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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 minimized through the use of the Texaco Coal Gasification Process. Because of the high operating temperature of the Texaco gasifier, by-product tars and hydrocarbons heavier than methane are not produced. Process waters are recovered and recycled to the gasification system. High-temperature operation also permits recovery of the coalash as a granular slag rather than as fly ash, thus minimizing ash disposal problems. Water treatment sludge is to be introduced to the gasifiers for capture of the sludge by the granular slag.

4.6.1 Fugitive Particulate Emissions

Fugitive particulate emissions consist of dust from coal unloading, handling, storage, and preparation. Typical control measures, such as using dust collection and wet suppression systems or enclosed conveyors, can reduce fugitive dust emissions by 85 to 98 percent, depending on the particular situation. The expected controlled emission rate of coal dust from the plant site is 525 pounds per day. An additional controlled emission of 567 pounds per day of coal dust is expected at the terminal coal handling site on the Taunton river. These emission rates are summarized in Table 4-3 and are based on a coal feed rate of 10,500 tons per day.

4.6.2 Gaseous Emissions

Gaseous emissions consist of process vent gases, incinerated tail gases, steam plant stack-gases, and power plant stack-gases. These emissions are summarized in Table 4-4.

4.6.3 Liquid Wastes

Two differing liquid waste streams are generated on site, treated, and pumped to the Taunton River. They are process wastewater and sanitary wastewater.

Table 4-3

PRELIMINARY EMISSIONS DATA
FUGITIVE PARTICULATE EMISSIONS

	EXPECTED UNCONTROLLED* EMISSION FACTOR (LB/TON)	TYPICAL CONTROL MEASURES	CONTROL* EFF. %	EXPECTED* CONTROLLED EMISSIONS LBS/DAY	TON/YEAR
COAL OPERATION**					
RIVER FRONT TERMINAL					
Vessel Unloading	0.20	Wet suppression, hopper and transfer enclosures, wind guard	85	315	52.5
Transfer, Storage, and Reclaim	0.20	Dust collection, covered and enclosed storage and transfer structures, enclosed conveyor galleries	98	42	6.9
Loadout (Train Loading)	0.40	Dust collection, wet suppression, building enclosure	95	210	35.0
PLANT SITE					
Train Unloading	0.40	Dust collection, building enclosure	97	126	21.0
Transfer, Active Storage, Reclaim, Crushing, Silo Feed Distribution	0.60	Dust collection, wetting for active storage, enclosed transfer structures, enclosed conveyor galleries	95	315	52.0
Inactive Storage	0.08	Covered with soil and seeded with grass	99	84	1.5
SLAG OPERATION					
SLAG DISPOSAL	20 (when dry)	Wetting	99.9 (for wet solids)	30	5.4

*Expected emission factors and efficiencies are based on literature data adjusted for project quantities.
**Coal Use Rate = 10,500 tons per day with a 100 percent capacity factor.

Table 4-4

PRELIMINARY EMISSIONS DATA
GASEOUS EMISSIONS*

SOURCE	CONSTITUENT	TOTAL EMISSION RATE		HGT. ABOVE GRADE		FLOW VELOCITY		VENT DIAMETER		EXIT TEMP		FLOW RATE	
		g/sec	Mlbs/day	m	ft	m/sec	ft/sec	m	ft	K	F	m^3/sec	cu ft/sec
Power Plant	N_2	976,600	186,000	61	200	15.5	50.9	5.3	17.4	410	279	1720**	60,500**
	CO_2	141,000	27,600										
	O_2	223,000	42,400										
	H_2O	76,600	14,600										
	NO_x, as NO_2	188	35.9										
	Total Sulfur, as SO_2	65	12.4	(Based on fuel gas containing 200 ppmv of sulfur)									
	CO	11.6	2.21										
	Hydrocarbons, as CH_4	3.1	0.590										
	Particulates	3.7	0.705										
Acid Gas Removal Vents	CO_2	44,700	8,520	30	98	10.0	32.8	3.2	10.5	273	32	79.3	2,800
	N_2	70,600	13,400										
	CO	106	20.2										
	H_2	3.3	0.629										
	H_2S	0.05	0.010										
	COS	2.45	0.467										
SCOT Plant Vent	CO_2	18,800	3,580	30	98	10.0	32.8	1.7	5.5	450	350	22	780
	N_2	3,860	735										
	Total Sulfur, as SO_2	8.1†	1.54										
Oxygen Plant Vent	N_2	292,000	55,600	30	98	10.0	32.8	2.7	7.3	300	81	237.6††	8,392††
Methanol Storage Tank Vents	CH_3OH	0.36	0.069	15	49	FLOATING-ROOF TANK				295	72	0.001	0.035

NOTES:

*There is no emission from the auxiliary boiler at normal plant operation. For plant abnormal operation, refer to "Sulfur Handling" Report, Section 9, dated March 1981.
**Flow rate shown is the total from 5 exhausts.
†SO_2 data are based on incineration of SCOT plant vent.
††Flow rate shown is the total from 4 exhausts.

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4.6.4 Solid Wastes

Three basic sources of solid wastes will exist during the plant operation:

a. Gasifier
b. Water/wastewater treatment systems
c. Spent catalysts

Of these three sources, slag from the gasifier, on a mass basis, comprises the major portion of the solid waste while the remaining two are minor. Furthermore, the design and integrated operating procedures for the NEEP facility presently include disposal of water/wastewater sludges (including sanitary) to the gasifier system, resulting entirely in conversion to slag. Spent catalysts will be recycled to manufacturers.

The disposal of solid wastes has assumed additional importance since passage of the Resource Conservation and Recovery Act (RCRA) and Massachusetts solid waste legislation. Of primary concern in the disposal of these wastes is protection of public health and the environment. Additional concerns are siting (avoiding flood plains, wetland, seismic areas, archeologic/historic areas, etc.) and aesthetics. The proposed engineering approach to satisfying these concerns is described below.

Based on the coal feed rate of 10,500 tons per day to the gasifier with coal characteristics as previously defined, approximately 1,500 tons per day of dry slag will be generated from the coal itself. Water and wastewater treatment sludges will contribute up to another 300 tons of dry slag per day.

Based on a density of 100 pounds per cubic foot for dry bulk slag, the total volume of solid wastes generated will be approximately 275 acre-ft per year at 90 pecent capacity.

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Based on a vertical stacking height of 40 feet, about 7 acres will be required annually for slag disposal or 210 acres over 30 years. These acreages do not include access roads, slope erosion control, runoff collection, etc.

4.7 PLANT EFFICIENCY

This section presents the overall thermal efficiencies and the distribution of energy flows for the plant. The efficiencies and energy flows are based on gasifying 10,500 tons per day of coal; thus, the total energy input to the facility is 228.3 billion Btu per day. The production of 2,500 tpd methanol consumes approximately one-third of the raw gas. The production of 50 MMSCFD SNG also consumes approximately one-third of the raw gas. After sulfur removal, the balance of the raw gas (up to a maximum of two-thirds) is used to produce electric power in a combined cycle power plant and to satisfy the internal plant fuel requirements.

4.7.1 Overall Energy Flow Distribution

The overall energy flow distribution is shown in Table 4-5. Electric power is produced throughout the year; SNG production is forecast for 6 months during the winter, while methanol production is forecast for the rest of the year. The table is based on the total coal energy input of 228.3 billion Btu per day. The power plant flows are based on burning the amount of medium Btu gas available from the process plant after supplying the internal process fuel requirements. The methanol or SNG output represents 20.7 percent of the total energy input. Energy contained in unburned carbon and ash is constant for a given gasifier feed rate. Losses from the process vents account for 0.4 percent of the total energy input.

A more detailed study of waste heat recovery has resulted in the lowering of cooling air and cooling water heat losses from

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Table 4-5

OVERALL ENERGY FLOW DISTRIBUTION
(EXPRESSED AS PERCENTAGE OF TOTAL COAL INPUT ENERGY)

ITEM	SYNTHETIC FUEL METHANOL	SYNTHETIC FUEL SNG
Methanol (HHV)	20.7	0.0
SNG (HHV)	0.0	20.7
Net Electric Power	17.9	19.8
Sulfur (HHV)	1.5	1.5
Unburned Carbon (HHV)	0.8	0.8
Slag	0.1	0.1
Process Flue Gas	0.4	0.4
Air Coolers	6.8	5.4
Process Cooling Water	20.3	20.3
Power Plant Cooling Water	7.6	9.2
Power Plant Flue Gas	11.7	11.7
NO_X Steam	1.6	1.6
Process Steam to Wastewater Stripping	7.8	7.8
Wastewater and Miscellaneous	2.8	0.7
TOTAL	100.0	100.0
PRODUCTS		
Methanol, tpd	2500	0
SNG, MM SCFD	0	50
Electric Power, MW @ 68 F	500	550

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the early case studies. Large quantities of low pressure steam are recovered in process waste heat boilers. Redesigning the gasification shift, and gas cleanup units by increasing the amount of waste heat recovery reduced the heat lost to air coolers substantially and also reduced the cooling tower load by about 14 percent, compared to early case studies.

The overall energy distribution of the plant for both methanol and SNG is shown in Table 4-5 as a percent of total coal energy input. The production rates of methanol and SNG both represent the same heating value. Electric output is lower for methanol due to the nature of the production processes. SNG production is highly exothermic and results in the generation of a significant quantity of high-pressure steam. The high-pressure steam is superheated in the combined cycle plant HRSGs and supplied to the steam turbine. Surplus low-pressure steam could be supplied from the methanol plant if fuel grade methanol were produced in lieu of chemical grade methanol. This would make up for about one-third of the electric power difference. The difference in air cooler losses represents the removal of low level heat from the methanol before it is pumped to storage. The difference in power plant cooling reflects the additional steam turbine flow required for SNG. The very large quantity of steam consumed by wastewater stripping is given in the table. The electric power generating potential of this quantity of steam represents approximately 10 percent of the total net electric power. This effect could be cut in half by the use of a better quality of water for process plant makeup (i.e., lower stripping steam flow).

4.7.2 Conversion Efficiencies

The efficiencies for converting coal to intermediate and final products are shown in Table 4-6. The estimated net electric

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Table 4-6

CONVERSION EFFICIENCIES

PROCESS	EFFICIENCY %
Coal to raw gas *	76.1
Raw gas to fuel gas **	97.6
Raw gas to syngas **	89.4
Syngas to methanol **	86.0
Fuel gas to electric power †	45.9
Coal to electric power ††	33.8
Coal to methanol **	67.4
Coal to SNG **	74.3
Coal to electric power and methanol §	38.7
Coal to electric power and SNG §§	40.3

* "Cold gas efficiency" = HHV of raw gas/HHV of coal to gasifier

** Chemical conversion efficiency

† Gross electric power production

†† Net electric power production

§ 2,500 tpd methanol production

§§ 50 MM SCFD SNG production

power, coal to busbar efficiency of NEEP is 33.8 percent. This does not include the effect of steam turbine extraction flow for wastewater ammonia stripping.

4.8 PLANT OPERATING ANALYSIS

Designs for the conceptual process and power plant presented in this report have assumed base-load operation with an overall average operating factor of 90 percent for all parts of the plant, including power generation. This section examines the plant's ability to operate at variable production rates, as well as with load balancing between power, SNG, and methanol production.

4.8.1 Variable Production Rates

Figure 4-19 shows the effect of ambient temperature on the gross and net electrical output from the plant as a whole (i.e., house loads and power recovery from fuel gas expansion is included).

The combined cycle power plant has a power output of 550 MW (net site) at 68°F while consuming two-thirds of the total gasifier raw gas production. Above 79°F, the gas turbines are incapable of consuming two-thirds of the raw gas production. At 90°F, the turbines' gas consumption capability falls to approximately 95 percent.

Below 79°F, the gas turbines are capable of consuming more than two-thirds of the raw gas. At 20°F, the gas turbines are capable of consuming 78 percent of the total raw gas production to produce 700 MW (gross).

As ambient temperature falls, air density increases. Since the gas turbine air compressor is essentially a constant volume

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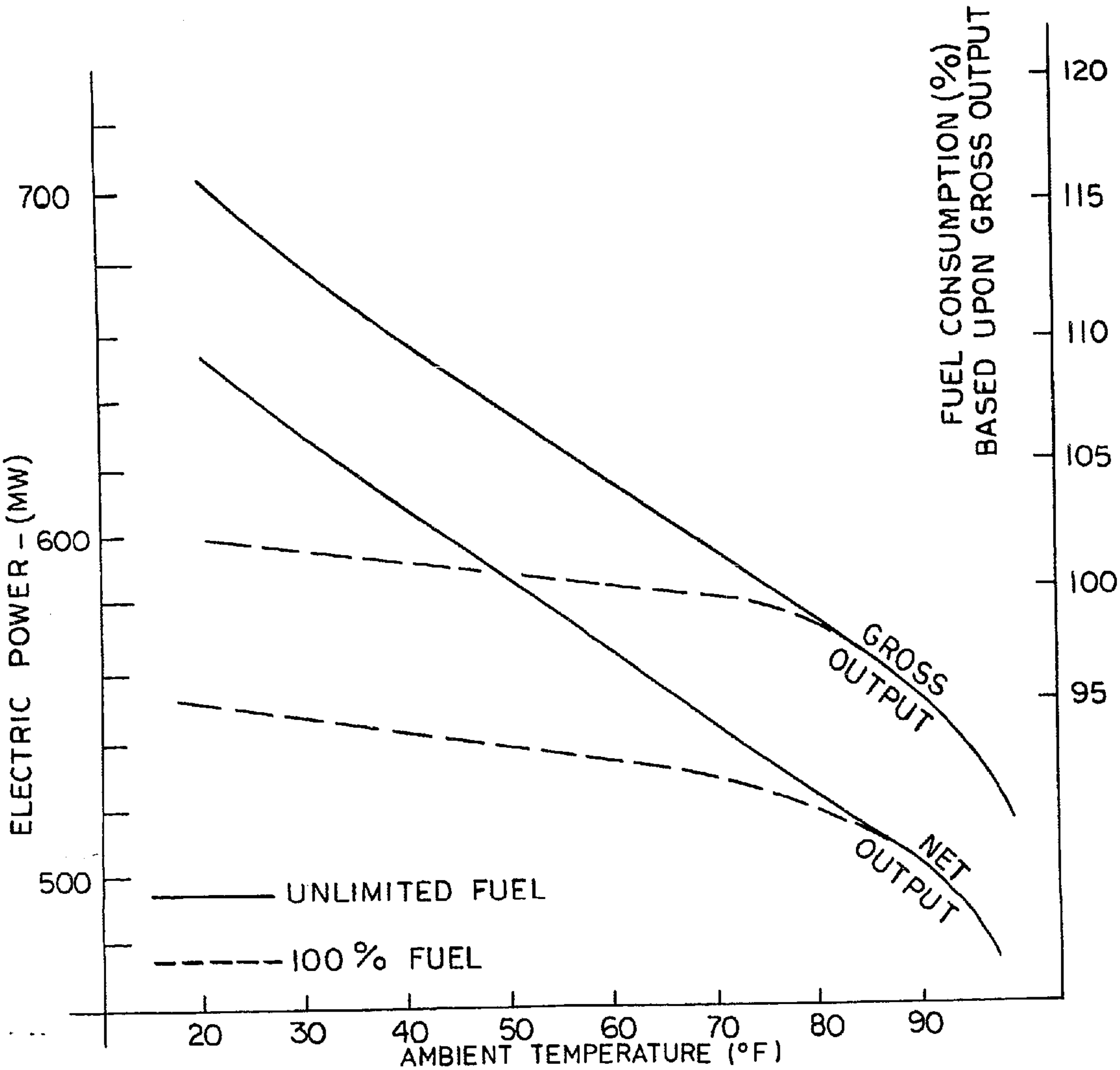

NOTE: CURVES ARE FOR SYNTHETIC NATURAL GAS CASE
FOR CHEMICAL GRADE METHANOL CASE SUBTRACT
50 MW

Figure 4-19

EFFECT OF AMBIENT TEMPERATURE ON NEEP ELECTRICAL OUTPUT machine, more air mass can be compressed with decreasing temperature. As more air is compressed, more fuel can be consumed yielding the same turbine inlet temperature. Power output increases because the mass flow rate through the turbine is higher.

