as a settling basin to remove suspended solids. The effluent will be pumped to the process water makeup storage basin for use in the gasification plant.

The plant drainage runoff will be collected by means of underground piping, catch basins, and collection tanks and will be treated in the wastewater treatment system. Although plant runoff is combined with other waste streams, the pollutant load attributable to runoff will not exceed runoff discharge limits.

4.5.8 Movement of Materials On- and Offsite

The materials being handled can be divided into two main categories: (1) solids, such as coal and dry chemicals required for plant operations, and (2) liquids and gases, such as water required for the plant operation, and products of coal gasification (methanol, SNG, and sulfur).

The movement of such materials on- and offsite is accomplished by a combination of rail and trucks and by underground pipelines.

(a) Movement of Solid Materials

The materials transported in a solid form will be railed or trucked to and from the site. The railroad, over its entire length, has at-grade crossings of two public roads:

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Copicut Road and Bell Rock Road. Both roads have light traffic volume; Copicut Road has a gravel bed while Bell Rock Road is paved. Both crossings will be equipped with automatic gates and warning lights. The impact to the traffic on those roads will be minimal. Crossing of Massachusetts State Highway 24, by the railroad, will be via an underpass while the jeep trails and paths in the State Forest area will be provided with pipe-arch underpasses.

(b) Movement of Liquid and Gaseous Materials

Liquid and gaseous materials are moved to and from the plant site by pipelines with the exception of sulfur that will be shipped by rail tankcars. The pipelines required for the plant operation include the 24-inch diameter process water pipeline that originates at the Fall River Sewage Treatment Plant and terminates at the process water storage basin, and the 24-inch diameter clean water pipeline that originates at the Copicut Reservoir Pumping Station and terminates at the clean water storage basin.

The pipelines required to move materials offsite include (1) the 12-inch diameter treated wastewater pipeline from the gasification process which originates at the wastewater treatment plant and terminates near the Fall River Sewage treatment plant and terminates near the Fall River Sewage Treatment Plant, (2) the 12-inch diameter methanol pipeline which conveys the methanol produced at the plant to the coal terminal facility in Fall River for barge loading, and (3) the 10-inch diameter SNG pipeline which conveys the SNG produced at the plant to the Algonquin pipeline.

4.5.9 Fire Protection

A fire protection system is required to mitigate the risks of fire and explosion. The system which forms the design basis for NEEP includes the following major items:

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- 2 Diesel-Driven Pumps
- 3 Motor-Driven Pumps (including jockey pump)
- 1 Foam/Dry Chemical Truck
- 1 Equipment Van
- 150 Hand-Operated Extinguishers
- 100 Hose Reels
- 70 Hose Houses
- 90 Fire Hydrants
- 100 Post Indicating Monitors
- 1 Closed Loop Underground Piping System

The system protects the following areas:

- Gasification Plants
- Oxygen Plant
- Coal Storage
- Water Treatment Buildings
- Warehouses
- Administration Buildings
- Methanol Storage Area
- SNG

In addition to the fire protection system for the process plants, fire protection systems are included for the combined cycle power plant and coal handling system.

The various plants (i.e., shift conversion, acid gas removal, methanol, sulfur recovery, etc.) are physically separated from one another to delay the spread of fire, allow for quick access to any plant by fire fighting equipment, and permit the introduction of fire fighting gear between plants for containment.

The primary source of water for fire protection is the onsite clean water storage pond which is supplied from the Copicut Reservoir.

4.6 PLANT EMISSIONS

Plant emissions are divided into four major categories: fugitive particulate emissions, gaseous emissions, liquid wastes, and solid wastes. Overall emissions and consequent waste treatment are mini-