Figure 4-19 shows increasing electrical power output with decreasing ambient temperature even without an increase in fuel consumption. This is due primarily to the decreasing power consumption of the oxygen plant air compressors and to a lesser extent, improving plant heat rate (i.e., efficiency) with decreasing ambient temperature.

4.8.2 Gasifier Load Leveling

Because over 75 percent of the facility's capital investment is in the coal gasification and gas cleanup equipment, it is desirable to operate the equipment at the highest possible throughput at all times. The simplest means of achieving this is to assume that the power plant is always base-loaded at rated capacity. However, in actual practice load swings will occur and have been taken into consideration by providing adequate flexibility in the design of the facility. Raw gas is diverted from downstream of the convection raw gas coolers to the syngas systems to produce more methanol and/or SNG. When methanol and SNG are produced concurrently with electrical power, each consumes one-third of raw gas production. This reduces the quantity of fuel gas for electric power production to half of its maximum quantity.

Figure 4-20 depicts the expanded methanol and SNG production versus power plant load from 50 percent to 110 percent. The maximum gasifier turndown is 60 percent for each unit. Turndown below 60 percent for each gasifier is not recommended be-

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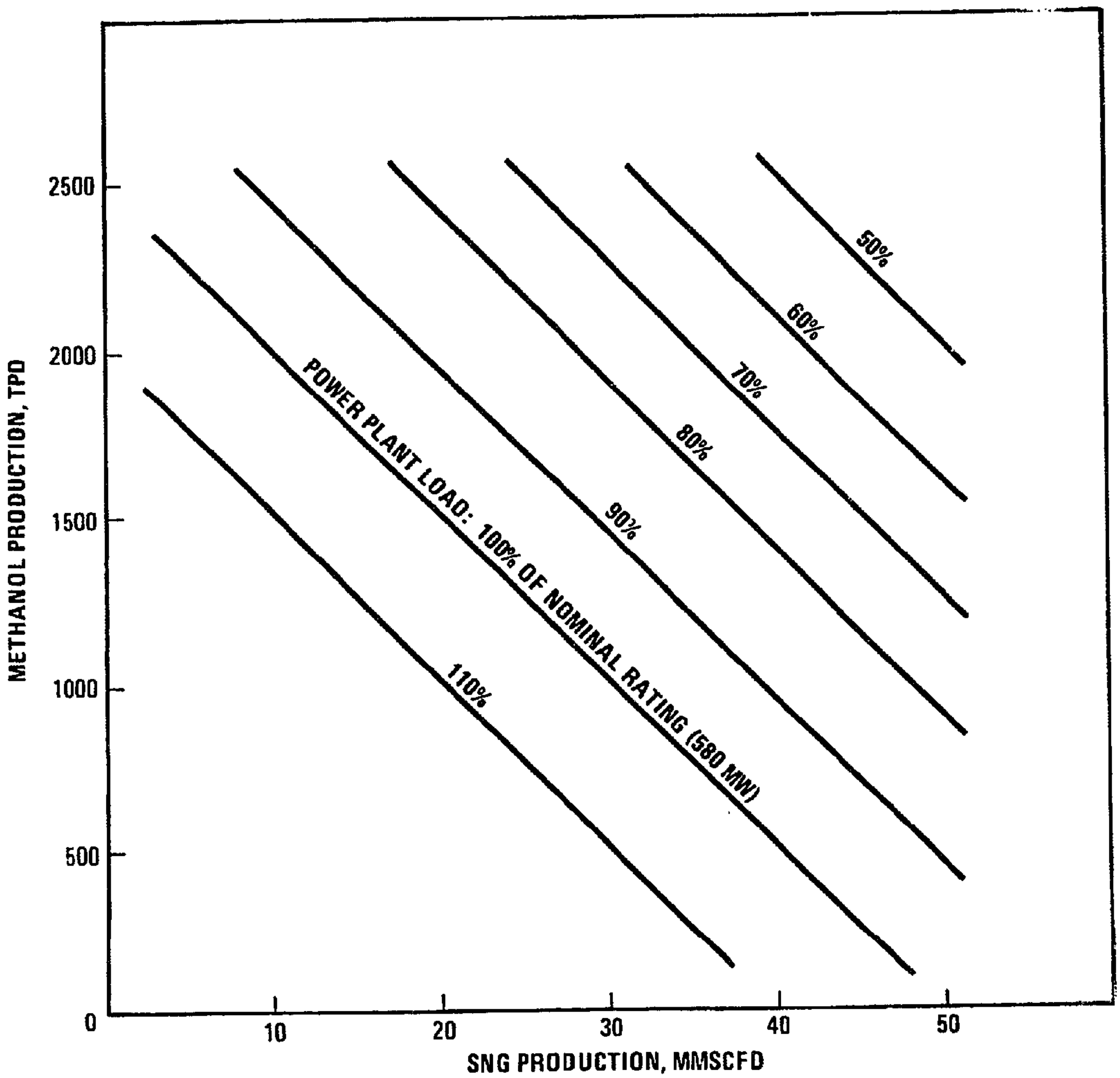

Figure 4-20
EXPANDED METHANOL/SNG PRODUCTION VERSUS POWER PRODUCTION

cause the efficiency of slurry atomization drops significantly below this level. As the power plant load decreases, more raw gas will be available from the gasifier for methanol and/or SNG production in accordance with the curves shown. It is desirable to produce maximum SNG during the winter season since the demand for heating is high. A typical winter operating mode is one wherein the SNG train produces 50 MM SCFD of SNG under fully loaded conditions and any drop in the power plant load will result in more methanol production. For example, if the power plant load is reduced to 80 percent, the excess raw gas will be channelled to the methanol train to generate approximately 900 tpd of methanol. In the summer season, forecast SNG consumption is low and peak capacity methanol production is envisaged. The methanol train is expected to operate at full capacity with the SNG train available to absorb the surplus gas when the power plant load is reduced. For example, if the power plant load is reduced to 80 percent, the SNG train will produce approximately 18 MM SCFD of methane. It is possible to operate the power plant load at 40 percent with both methanol and SNG trains operated near their full design capacity. Any reduction in power plant load beyond this level can be accomplished by reducing the number of operating gasifier modules and turning down the raw gas output.

If the power plant load exceeds 100 percent, both methanol and SNG trains can be operated at reduced capacities as shown on Figure 4-20. Operation of the power plant above 114 percent fuel consumption is not possible due to gas turbine limitations.

When the methanol or SNG facility is operated at low turndown capacity, the compressors may be operated below surge limitations. An automatic system is required to recirculate some gas to prevent surging. If both methanol and SNG are operated

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above 50 percent capacity at the time, additional injection steam at 600 psig will be required to increase the H_2O/CO ratio in the raw gas diverted from downstream of convection heat recovery for proper water shift conversion.

4.8.3 Reliability and Availability

Reliability and availability are key concerns in the design of the New England Energy Park. Considerable effort has been expended to ensure that the NEEP will exhibit superior operating performance. Reliability engineering was introduced early in the NEEP project and will continue to be emphasized throughout the life of the project. Some of the steps which have already been taken to enhance plant reliability and availability are:

- Commercially proven equipment has been used to the maximum extent possible.

- Process design philosophy has incorporated multiple train configurations to minimize the likelihood of full plant production loss.

- Spare equipment and/or excess standby capacity have been incorporated in critical areas.

- A comprehensive reliability engineering program has been instituted to provide assurance that plant performance goals will be met.

(a) NEEP Reliability Program

Reliability engineering is a methodology which relates all the factors necessary for high availability and attempts to quantify their relative importance. Also, it establishes procedures and identifies measures which will help assure achievement of the desired availability goals. The NEEP reliability program management task force is an integral part of the project engineering team. This organizational structure helps to ensure that results and recommendations of the program are incorporated into the plant design.

Before listing the individual tasks to be performed as part of the reliability program, several points must be mentioned which are necessary for the program to be successful. First, the activities of the reliability program are coordinated with the project design schedule. Efforts are being made to discover and rectify problems before they are "cast-in-concrete." Second, the NEEP will be one of the first, large-scale commercial coal gasification combined-cycle plants. It is absolutely essential that the project design team, along with the reliabilty engineers, keep abreast of the numerous Texaco process development programs being conducted both domestically and abroad.

Pilot plant testing of coal gasification is continuing to provide data on the reliability and availability of coal gasification technology. A large scale demonstration plant by Ruhrchemie/Ruhrokohle has been operated since 1978. The demonstration unit has been on line for 11,000 hours, having gasified 60,000 tons of coal. Different types of coals have been tested. Overall carbon conversion efficiency has been rated at 94 percent, which is greater than the 90 percent design basis. A full waste heat recovery train has been in successful operation for 9 months. Another demonstration unit is now operating successfully by TVA. This unit does not include radiant and convective boilers. A full scale commercial unit is now under construction by Tennessee Eastman. Still another plant has been designed

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for the Cool Water project and is currently under construction.

A particularly valuable source of information has been the developmental work being funded by the Electric Power Research Institute. In the last half of the 1970s, EPRI initiated a developmental program to prove the TCGP on a commercial, utility scale (Cool Water), and also undertook the development of an 1100-MWe integrated coal gasification combined-cycle power plant. Part of EPRI's efforts have been directed towards establishing a methodology for assessing the availability of a gasification plant, as well as compiling a component failure rate and repair data base applicable to the TCGP. In addition to the above programs, EPRI is sponsoring development of a high reliability gas turbine combined-cycle unit, with special attention being given to integration with a coal gasification plant. The data from these EPRI programs is providing to be a rich source of useful and timely information for the NEEP reliability program.

The specific tasks to be performed as part of the reliability program were selected based upon their suitability towards accomplishing particular goals related to enhancing plant safety and availability. Tasks concentrate on both a system and component level of detail. Many of the activities in the program have already been initiated.

- Establishment of Plant Performance Goals
- Allocation of Plant Availability Goals
- Preliminary Hazards Analysis (PHA)
- Availability Design Review (ADR)
- Collection of System and Component Failure Data
- Fault Hazards Analysis/Failure Modes and Effects Analysis/Criticality Analysis (FHA/FMEA/CA)

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- Critical Items List (CIL)
- System Failure Analysis
- Integrated Plant Model
- Review of Test, Maintenance, and Operating Procedures

(b) Sparing Philosophy

The reliability and availability of a full scale Texaco gasification plant using coal as a feedstock has yet to be proven on a commerical scale. For the NEEP facility to meet the overall capacity factor targets, each process plant must meet its corresponding performance goals. One of the steps taken in the design to accomplish this objective is to provide spare equipment or excess capacity at critical points in the plant. There are three basic options available when specifying sparing requirements. These options are:

- Installed Spares on Standby

  Redundant equipment is built into the plant, but does not operate during normal operation. Should one of the operating units become inoperable, the installed spare can be rapidly brought into service with minimal or no loss of production.

- Equipment Capable of Excess Production

  Most of the equipment in the plant is capable of operation at capacity levels above the stated design level. If necessary, the equipment could operate at these higher levels for short periods of time to help compensate for outages of other equipment.

- Local Warehousing of Spare Equipment

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Replacement units are kept in inventory at an on-site warehouse.

The particular sparing option, or combination of options, to be employed for each process block will depend upon several factors, such as cost, availability, and the criticality of the block to the overall facility.

(c) Risks and Mitigating Measures

This section presents the potential technical risk areas for the gasification plant and the other process facilities, their nature and risk probability, and their consequence on plant operation. The measures already taken and the recommendation(s) for further risk reduction are summarized in Table 4-7.

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Table 4-7

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Coal Grinding and Slurry Storage	Not meeting grind specification	Low	Lowers carbon conversion by about 5 to 10 percent and results in poor slurry characteristics. Would reduce plant output by an estimated 5 to 10 percent	Provided extra power and spare machinery for grinding. Provided space in the grinding area to allow the number of existing mills to double in case the rod mills must be converted to ball mills	Conduct coal grinding test for specific coal samples. Provide variable speed control on mills
	Making too low a slurry concentration due to variation of coal properties	Low	Up to 10 percent increase in oxygen and coal requirements; may increase plant power consumption by about 15 MW	Provided extra oxygen, coal, and gas handling capacity for 58 percent slurry instead of 60 percent	Conduct coal slurrying test on specific samples. Provide variable speed control on mills. Wash ash from coal to increase carbon weight percent
	Excessive rods and liner consumption due to higher hardness and lower grindability of coal	Low	Higher operating cost	None	Conduct coal grinding tests on specific coal samples; use rods and liners with higher hardness
	Piping pluggage by coal slurry due to concentrated coal slurry and lumps	Very Low	Reduces on-stream factor	Minimized dead pockets and provided an efficient flush system. Provide density measurement instrumentation	Improve slurry density control
	Toxic gas release in grinding area resulting from soot slurry recycle	Low	May force a plant shutdown. Could temporarily eliminate soot recycle until degassing operation is fixed. Would increase coal consumption by about 5 percent for period of no soot recycle	Provided soot slurry vacuum degassing	Consider eliminating soot slurry recycle. Recycle the wastewater back to the scrubber. Combine the soot with slag and dispose

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Oxygen Production	Prolonged (more than 24 hours) shutdown of any one of the oxygen plant trains because of the following reasons:				
	Failure of air compressor system	Very Low	18 percent reduction in gasification capacity resulting from the loss of one oxygen train	None	Evaluate temporary or additional permanent liquid storage
	Failure of cold box	Very Low	18 percent reduction in gasification capacity resulting from the loss of one oxygen train	None	Evaluate temporary or additional permanent liquid storage
	Failure of oxygen compression	Low	18 percent reduction in gasification capacity resulting from the loss of one oxygen train	Provided spare parts inventory	Consider use of spare oxygen compressor
	Imported power failure/ voltage reduction	Low	18 percent reduction in gasification capacity resulting from the loss of one oxygen train	Provided capability to handle 15 to 20 percent voltage dip at average conditions without shut-down. Added liquid oxygen storage, pumping, and vaporization capacity for up to 24 hours for a single train	Evaluate temporary or additional permanent liquid storage
	Cooling water failure	Very Low	Loss of oxygen trains. Plant shutdown after 8 hours	Separate cooling tower provided for the oxygen plant with its own sparing. This would also prevent contamination of cooling water from process fluids leakage	Provide a manifolding system such that the second cooling tower can be used for the oxygen plant service on a temporary basis
	Steam failure	Very Low	Loss of three oxygen trains. Plant shutdown after about 12 hours of failure	None	None

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Oxygen Production (Continued)	Heavy contamination of ambient air by CO_2, sulfur compounds, and coal dust	Low	H_2S would have a corrosive effect on the heat exchangers causing increased maintenance. CO_2 levels that are three to four times the design level can be handled for short periods (hours). Longer periods will result in O_2 plant shutdown	Provided high CO_2 vent stack and flue gas reheat system for better dispersion of CO_2 and sulfur compounds in the air. Coal dust will be handled by the O_2 plant filters. Coal-handling areas have been located to minimize exposure of the O_2 plant inlets to coal dust. Air intakes are located on plant windward.	Make a detailed gas dispersion analysis based on specific site and given plot plant
Slurry Pumping	Creation of coal lumps and subsequent pump failure resulting from poor slurry control	Low	Reduces on-stream factor. Could result in gasifier(s) shutdown	Provided flush system, Screens at output of mills, spare pump	Provide slurry concentration controllers
	Very high rate of erosion	Low	The rate of erosion may increase by a factor of two; this may result in an increase in the maintenance costs and may reduce the overall on-stream factor by about 1 to 2 percent	Used diaphragm pumps and spare pumps	Change to harder alloys. Evaluate basalt-lined pump casings
	Excessive wear on the impeller of the centrifugal pumps	Moderate	Higher maintenance cost. The effect on onstream factor is negligible	Used open impeller pumps	Consider use of advancing cavity pumps
Slurry Preheating	Coal lumps in heat exchanger due to too heavy slurry and poor slurry flow distribution	Indeterminate	Heat exchanger will come out of service due to pluggage by coal lumps. This increases coal and oxygen consumption each by about 2 percent, respectively, but will reduce 50 psig steam consumption. Would increase CO_2 production by about 3 percent	Design of exchangers is by vendors experienced with coal slurry heaters; provided density measurement instrumentation and system bypass piping	Develop more uniform slurry concentrations including use of additives
	High fouling in the slurry preheater due to coal minerals	Indeterminate	Reduces slurry temperature and increases oxygen and coal consumption each by about 2 percent	Used conservative heat transfer coefficient. Design is by experienced vendors	Run tests on slurry rheology and heat exchange characteristics

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Gasification	Refractory failure resulting from excessive temperature due to inaccurate measurement, and due to leaching and/or thermal shock	Very Low	High refractory consumption; premature gasifier shutdown. If refractory life is reduced from 1 year to 6 months, the maintenance cost will increase and the on-stream factor may be reduced by about 5 to 10 percent	Two different types of temperature measurement plus downstream gas analysis were provided; installed high-quality bricks with good resistance to slag and thermal shock in gasifiers. One spare gasifier provided	Acquire know-how on a confidential basis from Ruhrchemie, Texaco, and others, for selection and protection of temperature measurement devices. Run brick resistance tests with molten slag
	Poor temperature measurement in the gasifier	Indeterminate	Very high or very low gasifier temperature; this may result in either excessive gasifier temperature or ash solidification, respectively, and ultimate gasifier shutdown (see the risk for refractory failure above)	All reasonable measures were included in the estimate. This includes very precise oxygen flow control	Acquire know-how on a confidential basis from Ruhrchemie, Texaco, and others
	Premature burner failure	Indeterminate	Gasifier shutdown; minor effect on on-stream factor. Downtime to replace burner about 4 hours	Used erosion-resistant alloys and redundant water cooling system. Provided spare burners	Acquire up-to-date know-how on a confidential basis from Ruhrchemie, Texaco, and others. Follow electric utility CWM developments
	Gasifier burner pluggage due to coal lumps	Low	Gasifier shutdown. Minor effect on onstream time if lumps are not distributed throughout slurry system	None	Acquire know-how on a confidential basis from Ruhrchemie, Texaco, and others
Radiant Waste Heat Boiler	Slag deposits on tubes resulting in poor heat transfer	Low	Gasifier shutdown; reduced on-stream factor by about 1 to 2 percent	Sootblowing provided; one spare gasifier train	Acquire confidential know-how from Ruhrchemie and Deutsche Babcock based on their operating experience; eliminate waste heat boiler
	Slag accumulation in the bottom section resulting from unpredictable slag characteristics	Very Low	Gasifier shutdown; decreased on-stream factor	Water circulation through bottom section was provided. One spare gasifier train	Acquire confidential know-how from Ruhrchemie and Deutsche Babcock based on their operating experience

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBA-BILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Radiant Waste Heat Boiler (Continued)	Unpredictable problems resulting from scale-up of the waste heat boiler	Low	Gasifier shutdown; decreased onstream factor	Used experienced vendor who has knowledge of in-plant operating experience with demonstration scale unit	Consider replacing radiant boiler with direct quench; acquire information from full-scale facilities of others
	Corrosion of tubes due to presence of H_2S and Cl	Low	Reduces tube life; increase maintenance cost	Tube deterioration by corrosion has been considered in the maintenance costs on the basis of the predicted tube life	Use tubes with higher chrome content. Use thicker tube wall. Consider washing of sulfur-bearing compounds and chlorides from the coal
	CO_2 corrosion on wet parts of the radiant boiler	Low	Reduces vessel life; increases maintenance costs	Provided ammonia injection capability for pH control	Verify by test the amount of ammonia formation in the gasifier section
	Erosion of tubes by slag and dust	Low	Reduces tube life; increases maintenance cost	Necessary precautions are provided in the mechanical design	Acquire knowledge from Ruhrchemie
	Higher exit temperature from the radiant boiler resulting from poor heat transfer	Low	May cause slag deposits in the convective boiler, eventual gasifier shutdown, and increased maintenance costs	Provided sootblowing capability in the radiant boiler to maintain adequate heat transfer	Develop adequate sootblowing cycles
Convective Waste Heat Boiler	Soot accumulation in the lower section of the convective boiler due to mechanical problems in soot-blowing system, soot removal system, etc.	Low	Pluggage of the boiler and eventual shutdown of the associated gasifier; increased maintenance costs	Necessary precautions for preventing this problem were covered in cost estimate	Consider replacing convective boiler with direct quench; get operating know-how from Ruhrchemie and Deutsche Babcock
	H_2S and Cl corrosion on tubes	Low	Reduces tube life; increases maintenance costs	Tube replacement has been considered in the maintenance costs based on the predicted tube life	Consider replacing convective boiler with direct quench; use tubes with higher chromium content; use thicker tube wall

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Convective Waste Heat Boiler (Continued)	Erosion of tubes by slag and dust	Low	Reduces tube life; increases maintenance cost	Necessary precautions are considered in the mechanical design	Acquire knowledge from Ruhrchemie
	Scale-up	Low	Reduced steam production and related impact on oxygen production	Used experienced vendor	Consider replacing the convection boiler by direct quench; acquire information from full-scale facilities
Economizer	CO_2 corrosion	Low	Need to bypass the economizer which will result in production of less high-pressure steam (about 2,000 lb/hr per economizer) and more low-pressure steam (about 2,000 lb/hr per economizer)	Provided preheat for BFW above syngas dew point temperature. Bypass piping provided	Determine benefits/requirements of NH_3 addition
	Economizer pluggage	Moderate	Higher pressure drop across the economizer. Need to bypass the economizer which will result in production of less high-pressure steam by about 12 percent per train (where economizers are employed) and more low-pressure steam by about the same amount	Estimate includes necessary preventive measures. Bypass piping provided.	Rely on other project experience
Soot Scrubber	Soot and entrained moisture carry over from the soot scrubber due to upset process conditions	Low	See the first risk for shift catalyst	See the first risk for shift catalyst	See the first risk for shift catalyst
	CO_2 corrosion	Low	Reduces on-stream factor and increases maintenance cost	Provided ammonia injection capability	Run pilot test to verify the pH of the liquor in the scrubber
	Chloride corrosion	Low	Reduces on-stream factor and increases maintenance cost	Provided large amount of blowdown from the gasifier to water treatment	Run specific test with high chloride content coal. Evaluate washing of chlorides from coal
	Formic acid corrosion	Low	Reduces on-stream factor and increases maintenance cost	Provided ammonia injection capability	Determine formic acid production in a pilot plant

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Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Slag Letdown Valves	Excessive valve erosion	Low	Higher maintenance requirement. Lower onstream factor	Used conservative design. Provided an inventory of spare valves	Get operational experience from Ruhrchemie and Texaco
Slag Lockhopper	Erosion, corrosion, and pluggage due to unknown characteristics of the slag and presence of dissolved acid gases	Low	Increases maintenance requirements; causes difficulties in operation (requires more operator attention and, probably, more manual control)	Experience and design changes from operating plants incorporated	Get operational know-how from Ruhrchemie, Deutsche Babcock, Texaco, and others
Shift Catalyst	Catalyst pluggage by soot, and catalyst destruction by entrained moisture, due to upset conditions in the soot scrubber	Low	Plugs the shift catalyst resulting in reduced catalyst activity. Reduces CO conversion from 95 to 90 percent, increases catalyst consumption, and increases the pressure drop in the reactor	Provided conservative multistage scot scrubber design; preheated the feed gas to 90 F above its dew point	Acquire know-how from Ruhrchemie, for soot scrubber operation
	Runaway condition in the first reactor to a temperature above catalyst tolerance due to high CO/H_2 ratio and remote probability for methane formation	Very Low	Reduces catalyst life and results in ultimate shift reactor shutdown	Added extra catalyst volume in the first bed. Designed for maximum theoretical runaway condition of the shift reaction	Consider shifted gas recycle to the first stage shift reactor. Consider reactor with refractory lining
	Liquid water carryover to the the catalyst due to upset conditions in the soot scrubber	Low	Catalyst destruction and high-pressure drop	Provided efficient vapor/liquid separation. Preheated the feed gas to over 500 F	Develop proper plant operation and control procedures
Shift Reactors and Heat Recovery System	H_2S corrosion	Very Low	Higher maintenance requirements; frequent shutdowns of the shift section; reduction in on-stream factor	Used stainless steel cladding in the first bed	Evaluate lining reactors with refractory
	Chloride corrosion	Very Low	Higher maintenance requirements; frequent shutdowns of the shift section; reduction in on-stream factor	Used carbon steel heat exchangers in the wet zones	Develop a water flush system

Table 4-7 (Cont.)

SUMMARY OF TECHNICAL RISKS AND MITIGATING MEASURES

RISK AREAS	NATURE OF RISK	PROBABILITY	CONSEQUENCE ON THE OPERATION	MEASURES ALREADY TAKEN	PROGRAM FOR FURTHER RISK REDUCTION
Shift Reactors and Heat Recovery System (Continued)	CO_2 corrosion in the wet zones of the gas-cooling heat exchangers	Low	High corrosion rate where wet gas is condensed. High maintenance; reduction in on-stream factor	Provided NH_3 injection capability	Consider different alloys resistant to CO_2 corrosion. Consider bleeding off cold condensate at 110 F to avoid potential problems of forming ammonium carbamate
Sulfur Plant	Air blower failure	Very Low	Slightly reduces the onstream factor in sulfur plant	Provided one common spare with extra capacity for high sulfur feed	None
	Ammonia reaction with SO_2, and pluggage of the catalyst in the Claus Plant	Very Low	Lowers H_2S conversion to sulfur and increases pressure drop	Provided for precombustion of sour water stripper overhead	None
	Sulfur solidification in transfer lines	Low	Excessive solidification may lead to sulfur plant shutdown. Outage is expected to be a few days	Provided steam tracing	None
Tail Gas Incineration	Incomplete combustion of H_2S caused by low temperature and deficiency of oxygen	Very Low	May cause H_2S leakage into the SCOT system and subsequently to the atmosphere	Incinerate at 1500 F using 40 percent excess air	Increase incineration temperature
	Sulfur-plugging of transfer line from the Claus plant to the incinerator	Very Low	Increases pressure drop in the transfer line and creates operational problems	Provided steam tracing	Evaluate use of demister in sulfur plant
	Sulfur plant tail gas leakage into the atmosphere due to positive pressure	Low	Creates environmental and safety problems	Installed induced draft fan downstream of the incinerator	None
Soot Slurry Degassing (Sour Water Treatment)	Residual H_2S and HCN which may become a safety hazard in the grinding area	Very Low	May cause H_2S release in coal preparation area and need to stop soot recycle	Provided vacuum degassing for the soot slurry liquor	Eliminate soot recycle

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5. MARKETING

5.1 INTRODUCTION

The marketing plan for New England Energy Park products is based on a multi-product production strategy. The major product, electrical power, serves as the anchor for the project, since electrical power is traditionally marketed under long-term contracts. Contractual terms are being sought under the provisions of the Public Utility Regulatory Policy Act of 1978 (PURPA) which will allow project sponsors a return on equity commensurate with the risk of a pioneer project while offering utility rate payers a long-term savings over the oil-generated power it displaces. This marketing objective is feasible in the New England Power Pool (NEPOOL) because of the Pool's heavy dependency on oil-fired generation through the 1990's. Extensive analysis has been performed on NEPOOL's generation situation and future options open to the pool. The New England Energy Park unit presents an attractive option to the Pool on an economic, environmental and financial basis, as shown in the following section on market analysis. Discussions are in progress with several utilities regarding power purchase, operation of the facility and possible ownership of the capacity. Placement of a large cogenerator on the NEPOOL system presents first-of-a-kind legal, regulatory, and institutional issues which require resolution by the utilities as a group. The NEEP sponsors are working toward resolution of these issues in cooperation with the New England utilities.

Methanol marketing has been based on a bootstrapping approach with sales to the turbine market in the early years allowing a least cost market position in the transportation market, when that market develops. The nearby New York/New Jersey area presents a large utility turbine market. Four utilities represent a large enough market for the offtake. Discussions have also been initiated with Mobil Oil Corporation regarding the feasibility of piping methanol to the Massachusetts Municipal Wholesale Electric Company (MMWEC) combined

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cycle unit in Ludlow, Massashusetts. In addition, Brooklyn Union Gas Company is considering the feasibility of methanol as a feedstock for their SNG plant at Green Point, New York.

Natural gas (methane) market analysis was not begun until the entry of Brooklyn Union Gas Company and Eastern Gas and Fuel Associates into the project. At that time, natural gas supply and demand balances were examined for the northeastern region of the United States. Methane demand has a seasonal component throughout the U.S.; however, the availability of methane supplies during the winter heating season is particularly important in the northeastern region because of the severity of the climate. The northeastern utilities deliver 5 to 7 times as much gas in the winter as in the summer. With limited gas storage available, the inherent flexibility of NEEP in controlling the quantity and timing of methane delivery is of great value to the northeast.

5.2 MARKETING OBJECTIVES

- Long-term contracts are being sought for power and methane. These contracts shall contain pricing provisions tied to reasonable alternatives for the consuming sector; they shall also contain requirements that the products must be taken if available.

- Methanol shall be sold on a commodity basis into the New York/New Jersey stationary turbine market. Because minor capital investments will be necessary for turbine modifications, short term contractual arrangements for methanol are likely during the early period of facility life.

- The product contracts ensure that NEEP products are placed prior to startup and that partial credit support is provided.

- The proposed marketing arrangements shall protect the nonregulated status of the New England Energy Park. Although methane and power are sold into regulated markets, contractual arrangements are being designed to insulate non-utility sponsors from regulation under the Public Utility Holding Company Act or rate regulation by the Federal Energy Regulatory Commission or the Massachusetts Department of Public Utilities.

- Contract provisions for the placement of baseload power and the placement of full production of methane in the winter months and methanol in the summer months are being sought. Operational considerations, particularly reliability, indicate that the IGCC train is best run in a baseload condition. The SNG and methanol downstream units are capable of absorbing operational swings.

5.3 MARKETING PROGRAM

5.3.1 Electric Power

The power from the New England Energy Park is being marketed into the most integrated pool in the United States. NEPOOL is a cooperative arrangement among New England utilities that has been evolving over a substantial period of time. In 1954, the Yankee Atomic Electric Company was formed by ten New England electric utilities to construct a 175-megawatt nuclear plant, which went into operation in 1960 at Rowe, Massachusetts. Following the success of this project, similar joint ventures have been formed by more than a dozen New England utilities to construct three additional nuclear power plants - Connecticut Yankee, Maine Yankee, and Vermont Yankee.

In late 1966, initial steps were undertaken to develop a power pooling agreement and a central dispatch operation, the New England Power Exchange (NEPEX). The agreement was drafted during 1967 and revised in 1968 by the NEPOOL Working Committee, which included representatives of small investor-owned systems, publicly owned systems, and the nine originators of the concept.

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Some of the current Pool members are:

- Boston Edison Company
- Central Maine Power Company
- Central Vermont Public Service Corporation
- Eastern Utilities Associates
- New England Electric System
- New England Gas & Electric Association
- Northeast Utilities
- Public Service Company of New Hampshire
- United Illuminating Company

NEPOOL currently serves four major roles:

- Long range planning
- Implementation of members' plans
- Centralized operations planning and control
- Pricing and billing procedures for exchange transactions

Dispatch is accomplished centrally under the principle of leas cost generation, and members reimburse each other through "savings share" arrangement. Centralized dispatch and plannin have led to joint investments in projects for new generation.

During the last decade the New England utilities built to mee peak load growth, which was quite brisk until the rapid run u in oil prices in 1973-1974; Figure 5-1 shows peak load growt from 1955 - 1979. The Pool is still winter peaking, but sev eral southern New England utilities have become summer peakir during the recent past. The NEPOOL peak load growth projectic is 2.6% percent annually, but individual utilities are project ing lower growth. For example, Boston Edison foresees a loa growth rate of 1.7% if coal conversion programs are successfu and the price of power is held down, but only 1% if their oi

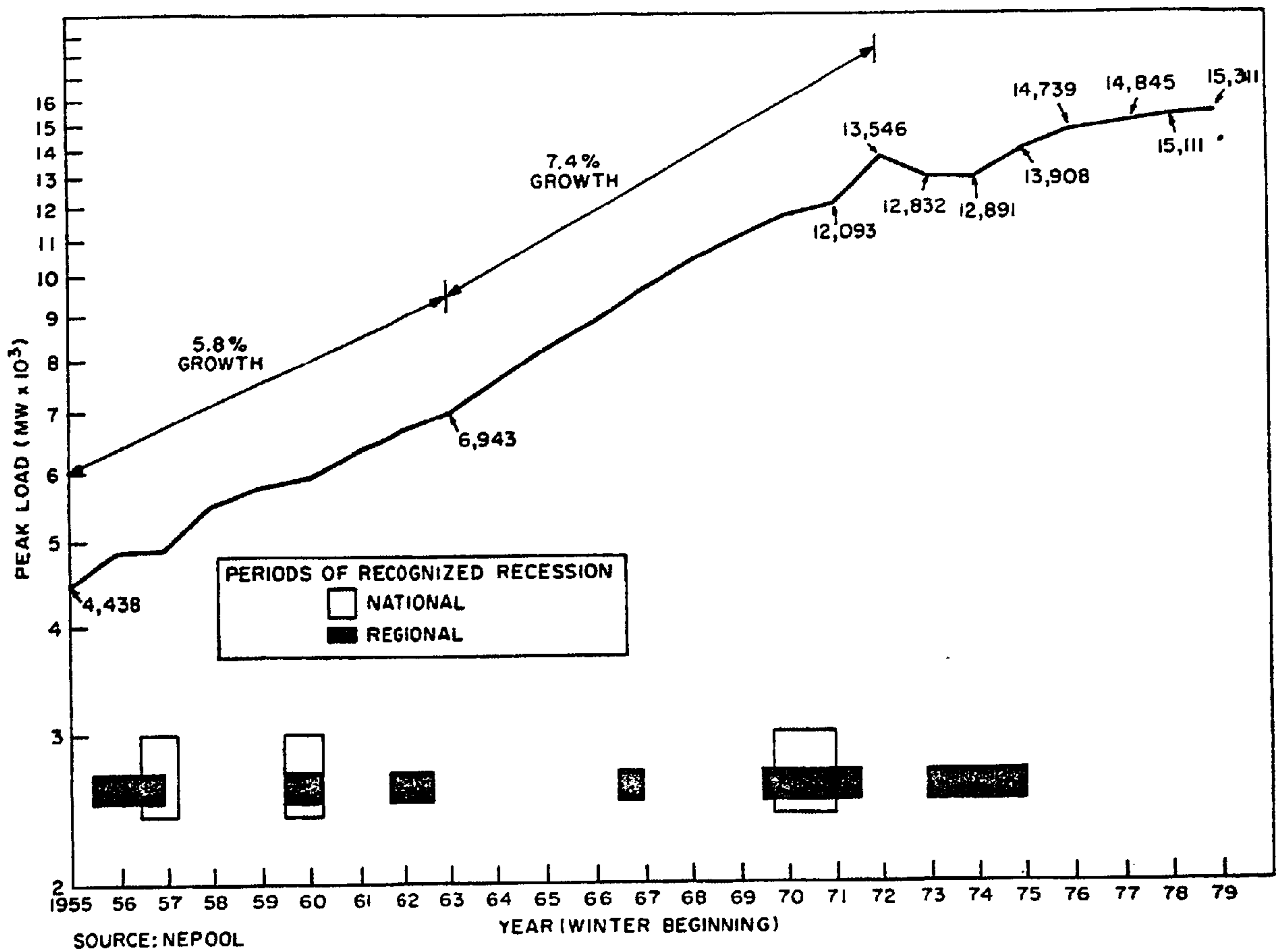

Figure 5-1

TOTAL NEW ENGLAND WINTER PEAK LOAD (1955 - 1979)

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dependency remains unchanged. Southern New Hampshire is expe iencing peak load growth rates of 5-6% because of the rap development of that area. Because of the high cost of ho heating in the region, many New Englanders are turning to wo or solar for heating, supplementing these alternate sourc with electric heat, either resistance heating or quartz hea ers. Although the overall cost of space conditioning is lov to individuals, these changes in consumer preferences for spa conditioning may lead to exaggerated winter peaking patter This trend is being closely watched by utility load foreca ers.

Since load growth trends are downward, the emphasis in gene tion planning has shifted to concerns with the fuel basis power generation and the price and security of supply of fu used for generation. As shown in Figure 5-2, the Pool is he ily dependent on oil for generation. Nearly 60 percent of electrical generation in New England in 1980 was oil-fir Figure 5-3 compares New England to the United States, which only 11 percent dependent on oil-fired generation. Virtua all of the oil used for power generation in New England imported and is subject to the price fluctuations in the wo oil market as well as potential disruptions in delive NEPOOL would like to reduce this dependency on foreign diversify sources of supply and maintain and increase t ability to adapt to changing consumption patterns. To these objectives, the Pool has several options:

- New nuclear capacity
- Conversions of oil units to coal
- Purchase of Canadian power

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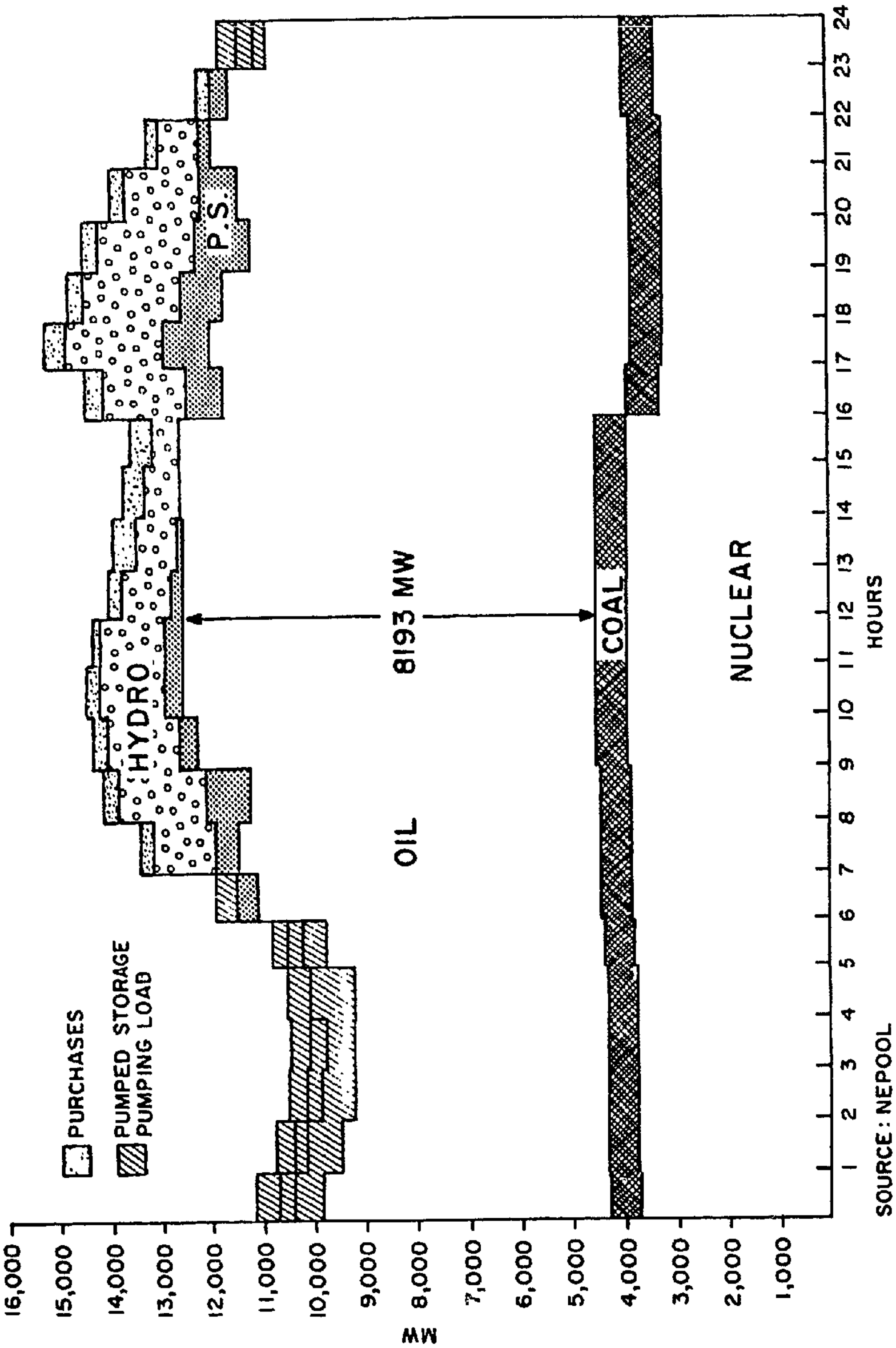
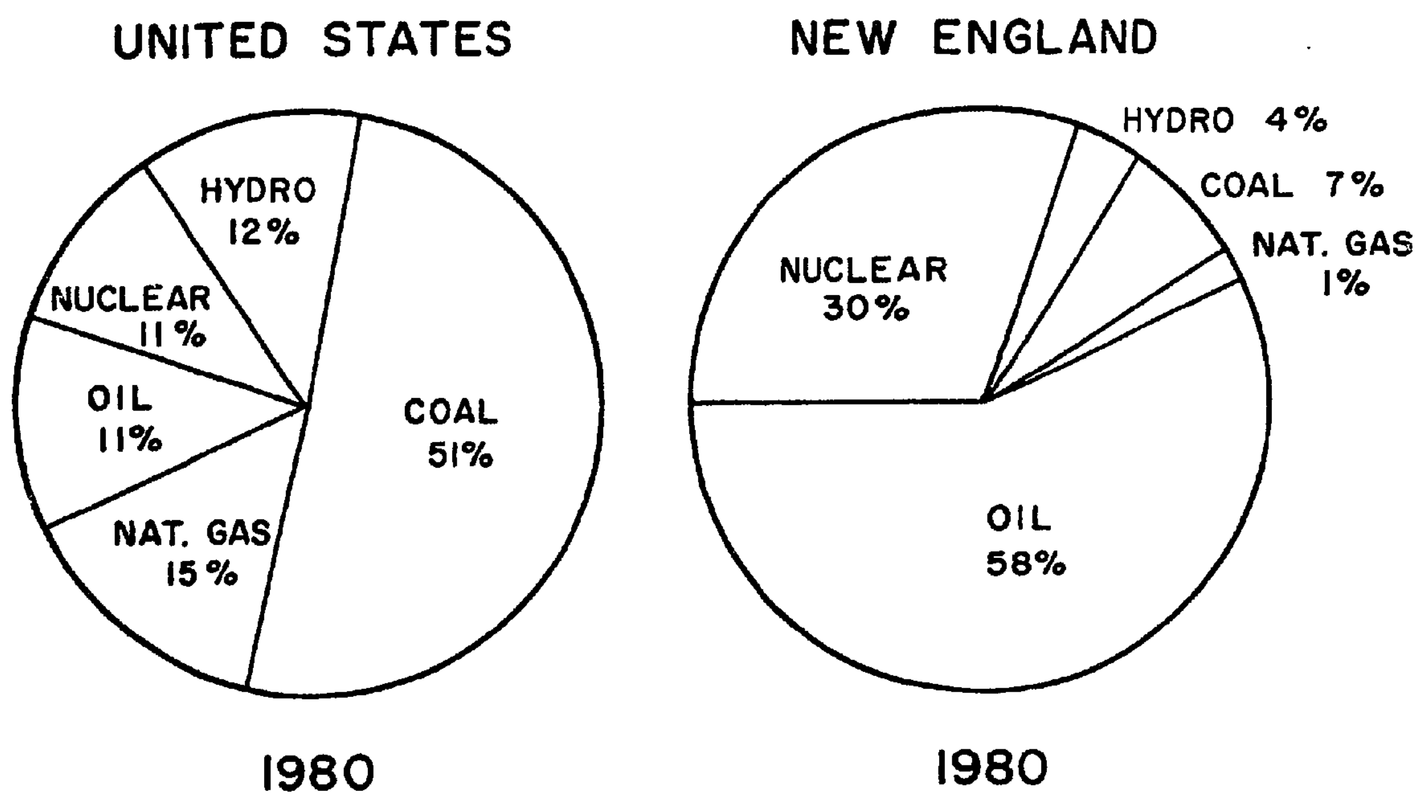


Figure 5-2
NEW ENGLAND PEAK DAY DISPATCH - (DECEMBER 19, 1979)



SOURCE: DOE BOSTON

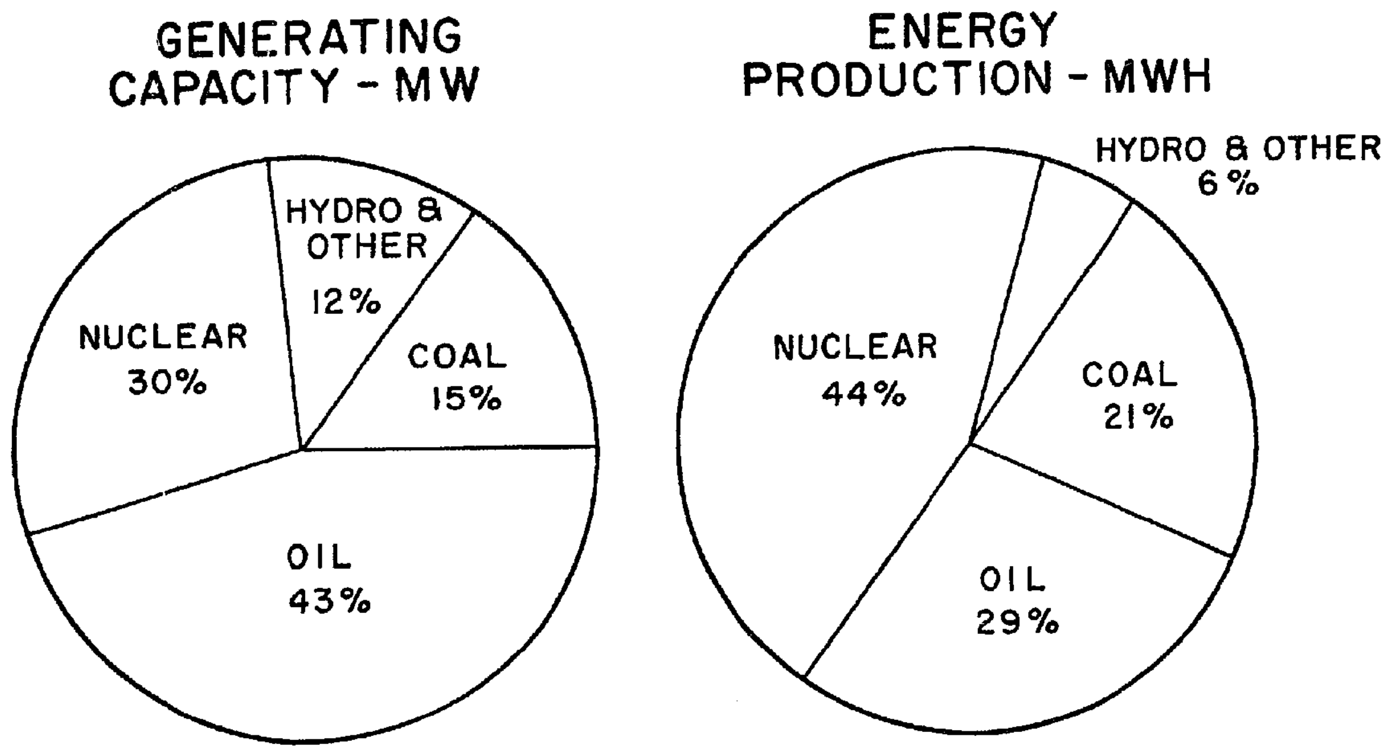
Figure 5-3

FUEL SOURCES FOR ELECTRIC POWER

Nuclear expansion in the 1980's in New England will probably be limited to the three units under construction, Millstone 3, and Seabrook 1 and 2, with a total capacity of 3450 MW. The recent cancellation of the Pilgrim II unit (and those of Charlestown and Montague) illustrates the problems encountered with beginning new nuclear units at this time. The lead times on the units are excessively long, on the order of 14 years, causing significant cost growth in periods of high inflation and interest rates. Because of cost growth and the licensing uncertainties since Three Mile Island, nuclear expansion presents excessive financial risk to many New England utilities, whose financial positions are not strong enough to allow them to accept such risk.

Twenty-four oil units in New England have been assessed as coal convertible (a total of 2760 MW). The conversions will be evaluated by individual utilities taking into account location, age of unit, potential de-rating, and permitting situation. Environmental licensing has taken 2-3 years for conversions already in progress; construction typically requires 1-2 years. Not all of the twenty-four units will be evaluated as cost-effective conversions. NEPOOL uses a planning figure of seven conversions. Even with coal conversions the Pool is significantly dependent on oil during peak day dispatch. Figure 5-4 presents the annual generation mix, given all coal conversions. The New England Energy Park power is targeted toward replacing oil capacity on the system and substituting for coal conversions that are not deemed cost effective.

A utility version of the New England Power exchange (NEPEX) dispatch model was used to evaluate the avoided cost of power that would result from the NEEP project. The NEEP sponsors adjusted NEPOOL announced capacity plans to reflect the current financial and timing constraints.



SOURCE: NEW ENGLAND ELECTRIC SYSTEM

Figure 5-4
PROJECTED SOURCES OF ELECTRIC POWER - NEW ENGLAND - 1990

The 1990 avoided cost calculated using this methodology, ranges from 5.9 to 6.5¢/KWH (expressed in 1981 dollars) which is in excess of the 5.63¢/KWH assumed for revenue projections, indicating that a bargaining range does exist, and that the potential also exists for levelization of power prices to mitigate early year losses for the NEEP sponsors.

The New England Energy Park's status as a qualifying cogenerator under PURPA allows project sponsors considerable latitude in power sales to utilities. It is anticipated that power purchase contracts with more than one utility will be necessary. These contracts may be subject to scrutiny by the Massachusetts Department of Public Utilities (DPU).

In addition to power purchase contracts with individual utilities, transmission agreements will be made with NEPOOL. To facilitate the transmission and dispatch arrangements, the unit will be analyzed by the NEPOOL Planning Committee under their usual procedures. The project will be presented to the Planning Committee in early summer to begin the analysis of system stability and capacity and energy needs. In the interim, discussion of possible contract terms and conditions continues with individual utilities.

5.3.2 Methanol

Market analysis has been performed on chemical feedstock, transportation and turbine fuel markets for methanol. A survey of the chemical methanol market in the United States revealed excess capacity currently and planned additions equal to expected growth in demand. In addition, a survey of the New England area revealed minimum feedstock use; major users are located in the states of New York, New Jersey and Pennsylvania, but total usage is less than half of the projected output of the NEEP project.

The transportation blending market was analyzed briefly. A blending value for methanol was calculated based on backing butane out of the gasoline pool. The value of methanol for use in the gasoline pool was calculated for low concentration blends (less than 10%) in unleaded gasoline. The calculations are based on a comparison versus butane, with the decision to blend in methanol or butane being based primarily on the relative values of the two components. That is, a decision to blend in methanol is, in effect, a decision to back out butane. Two additional important factors in this calculation are:

- Components in the gasoline pool must remain balanced for control of vapor pressure.

- Added value is ascribed to higher octane components based upon the refinery cost of incremental octane.

The blending values calculated are summarized in Table 5-1 below, along with the corresponding forecast for unleaded regular gasoline.

Table 5-1
METHANOL BLENDING VALUE

	(nominal ¢/gallon)		
	1980	1985	1990
Unleaded Regular Gasoline	91.3	185	286
Methanol Blending Value	64.7	134	224

The calculated methanol blending value is about 30% higher than the NEEP methanol price during the late 80's. However, it should be noted that these values for methanol do not account for technical problems such as corrosion and phase separation which may preclude the use of methanol/unleaded gasoline blends by major oil companies.

Despite the projected attractiveness of methanol as a blending fuel, oil refiners have not shown interest in it. This lack of interest may be attributable to the soft gasoline market. The transportation market is therefore regarded as a potentially attractive market which may be available but which is difficult to demonstrate presently. However, EG&G is participating in a methanol vehicle demonstration program with the State of Massachusetts to stay abreast of developments in this market segment.

Methanol market analysis efforts have concentrated on the utility turbine market. Capital shortages in the utility sector coupled with inflationary interest rates and long permitting and construction lead times have dramatically increased the incentives to keep on line the existing 200,000 MW of oil and natural gas fired capacity in the United States. Recent conservation measures together with rapidly increasing utility rates have resulted in a sharp decrease in load growth projections for most sections of the country. A decreased requirement for new large base loaded units has increased the need to consider smaller, more flexible equipment such as combined cycles and simple cycle gas turbines for system expansion. The operation of such units is much enhanced by ultra-clean liquid or gaseous fuels that are available on an as-needed basis.

Although methanol has not been traditionally used as a power generation fuel, it is extremely clean and could, therefore, contribute significantly to decreasing emission problems currently facing the industry. Methanol contains no sulfur, no particulate matter and no nitrogen. It also burns at lower temperatures than petroleum derived liquid fuels or natural gas. It would, therefore, be anticipated to produce significantly lower nitrogen oxides emissions than petroleum based liquids and other synthetic fuels.

Extensive testing, partially funded by the Electric Power Research Institute and Southern California Edison Company, has been performed on methanol as a turbine fuel. These results indicate that with certain minor modifications of the fuel handling system, methanol can be burned in gas turbine units efficiently and with some environmental advantages.

An examination of recent DOE reports indicates that four of the ten largest utilities with multiple gas turbine installations are located on the East Coast. Access to the Eastern Seaboard from the NEEP site via rail and coastal barges, makes this market a particularly attractive target.

Table 5-2 summarizes the potential utility gas turbine demand for methanol in New York/New Jersey under the assumption of conversion of all existing units. This data is based on both FERC Form 1 and Form 12 submittals by these utilities as of 1980. This demand is roughly 1.6 times the estimated NEEP methanol output of 2500 tons/day and is likely to grow with continued decreases in base and intermediate load capacity additions due to regulatory and financial restraints. The nine utilities shown on Table 5-2 presently have gas turbine facilities with the following fuel requirements:

Distillates (No. 2 oil or jet fuel)	54%
Natural Gas	24%
Multi fuel	22%

Additionally, the present distribution of electricity demand produces a seasonal component in the fuel requirements, typically with a distribution such as that shown in Table 5-3.

Conversion of gas turbines to methanol feed has been examined and found to be reasonably low cost. Methanol is more bulky p p

Table 5-2

UTILITY GAS TURBINE EQUIVALENT METHANOL REQUIREMENTS

Utility	Installed Capacity 1980 (MW)	Annual Energy Output (MWH/yr)	Annual Energy Input (Btu/yr x 10^{12})	Annual (1) Methanol Equivalent (tons/yr)
New Jersey				
Atlantic City Electric	375	244,500	3.212	164,750
Jersey Central Power	1,041	626,500	8.381	429,800
Public Service Electric	2,902	539,500	7.598(2)	389,650
New York				
Central Hudson Electric	42	2,000	0.027	1,400
Consolidated Edison	2,549	422,000	6.674	342,250
Long Island Lighting	1,246	182,500	2.333	119,700
Niagra Mohawk	297	84,500	1.170	60,000
Orange & Rockland	84	4,500	0.065	3,350
Rochester Gas & Electric	38	17,500	0.243(2)	12,450
TOTALS	8,574	2,124,000	26.491	1,523,350 = 4,175 tons/day

Notes:

(1) Based on methanol heat content of 19,500,000 Btu/ton.

(2) Based on average full load heat rate of gas turbines surveyed of Btu/kWH.

Table 5-3

TYPICAL DISTRIBUTION OF METHANOL DEMAND

(% of Average Monthly Demand)

January	220%	July	89%
February	159%	August	232%
March	67%	September	114%
April	6%	October	20%
May	74%	November	96%
June	30%	December	95%

than conventional liquid fuels on a Btu basis; therefore, larger storage and transfer facilities are required. Retrofit of existing facilities with special floating roof storage tanks would be most likely. Methanol is not compatible with certain materials, and therefore care must be taken in the selection of materials. Fire protection modification and methanol vapor detection equipment may be required. All of these items can be addressed through engineering redesign coupled with additional capital investment in new equipment. Conclusions based on the preliminary EPRI test program indicate that:

- Methanol is a clean burning fuel. Emission levels are extremely low and would not require the use of special equipment for pollution control;

- Operation and maintenance costs are less than those associated with units burning distillates and approximately equal for natural gas burning units;

- Overall performance and efficiency is better than distillate or natural gas operations.

5.3.3 Methane

With the entry of Eastern Gas and Fuel Associates (and its subsidiary Boston Gas) and Brooklyn Union Gas Company into the NEEP sponsor group, the economic attractiveness of and potential markets for high-Btu gas from the NEEP have been examined. A special engineering study on the addition of methane to the product slate was completed by Bechtel. This study provided the design basis for methane product cost analysis. Concurrently, natural gas supply and demand balances for the region were examined. The results of this market

Natural gas demand grew at a rate of 7% per year in New England and 5% in New York State during the 1960s, but gas supply shortages and subsequent curtailments of pipeline deliveries in the 1970's restricted the rate of growth in demand for natural gas in that decade. However, with the passage of the Natural Gas Policy Act of 1978 and the development of supplemental methane sources, the natural gas supply outlook has been improving over the past three years. This improvement has been reflected already in a dramatic increase in new gas sales reported in New England and New York State in 1980 and 1981.

Figure 5-5 presents projected methane demand in New York State and New England for the 1980s. The region's projected average annual rate of growth is 1% to 2%. This forecast is based on a number of conservative assumptions associated with the current rapid escalation of natural gas prices and a partial decontrol of gas wellhead prices scheduled for 1985. In spite of this modest rate of growth in natural gas demand, the total New England and New York State demand is projected to increase by at least 100 billion cubic feet in this decade and an additional 100 billion cubic feet in the 1990's.

The region's methane demand growth is due primarily to projected conversions of oil heating customers to natural gas in the residential sector.

Historically, all forms of domestic energy have been expensive in the Northeast. For decades, the region reacted to this fact by importing large quantities of foreign oil. Much of this oil was absorbed by the residential market with the result that, compared to other parts of the U.S., the Northeast has a large percentage of gas customers who do not heat their homes with gas. This situation presents a large potential source of market growth and one which is very desirable, from a national

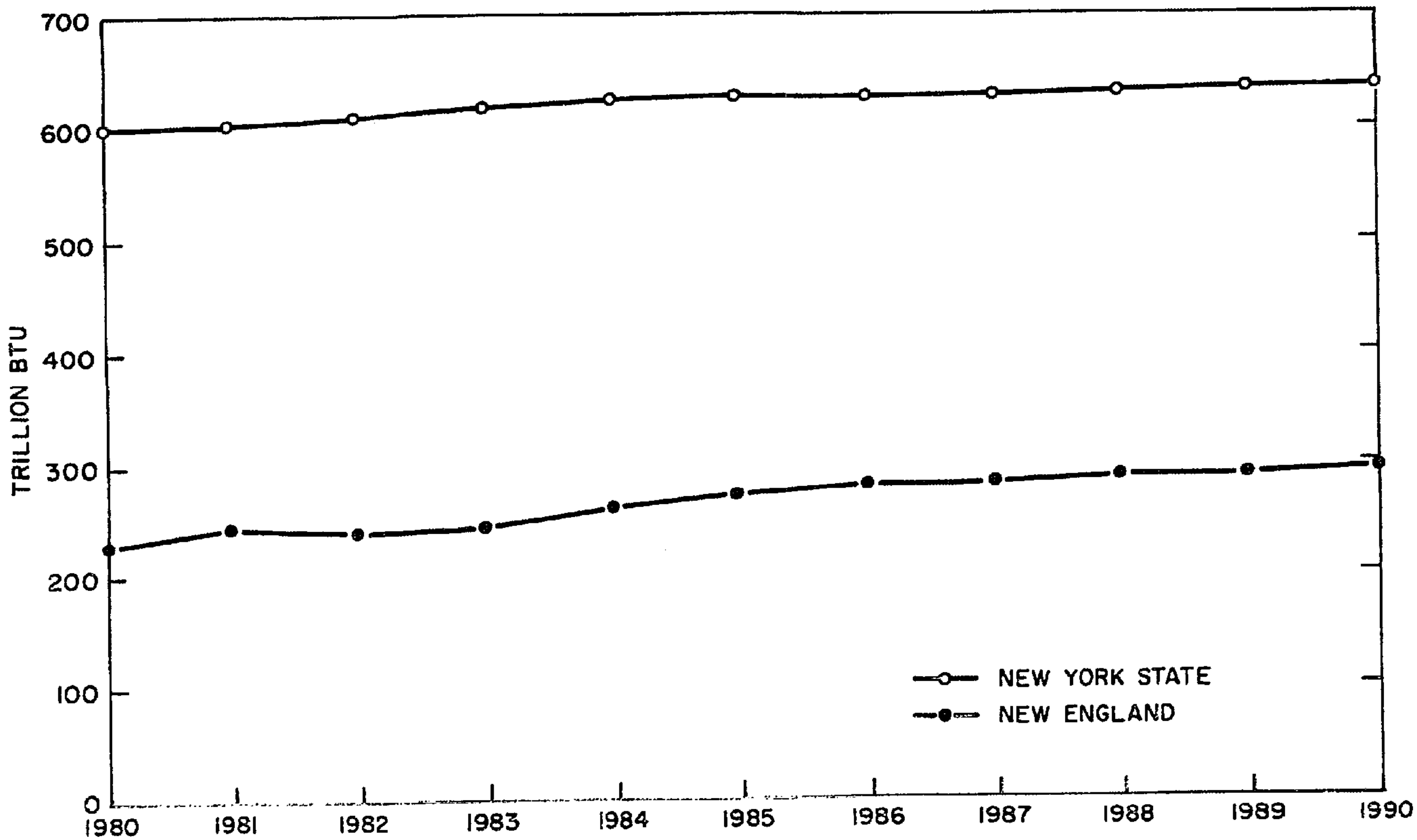


Figure 5-5

PROJECTED FIRM METHANE DEMAND FOR NEW YORK STATE AND NEW ENGLAND policy perspective. The customer who converts to gas heat also tends to convert to gas for hot water heating, further increasing potential saturations.

Two pipeline companies currently supply the New England states with natural gas. Both companies obtain their gas supplies from sources in the Gulf of Mexico, a distance of approximately 1,600 miles. Because of this distance and the fact that New England is at the end of the supply systems, the natural gas supply to New England has tended to be expensive and somewhat fragile with regard to security.

Because of these factors, the New England area was first in the country to look for other sources of gas supply. Among these other supplies are Algonquin's naphtha-based SNG plant, Boston Gas Company's propane-based SNG plant, and the LNG import terminal of the Cabot Corporation in Boston Harbor. Because the outlook for the future is for little, if any, increase in natural gas supplies from domestic sources due to transmission system constraints, the New England utilities will have to continue to look elsewhere for new supplies to meet expected load growth. Possible sources are imported natural gas from Canada, increased LNG imports from Algeria, or other countries, and increased production of SNG gas from new and/or existing plants with liquid or solid feedstocks. All planned supplemental sources to the Northeastern region rely on foreign sources of gas. While the region's geographical location favors imports from Canada, imported energy supplies have political as well as security of supply implications.

The market analysis undertaken by the NEEP sponsor group indicates a growing, climate-sensitive natural gas load in the Northeast, due primarily to the rising cost of home heating oil. The gas transmission and distribution companies have responded to load growth by structuring a number of supplemental supply projects. However, all of these projects depend on foreign sources of supply. NEEP offers a distinct advantage to distributors because of its ability to deliver gas during the winter season from within the region.

5.4 STATUS OF MARKETING PROGRAM

The power marketing program has been based on a PURPA approach with full information exchange with the New England utilities. Extensive meetings have been held with Boston Edison Company, Eastern Utility Associates, Massachusetts Municipal Wholesale Electric Company, and the New England Electric System. Boston Edison has aided the project by performing dispatch analysis on their generation planning simulation model. In addition, information discussions have been held with Central Maine Power and Northeast Utilities.

Qualifying cogenerator status for the facility has been received from the Federal Energy Regulatory Commission; a copy of their order is appended to this volume. Since the NEEP is the largest certified cogenerator in the nation, the placement of the power raises complex issues with regard to dispatch, capacity payments, ownership, operation and appropriate contractual arrangements. Individual New England utilities have offered long-term contracts to small qualifying facilities at 90-95 percent of avoided cost (the fuel component of the cost of generating power in conventional oil-fired thermal units). However, because of the size of the NEEP and the necessity of dispatching at baseload, the contractual arrangements for power placement will be negotiated with more than one member of NEPOOL. Such joint contractual undertakings have been used in support of the Canadian imports.

In the methanol marketing program, the utilities identified in the turbine market survey have been contacted. They have generally confirmed EG&G's analysis on conversion cost and use issues. Letters from Consolidated Edison and Long Island Lighting expressing an interest in purchasing the methanol are appended to this volume. In addition, The Brooklyn Union Gas Company is assessing the potential for substitution of methanol for naphtha at their Green Point, New York, SNG peak-shaving plant and may choose to exercise their purchase option if results of these studies indicate a benefit for methanol conversion.

The NEEP methane marketing efforts have meet with positive responses from potential off-takers. Brooklyn Union Gas, who joined the project primarily because of its interest in purchasing methane, has expressed an intent to off-take at least 20 million cubic feet of methane per day during the winter season (approximately 5 Bcf of pipeline quality gas per year). Boston Gas Company, a wholly owned subsidiary of Eastern Gas and Fuel Associates, also expressed a strong interest in purchasing winter methane.

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6. FINANCE

6.1 INTRODUCTION AND STATUS

At the time the NEEP goes into commercial operation in early 1988, total estimated capital cost of $3.8 billion will have been incurred. These costs include the 1981 dollar estimate for construction of $2.0 billion, the impact of inflation during the five-year construction period on these costs of approximately $0.8 billion, interest on funds borrowed during construction of approximately $0.6 billion and $0.4 billion for working capital and losses during the first year of operation. It is contemplated that funds to meet these capital requirements will be provided by equity sponsors in the amount of approximately $1.1 billion with the $2.7 billion remainder being borrowed (see Table 6-1).

Table 6-1
SUMMARY OF BASE CASE FINANCIAL RESULTS
(Billions of Current Dollars)

Capital Cost		Project Funding	
Construction Cost Estimate	$2.0		
Inflation of Construction Costs	0.8		
Interest During Construction	0.6	Guaranteed Debt	$2.7
Initial Working Capital Deficits	0.4	Equity Contribution	$1.1
Total Estimated Project Costs	$3.8	Total Funding	$3.8

Total Project Cost per Barrel of Oil Displaced: $12.08

Because of the magnitude of this undertaking and the technical risk incurred, the borrowings will only be possible if the credit support is provided by the U.S. Government through the United States Synthetic Fuels Corporation (SFC).

The NEEP financial projections demonstrate that the economic viability of this project depends on the ability (1) to market the project's output under contract, and (2) to mitigate the project's risks. Given the location of the project, and New England's dependence on foreign oil, the project's output will be marketable provided it is competitively priced. Project risks, in particular risks associated with performance shortfalls and capital growth, were analyzed based on the engineering risk mitigation strategy and the anticipated participation in the Cool Water project.

The project management has developed a staged approach to funding consistent with the project's technical development. Funding for the feasibility stage of $10 million has been provided by the equity sponsors and a grant from the Department of Energy. The funding of $16 million through the pre-construction stage will also be provided by the equity sponsors contingent on the prospects of financial assistance in the form of loan guarantees from the SFC to assist in funding during the construction phase. Assuming such guarantees are provided, funding during the construction phase will be shared 30% by the equity sponsors and 70% from borrowings by the project. As is typical in construction financing, the initial debt capital will be provided by commercial banks under a revolving credit facility with such interim financing ultimately repaid with the proceeds of the permanent financing.

The financial projections indicate that NEEP is an economically viable project. The returns are sufficient to attract the necessary equity capital and provide adequate debt service protection to the lending institutions. However, it is impractical to assume that all risks can be minimized to the point of insignificance during the construction period and the initial years of operation. For this reason, the project is requesting assistance from the SFC initially in the form of loan guarantees with the possibility that price guarantees may be requested after completion risks are removed.

6.2 COST METHODOLOGY

To facilitate the estimate of the capital cost of coal conversion, each process system was further divided into plants utilizing the architect/engineer's (A/E) definitions.

Vendor estimates were obtained on most major equipment and the remaining equipment was sized and estimated by Bechtel. The approaches used can be summarized as follows:

a) Vendor all-in quote with other items, i.e., materials, tie-ins, etc., factored.

b) Major equipment identified and sized. Vendor input on major equipment price. Other items from historical information.

c) Major equipment identified and sized; cost fractored from historical information. Other materials and labor added on a percent basis.

d) Major facilities and equipment sized. Quantities of other materials estimated. All items were priced using historical information.

e) Factored adjustment to plant cost due to add on methanation system needs.

The cost estimate for the power plant was derived from comparison to a large combined-cycle power plant engineered and constructed by the project's A/E, Bechtel, and presently in commercial operation. Vendor quotes on the major mechanical equipment were obtained and confirmed the estimate developed by Bechtel.

Field costs were reported by materials, labor, and subcontracts. All in vendor quotes were placed in the subcontract category.

Specific areas where vendor information was significant are as follows:

- Coal Receiving and Handling - Budget estimates, including installation, were received from the Mid-West Conveyor Company for the coal conveyor systems at the terminal and on site. Budgetary prices from Heyl & Patterson and PACECO Bulk Handling Divison provided the basis for the unloader estimate.

- Texaco Gasification Process - A standard type B design package was obtained from Texaco Development Corporation for the conceptual gasification plant design. Major equipment for eight trains was quoted by Combustion Engineering Power Systems.

- Air Separation - A budget estimate was obtained from Air Products and Chemicals, Inc., for the 8,500 tpd 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 systems 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 plants. This quote 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 carbonyl sulfide hydrolysis reactors.

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

- Methanation - Methanation unit design was based on Cono-Meth technology licensed by Conoco. The installed cost of the unit was estimated by Bechtel.

- Electric Power Generation - Information on the cost and performance of the combined-cycle power plants was obtained from General Electric, Westinghouse, and Brown Boveri. Rotoflow and Elliot provided performance and cost information on gas expanders.

All costs shown in Table 6-2 are presented in October 1981 dollars. Estimates used, which are developed for other time frames, are adjusted based on Bechtel's actual experience. The following escalation rates were noted for materials between March 1980, and October 1981:

a) Process Plant (15 percent)

b) Power Plant (9 percent)

Material and subcontract costs were adjusted using these rates. All labor was adjusted by applying the October 1981 labor rates to the estimated job-hours.

Table 6-2
SUMMARY OF COST
($ Millions)

ITEM	CAPITAL
Coal Conversion to Raw Gas	$1.243.3
Fuel Gas Cleanup	80.7
Synthesis Gas Cleanup	206.3
Methanol Synthesis	88.2
Methanation	43.8
PROCESS PLANT SUBTOTAL	$1,662.9
Power Plant	325.6
NEEP PLANT COST (1981 $)	$1,987.9
Initial Working Capital Deficits	447.0
Inflation of Construction Cost	800.0
Interest During Construction	634.0
TOTAL CAPITAL REQUIREMENT	$3,869.0

In general, indirect costs were estimated using the following approach. Field distributables were estimated at 80 percent of labor. Engineering and home office costs were included at 12.5 percent of the direct material costs, labor costs, and distributables. Lower percentages were applied to the gasifier and the power plant for engineering and home office costs.

Certain precautions have been taken to offset the risk associated with cost overruns. Contingency is included to cover variations in pricing, quantities, and productivity, and is assigned on a plant basis.

Pre-operational expenses were added to complete the estimate of capital required for the project.

6.3 ECONOMIC VIABILITY

Economic viability of this project hinges on its location in a market where foreign oil is directly displaced by the NEEP products and on the region's acceptance of the need for a sophisticated coal conversion facility for the continued economic growth of the region. This viability appears robust under a variety of possible future scenarios. Table 6-3 shows the sensitivity of the financial results to the major project risks.

The lack of real growth in revenues and performance shortfalls are the risks with the greatest impact on the project's financial results. For this reason, the project has devoted its efforts to accomplishing the marketing program described in Section 5. As a result of these efforts, NEEP is now reasonably confident that it can sell the project's products on an oil displacement basis. An important factor in the project's economic viability is its ability to displace foreign oil at better than a Btu-for-Btu basis. The project's New England location ensures that its power output can compete p p

Table 6-3

SENSITIVITY OF FINANCIAL RESULTS

(Billions of Current Dollars)

	Internal Rate of Return	Maximum Total Equity $	Maximum Total Equity Year
Base Case	30%	2.0	1996
100% Equity	10	2.9	1988
Marketing Risk*			
0% Real Revenue Increase	(2)	3.2	2001
2% Real Revenue Increase	33	1.6	1994
3% Real Revenue Increase	36	1.4	1990
Performance Shortfalls			
80% Maximum Operating Factor	27	2.5	1997
70% Maximum Operating Factor	20	3.1	1997
60% Maximum Operating Factor	(4)	4.1	2001
Cost Growth			
15% Cost Growth	24	2.7	1997
30% Cost Growth	15	3.3	1997
30% Cost Growth and One Year Delay in Start-up	12	3.4	1997
Inflation and Interest Rates			
8% Inflation, 4% Real Interest Rates	31	2.2	1995

* In the 0% case, coal costs also show 0% real growth, but in the 2% and 3% cases coal costs show real growth of 1% and 2% respectively.

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against foreign oil-based power plants which have low conversion efficiencies relative to the combined cycle unit proposed for NEEP. One kilowatt hour of power generated by the project requires 7750 Btus of medium Btu fuel gas, while the oil-fired New England power units require 9,600 to 13,000 Btus of No. 6 fuel oil.

Even given 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 project proposes to structure the SFC's price guarantee and the marketing contracts in such a way as to ensure project viability in the early years of operation, with any disbursements under a price guarantee being recouped by the SFC in the later years of operation. In addition, the project is sensitive to the vagaries of the world oil market. The project is not economically viable without a real increase in world oil prices. While the sponsors believe the 1% real increase in oil prices assumed in the Base Case is a conservative assumption, a price guarantee is also intended to protect the project from sustained oil price weakness.

The accomplishment of the project's marketing objectives will lead to economic viability only if the other major risks of performance shortfalls and cost growth are controlled. The project's risk mitigation strategy depends both on conservative engineering and design estimates and on financial risk analysis. The engineering and design risk mitigation strategy, which concentrates on the use of commercially proven technology, is contained in Section 4. The project's proposed participation in the Cool Water project is designed to transfer directly to the project the results of the Cool Water demonstration, giving NEEP a high level of process and project information. The NEEP project schedule has been tailored to follow closely the Cool Water project schedule. This integration will give NEEP the benefits of design, construction, and operating experience of Cool Water.

The financial analysis of project risk maps the financial consequences of that risk by evaluating the probabilities of the major sources of risk. For this analysis, the project uses its proprietary risk analysis model and the methodology described in The Rand Corporation's study Understanding Cost Growth and Performance Shortfalls in Pioneer Plants. The application of this analysis to the NEEP financial projections provides an indicator of financial risk to the SFC and the equity sponsors. It also allows a measure of the probability that the amount of the SFC's obligational authority reserved for the project will be disbursed and not later recouped.

The project's maximum operating factor is one of the most important project risks. For this reason, the Base Case design production of the plant is 55 trillion Btus of medium Btu gas per year, 16 2/3% below the 66 trillion Btus of gas expected to be produced. The returns to the equity sponsors are very sensitive to operating factors in the early years of operation. For the purpose of projecting financial results, the project used conservative operating factors for these early years: 60% for the first twelve months of operation, 75% for the second twelve months of operation, and 90% for subsequent years. The capacity factors for the first two years were estimated based on the follow-on approach to Cool Water and the present level of the engineering and environmental work done.

Cost growth primarily affects the total equity contribution of the sponsors. The sponsors and the most serious of the potential sponsors have all recently been involved in large capital projects. This is particularly true of EG&G, which has had substantial commercial success managing first-of-a-kind capital projects. This experience has resulted in substantial attention to evaluation of the risk of cost growth.

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The project applied stringent risk analysis to the capital cost estimates and devoted its engineering resources to those areas most likely to generate cost growth. This plan resulted in a concentration of attention on those portions of the plant which have not been in commercial use before, and in site-specific work including on-site and off-site unit configurations, complete soils and hydrology data, design of the water system and final definition of all access routes to the project. In addition, the major environmental and health and safety requirements have been identified, and permits have been or are in the process of being applied for.

This approach to cost overruns, together with the follow-on approach to the Cool Water project, allows the project to make reasonable estimates of the cost growth risk. The project has attempted to place specific estimates of cost uncertainty, rather than overall gross "contingency" factors, on various parts of the project, particularly allowing for new technology. This approach has enabled NEEP to perform risk analysis on the project and to estimate the effects of cost growth with a reasonable degree of confidence.

6.4 EQUITY SPONSORS

NEEP's present sponsors and the investment banking firm of Lehman Brothers Kuhn Loeb, Inc., are in the process of contacting potential equity sponsors. NEEP is seeking indications of interest in equity commitments, conditioned on entering Phase II of the SFC's second solicitation. There are now a number of potential sponsors willing to devote substantial management time and engineering effort to NEEP, including detailed reviews of the cost estimates. But these potential sponsors are unwilling to make any funding commitment to any project seeking SFC assistance until the project is chosen for Phase II. Assuming NEEP is chosen for Phase II, these potential sponsors have indicated an interest in participating in NEEP. In addition, NEEP has arranged a series of meetings over the third quarter with new potential equity sponsors.

6.5 UNIT PRODUCTION COST

Unit costs of production have been calculated for all of the Energy Park products. These costs have been calculated on a life cycle basis, including depreciation, interest, feedstock, and operating costs. Tax credits have not been taken into account in unit production costs, nor have returns to the sponsor group. The actual required selling price will depend on the revenue targets of the final group of sponsors as well as the group's ability to utilize the tax benefits. Thus, the unit costs of production discussed below are breakeven costs which cover variable costs and capital recovery.

Figure 6-1 shows the cost of electric power generated from NEEP (in 1981 dollars) compared to an assumed market price based on the avoided cost of oil-generated power. The market price is the fuel component only of electric power generated from No. 6 oil in a conventional thermal unit. No. 6 oil is assumed to inflate, in real terms, at a rate of 1% per year from a base of $32.00/barrel established in fourth quarter, 1981. As shown in the chart, power from NEEP is in the competitive range of oil-generated power in the 1990s. This comparison is the least favorable to NEEP because it assumes that no capital charges accrue to the oil unit; that is, the oil-fired capacity is assumed to be available and fully depreciated. In fact, the load and capacity analysis contained in the marketing section indicates that new capacity will be needed by NEPOOL in the early 1990s and that a more proper comparison would be against other new sources of generation capacity.

Table 6-4 shows the unit production cost of methanol from the NEEP in both current and 1981 dollars. These costs are higher than the assumed 1981 price of 46¢/gallon but the production of methanol confers gasifier load leveling cost benefits on the projection of power and methane.

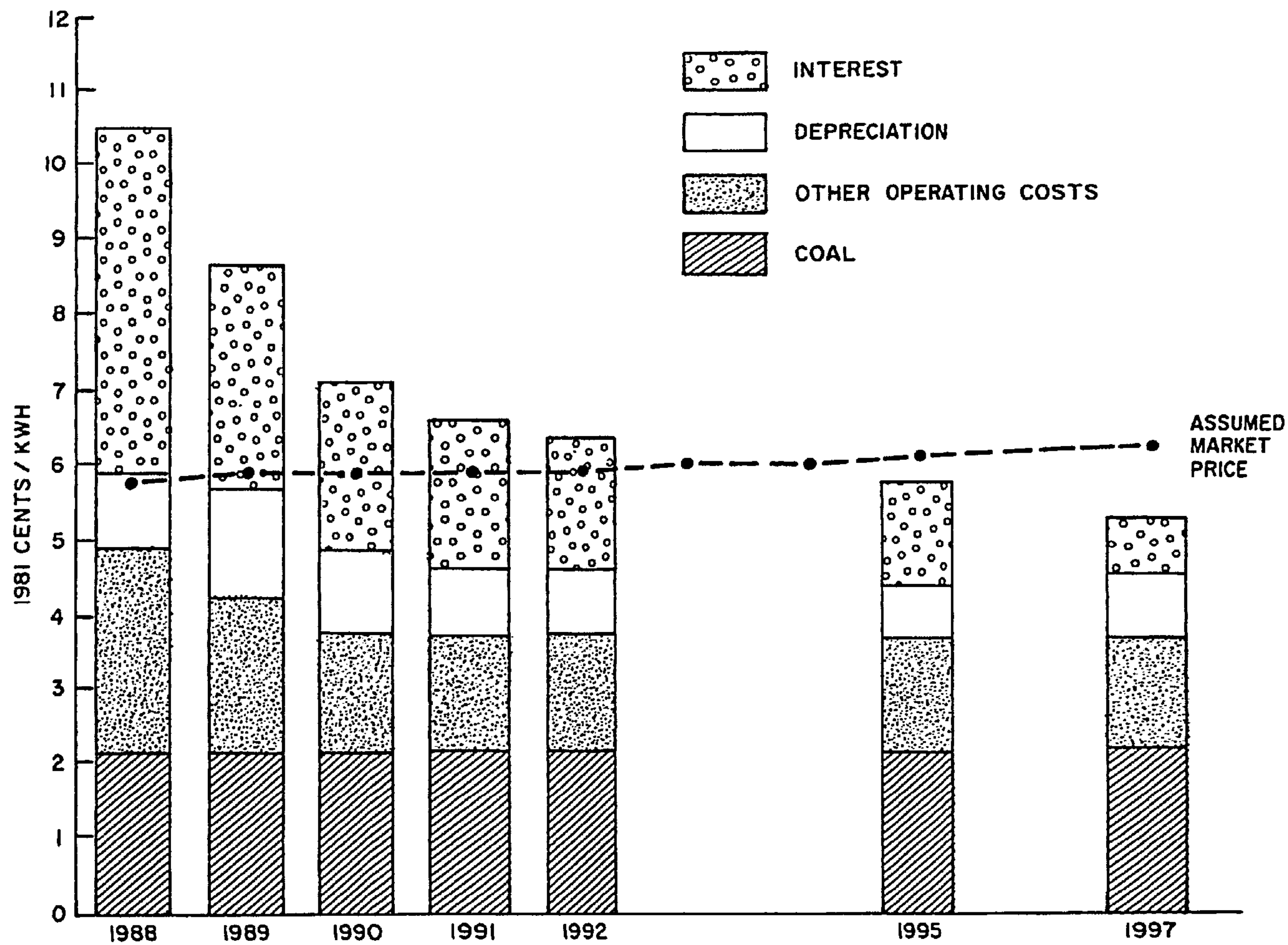

Figure 6-1

UNIT COST OF PRODUCTION - POWER

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Table 6-4

METHANOL UNIT COST OF PRODUCTION

(Millions of Current Dollars)

	1988	1989	1990	1991	1992	1995	1997
Coal	$ 21	$ 35	$ 45	$ 50	$ 54	$ 66	$ 75
Other Operating Costs	30	40	39	43	46	56	64
Depreciation and IDC Amort.	14	28	28	28	28	28	28
Interest	59	61	61	61	61	53	47
TOTAL	$124	$164	$173	$182	$189	$203	$214
Units (millions of gallons)	56.2	88.7	107.5	112.4	112.4	112.4	112.4
Cost Per Gallon (current dollars)	$2.21	$1.85	$1.61	$1.62	$1.68	$1.81	$1.90
Cost Per Gallon (1981 dollars)	$1.34	$1.05	$0.85	$0.80	$0.78	$0.69	$0.63

The unit costs of production for the methane output from the project are shown in Table 6-5. As pointed out in the marketing section, New England gas distributors are currently paying \$10-\$12/MMBtu for winter gas, so that methane from the Park can be assumed to be in the competitive range.

Table 6-5

METHANE UNIT COST OF PRODUCTION

(Millions of Current Dollars)

	1988	1989	1990	1991	1992	1995	1997
Coal	$ 21	$ 35	$ 45	$ 50	$ 54	$ 66	$ 75
Other Operating Costs	30	40	39	43	46	56	64
Depreciation and IDC Amort.	12	25	25	25	25	25	25
Interest	53	55	55	55	55	48	42
TOTAL	$116	$155	$164	$173	$180	$195	$206
Units (10^{12} Btu)	3.8	6.0	7.3	7.6	7.6	7.6	7.6
Cost per MMBtu (current dollars)	$30.53	$25.83	$22.47	$22.76	$23.68	$25.66	$27.11
Cost per MMBtu (1981 dollars)	$18.55	$14.67	$11.92	$11.29	$10.98	$ 9.71	$ 8.86

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7. SITE SELECTION

7.1 INTRODUCTION

Fall River, Massachusetts, has been identified as the NEEP site. The site selection process for the NEEP project, initiated in mid 1979, is responsive to the National Environmental Policy Act, the Massachusetts Environmental Policy Act and local requirements.

The NEEP site selection process was based on selection of a site that met project resource requirements, was potentially licensable, was accepted by the surrounding communities, and was capable of being developed at minimum cost.

General siting requirements were identified and applied at two different levels. The first level screening was designed to identify and evaluate potential areas within the New England region that would be capable of supporting the proposed facility. The second stage screening was designed to evaluate specific sites in greater detail.

A basic premise of the NEEP project is that it will assist in meeting future energy needs of the New England region. Thus, the site-selection process only considered sites within the region.

Due to the size and complexity of the NEEP project, a minimum of 500 acres, and a preference for 1000 acres or more, was required for a site to be considered. A larger site would provide greater flexibility in site layout and more opportunities for mitigating environmental impacts through the use of buffer zones.

The coal gasification process requires 12 - 18 million gallons/day of water. Therefore, a site with access to a large water supply was required; however, relatively low quality water will meet most of the project's needs. It was determined that the effluent from a sewage treatment plant could be a possible source for most of the plant's process water requirements.

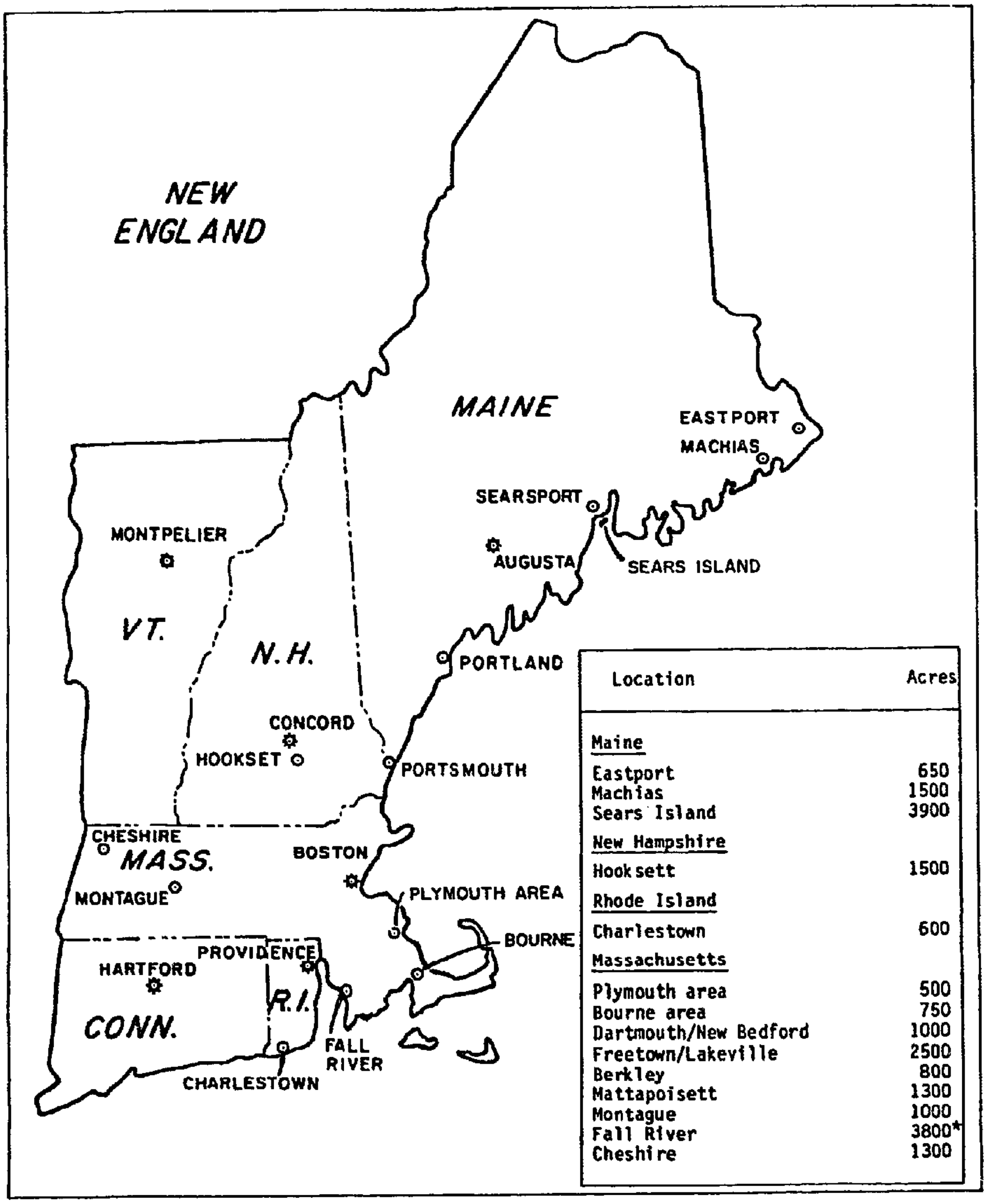
General environmental compatibility was an important criterion because of the need for the proposed project to meet a wide range of environmental regulations. Environmental considerations included air quality, water quality, land-use patterns, and general site development constraints. Air quality screening included determining existing ambient air quality with respect to national and state standards and the proximity to Class I Prevention of Significant Deterioration areas. Water quality screening included evaluating the existing quality of water bodies in the vicinity of the sites and reviewing water-use classifications and plans. Land-use screening included the evaluation of potential land use conflicts and the potential for mitigating them. General site development screening evaluated the need for actions such as dredging channels and filling wetlands.

Because the proposed project will require large quantities of raw materials and produce significant outputs, access to suitable transportation was an important criterion. Approximately 3.5 million tons of coal/year will need to be transported to the site by coastal shipping, so access to a deep water port was required. Access to the regional power grid, proximity to gas pipelines and utility rights-of-way were considered important to facilitate transport of plant output. Access to adequate surface roads and a nearby highway system was also an important criterion.

7.2 REGIONAL SELECTION

Initial identification of suitable areas involved extensive contact with state industrial development agencies and a review of available siting studies from other proposed major industrial facilities. These activities identified sites along coastal Maine, New Hampshire, Rhode Island, and western and southeastern Massachusetts. These sites are identified in Figure 7-1.

The three coastal Maine sites are noteworthy primarily for their natural deep-water harbors. All three have been considered for possible energy facility sites. The Pittston Company has proposed to



Location	Acres
<u>Maine</u>	
Eastport	650
Machias	1500
Sears Island	3900
<u>New Hampshire</u>	
Hooksett	1500
<u>Rhode Island</u>	
Charlestown	600
<u>Massachusetts</u>	
Plymouth area	500
Bourne area	750
Dartmouth/New Bedford	1000
Freetown/Lakeville	2500
Berkley	800
Mattapoisett	1300
Montague	1000
Fall River	3800*
Cheshire	1300

*Additional land has been purchased from the city of Fall River. Total site is 4500 acres.

Figure 7-1

POTENTIAL NEEP AREAS EVALUATED

build an oil refinery at the Eastport site (near the Canadian border). The Machias site, located 30 miles southwest of Eastport, was proposed as a site for a potential LNG terminal. The Sears Island site, located in the northern part of Penobscott Bay in Maine's central coastal region, has been proposed as the site of an oil refinery, a nuclear power plant, and a coal-fired power plant. The Maine Public Utilities Commission denied permission to construct a coal-fired power plant at this site at the scale originally proposed; the sponsor is presently conducting its own feasibility study for a coal gasification/combined cycle power plant. Land availability at two of the three Maine sites was questionable. All three sites are located in sparsely populated regions, not well served by existing means of transportation. Because of distance, transportation costs to these sites would be greater than sites in southern New England.

The Hooksett, New Hampshire, site is located in southern New Hampshire between Concord and Manchester along the Merrimack River, near the site of an existing coal-fired power plant. Coal for the Hooksett site would have to be delivered by train, as the river is not navigable. The potential is high that the handling of such large volumes of coal by train would pose a problem on the existing railroad network.

The Charlestown, Rhode Island, site is located on the south coast of the state and was formerly the site of the Charlestown Naval Air Station. The area surrounding the site is sparsely populated and has traditionally been used for recreation and fishing. The area has valuable wetlands and estuarine systems. Available water supply in the area is limited. Most of the residents in the community rely on groundwater for domestic water supply; substantial additional groundwater development could likely lead to saltwater intrusion of local aquifers. The nearest deep-water port facilities are located in Portsmouth, Tiverton, and Providence, Rhode Island. The Charlestown site was proposed by the New England Power Company (NEPCO) for the development of two nuclear power plants. Following significant local opposition, NEPCO canceled its plans for the nuclear units. The site, which was under the jurisdiction of the U.S. General Services Administration, was recently transferred to the U.S. Fish and Wildlife Service and the State of Rhode Island. This transfer of ownership will likely result in the continued use of the area as a wildlife preservation and conservation area.

Two sites in western Massachusetts were evaluated; one in Montague, located along the Connecticut River, and one in Cheshire near the Hoosic River. The Montague site was proposed for the development of two nuclear power plants by Northeastern Utilities Company. The site would use water from the Connecticut River, one of the largest rivers in New England. The Chesire site would use the Hoosic River as a water source. Both western Massachusetts sites would require rail transport of coal, a concern due to the present condition of the New England rail network. The Chesire site had relatively good access to rail transport and was in an economically depressed area, which would have a favorable effect on labor availability since the project could draw from the underemployed labor force in nearby Pittsfield and North Adams. The major potential drawbacks included rough topography, and associated site preparation costs, and questionable water supply. EG&G entered into an option agreement for the purchase of this site during January 1980; however the option was ultimately not exercised.

After consideration of the numerous areas in Maine, New Hampshire, Rhode Island, and Massachusetts, the selection was narrowed to three alternative areas in southeastern Massachusetts. In summary the sites north of Cape Cod, Massachusetts, were eliminated due to logistical and economic factors related to coal delivery. While the Maine sites showed good potential for deepwater port development, the added costs associated with the long transportation distances were prohibitive. Additionally, the remote northern sites had limited labor markets and posed difficulties with respect to product marketing. With these limitations associated with sites north of Cape Cod, attention was focused on more southerly locations.

Three southeastern Massachusetts areas were identified because they showed good potential for process water availability and offered several options for transportation of raw materials and products. The areas are the Taunton River Basin area (including Fall River, Freetown, and Somerset); Otis Air Force Base, Bourne area (Cape Cod); and the Plymouth area. These areas were subjected to a more formal site selection evaluation on the basis of several selection criteria. The criteria were assigned a weighting based on their relative importance to the success of the project -- i.e., land and water availability were considered the most important criteria, while proximity to the region's electrical grid and natural gas distribution were of lower relative importance. The criteria and relative weighting are as follows:

- land availability (8)
- water availability (8)
- proximity to deep-water port (7)
- proximity to rail lines/highways (6)
- environmental constraints-air quality, water quality, solid waste disposal (5)
- land use conflicts (4)
- local attitudes/policies regarding industrial development (3)
- proximity to electricity grid (2)
- proximity to natural gas distribution (2)
- labor pool availability (1)

Each of the three regions were evaluated for each of the ten criteria according to the following rating:

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3 Excellent - Meets project requirements

2 Good - Could satisfy project requirements with some modifications

1 Fair - Barely satisfies minimum requirements

0 Poor - Does not satisfy minimum requirements

The relative weighting for each criteria multiplied by the rating yielded a score; the sum of all the scores for each site was compared for selecting the site that was deemed most suitable for development of the NEEP project. The results of the regional selection process are shown in Table 7-1.

As illustrated by this analysis, the Taunton River Basin (primarily Fall River) best satisfied the basic siting criteria. In particular, it was the only region with access to an existing deep-water channel and an adequate water supply. Water supply and conflict with existing land uses were significant problems in both the Bourne and Plymouth areas.

The Taunton River area revealed a good potential water supply situation, large parcels of available land, a good labor supply, a variety of transportation options, and a receptive public and political atmosphere.

Land availability in the Taunton River Basin was considered excellent; EG&G has subsequently placed a 4500 acre-parcel under a purchase option agreement for project development. Water availability was judged to be good, with the effluent from the Fall River secondary sewage treatment plant targeted to supply the majority of the industrial grade process water. The Mount Hope Bay and Taunton River

Table 7-1

SITE SELECTION MATRIX

	Taunton River Basin		Otis Air Force Base Area		Plymouth Site	
	Rating	Weighting	Rating	Weighting	Rating	Weighting
Land availability (8)	Good (2)	16	Excellent (3)	24	Fair (1)	8
Water availability (8)	Excellent (3)	24	Poor (0)	0	Fair (1)	8
Proximity to deep water port (7)	Excellent (3)	21	Fair	7	Fair (1)	7
Proximity to rail lines/highways (6)	Good (2)	12	Fair (1)	6	Fair (1)	6
Potential environmental constraints (5)	Excellent (3)	15	Fair (1)	5	Good (2)	10
Absence of obvious land-use conflicts (4)	Excellent (3)	12	Fair (1)	4	Good (2)	8
Local attitudes/policy re: industrial development (3)	Excellent (3)	9	Poor (0)	0	Good (2)	6
Proximity to electricity grid (2)	Good (2)	4	Fair (1)	2	Excellent (3)	6
Proximity to natural gas distribution system (2)	Excellent (3)	6	Fair (1)	2	Good (2)	4
Labor pool availability (1)	Excellent (3)	3	Fair (1)	1	Excellent (3)	3
Total		112		51		66

system has channel depths of 35 feet as far north as the Shell Oil terminal in Fall River and the Montaup Power Plant in Somerset. Preliminary studies indicate that navigational problems caused by fog or ice are not likely to be serious except in unusual circumstances. In severely cold weather, normal vessel traffic tends to keep channels open.

7.3 NEEP Site Selection

The second phase of the siting analysis took a more detailed look at potential sites in the Taunton River Basin area because of its favorable transportation and water supply situations. Sites investigated included Acushnet Saw Mill property in northeastern Fall River; the Algonquin SNG facility in Freetown; land in Dartmouth (near the New Bedford line), Freetown and Lakeville (near the Lakeville Ponds), and Berkley.

The Acushnet property became a prime site for consideration because it was a large parcel of land under single ownership. The site is close to potential water sources (South Watuppa Pond, Lake Noquochoke, Copicut Reservoir and the Fall River Sewage Treatment Plant), is in a relatively isolated location, and in proximity to utility transmission rights-of-way (gas and electric power lines pass directly through the site).

The Algonquin site in Freetown had limited land and is close to residential development. The Dartmouth/New Bedford site is located near the New Bedford Industrial Park. The parcel is owned by a number of people, representing a potential problem. The site is located very close to the Acushnet Cedar Swamp and the aquifers which supply the groundwater for the town of Dartmouth. The parcel of land in Freetown/Lakeville was also owned by a number of individuals. It had low-density residential development and a neighborhood school close to the boundary. In addition, the site was close to the Lakeville

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Ponds which serve as the primary drinking water source for the cities of New Bedford and Taunton and several smaller towns. The site in Berkley was eliminated from consideration when a site inspection revealed residential development on parts of the parcel which were held under separate ownership, and that water supply would pose a potential problem.

The Acushnet Saw Mill property in Northeastern Fall River satisfied the critical requirements of the proposed coal gasification/combined cycle power plant and became the selected site.

The developers have secured a parcel of land of more than adequate size, providing considerable flexibility in developing the ultimate plant design and layout specifications. The surrounding area is essentially undeveloped; therefore, populated areas can be readily buffered by use of natural features.

An excellent transportation infrastructure exists, including a deep water channel in the Fall River harbor, rail access to the waterfront with connections to all major lines, and good highway and air access. Both power lines and pipe lines are prevalent in Fall River, due to the close proximity of two power plants, a synthetic natural gas plant, and an oil products terminal on the Taunton River. The power line network provides ready access for the power facility's electricity output.

No obvious environmental constraints have been discovered. Fall River is in attainment for SO_2, NO_2, and CO but nonattainment for TSP and ozone. Unless rural Fall River, where the NEEP site is located, is redesignated as attainment for TSP, the Offset Policy rather than the PSD program will be followed. As the site area is surrounded by undeveloped land, there are no land use conflicts.

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Water resources appear to be more than adequate, with an estimated available supply of industrial quality water in excess of 20 million gallons per day which does not include waste water treatment effluent. A water supply scheme has been worked out with the City of Fall River utilizing water to which they hold rights.

The region has been economically depressed for a number of years, exhibiting one of the highest unemployment rates in Massachusetts. The populace and government officials in Fall River and surrounding communities are receptive to industrial development. These cities and towns have been encouraging development of a sound industrial base for a number of years.

The natural systems and environmental situation in the southeast region of Massachusetts are compatible with the type of activity being proposed. Given the need for new energy sources in the Northeast, and the desire to use domestic coal reserves, NEEP represents a relatively clean means of accomplishing these ends. The ambient air quality is not expected to be adversely affected to any significant degree since, in using the most modern technology, many of the key pollutants are reduced in concentration prior to or during combustion of the fuel. Water quality impacts are expected to be positive overall. The ultimate goal is to design a facility with minimal wastewater discharges through the incorporation of process water treatment steps which enhance the ability of the overall complex to recycle process water.

Water quality issues associated with coal storage and slag disposal will be addressed by using advanced control techniques. Storage and disposal areas will be situated to direct drainage away from critical wetlands and surface water bodies by capitalizing on topographic, sediment, and groundwater flow characteristics. Combining such natural features with engineered storage areas, subsurface drainage systems, physical barriers, and continual site monitoring programs will ensure the integrity of the region's water quality.

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No direct railroad access currently exists to the site. The existing Conrail line divides north of the site; one branch goes to Fall River passing approximately four (4) miles west of the site, while the other branch goes to New Bedford passing two (2) miles east of the site. A spur will have to be constructed to transport materials and coal to the site.

Legislation has been introduced in the State Legislature to provide an easement through the State Forest from the existing Conrail Newport line to the NEEP site.

7.4 NEEP SITE CHARACTERISTICS

7.4.1 Site Description

The New England Energy Park is located in the northeast corner of Fall River, Massachusetts, on a 1900-acre site formerly owned by Acushnet Sawmills. The 1900 acres are part of a 4500-acre property that EG&G has under a purchase and operation agreement. Small sections of the site extend into Freetown and Dartmouth. Because the site itself is part of an undeveloped 4500-acre property, it allows the nearby sparsely populated areas to be buffered by use of natural features.

The entire 4500-acre property is undeveloped and heavily wooded. The forest has been harvested for timber for more than 50 years; thus the trees are relatively young, mixed hardwoods with some pine stands scattered throughout. Several roads cross the site, but most are unpaved; significant portions of the site are accessible only by 4-wheel drive vehicles or on foot. There are few residential buildings near the site and none on it. The Freetown-Fall River State Forest is adjacent to the 4500-acre property.