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**OAK
RIDGE
NATIONAL
LABORATORY**

**UNION
CARBIDE**

**Cogeneration Feasibility Study
in the Gulf States
Utilities Service Area**

Work performed by the
Stone and Webster Engineering Corporation
Under Subcontract Number 7317
for
Oak Ridge National Laboratory

**OPERATED BY
UNION CARBIDE CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY**

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COGENERATION FEASIBILITY STUDY IN THE GULF STATES UTILITIES SERVICE AREA

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—Stone and Webster Engineering Corporation
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SECTION 1

EXECUTIVE SUMMARY

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SECTION 1

EXECUTIVE SUMMARY

1.1 INTRODUCTION

Stone & Webster Engineering Corporation was retained as a subcontractor by Union Carbide Corporation, Nuclear Division, to perform an extensive cogeneration feasibility study utilizing several alternative steam sources. The study was funded by the Energy Research and Development Administration (ERDA), which is now part of the Department of Energy (DOE). The study considers sites in the Gulf States Utilities (GSU) service area at Orange, Texas, and Geismar, Lake Charles, and North Baton Rouge, Louisiana. The sources of steam considered include oil, coal, high temperature gas-cooled nuclear reactor (HTGR) steamers, consolidated nuclear steam system (CNSS), atmospheric fluidized-bed coal combustion, and coal gasification.

A companion institutional study, which complements this engineering study, is being performed by Stone & Webster Management Consultants. Their report appears separately.

Concepts concerning cogeneration fuel systems were categorized by technical applicability as: current technology (pulverized coal-fired boilers and fuel oil-fired boilers), advanced technology under development (HTGR steamers and the CNSS), and advanced technology for future development (atmospheric fluidized-bed (AFB) boilers and coal gasification).

The fuel chargeable to power (FCP) in a cogeneration plant is on the order of half the heat rate of a fossil-fired power-only station. In addition to substantial net energy savings, the cogeneration alternatives studied would replace large amounts of scarce gas or oil with coal and nuclear fuel.

1.2 OBJECTIVES

In addition to providing data on cogeneration plants generally useful in the United States, the study determined the technical and economic feasibility of steam and electric power cogeneration using coal and nuclear fuels for localized industrial complexes. It also includes technical and economic studies associated with the atmospheric fluidized-bed boiler and coal gasification in conjunction with conventional gas-fired boilers, gas turbine combined cycle, and fuel cells. Such multicompany thermal grids should provide sufficient demand to make a large cogeneration plant attractive, both for lower capital investment and lower operating costs, when compared to a

program where each industrial plant would expand independently.

The scope of the study includes the tasks of selecting two sites most suitable for the cogeneration concept, developing and optimizing heat cycles, developing plant and equipment descriptions, determining capital and operating costs, evaluating alternatives, and presenting conclusions based on technical and economic factors.

1.3 SITE SELECTION

The siting objective of the study was achieved by comprehensively screening ten sites within the proposed four regions and applying specific siting parameters. Based on assigned "scores," sites at Orange, Texas, and Geismar, Louisiana, were selected as being the two best suited for both coal and nuclear cogeneration plants. This selection does not indicate that the other sites are not suitable, merely that they are less suitable to some degree.

1.4 HEAT CYCLE OPTIMIZATION

Utilizing heat balances and cost estimates, it was determined that economic benefits improved with higher steam operating pressures. Following the trend away from supercritical pressures, 2,400 psig was selected as the design operating pressure.

Maximum work is theoretically obtained with an infinite number of feedwater heaters. Final designs and heat balances generally include two closed feedwater heaters in series with the deaerator which balances capital costs against theoretical performance.

The most economic selection of turbine generators is the one that generates maximum power. In accordance with this criterion, straight noncondensing steam turbines were used where possible and practical. Extraction points increase turbine cost and reduce efficiency.

1.5 PLANT DESCRIPTIONS

All of the cogeneration plant designs were based on the total steam requirements projected for 1985 by the industrial users at the two specific sites. Generally, the proposed cogeneration plants at that time would have no excess capacity available for industrial expansion. The backup steam supply is assumed to be from users' facilities which must be maintained and expanded, as necessary, during construction of the cogeneration plant to provide, at a minimum, 100 percent of the users' backup requirements. Although the users at Orange required essentially four

operating pressures, steam from the cogeneration plant is distributed at two levels. The three distribution pressures at Geismar meet the three steam process pressures required by the users in that area. Projected 1985 steam demands are:

Process Steam Flows (lb/hr x 1,000)

	<u>970 psia</u>	<u>690 psia</u>	<u>640 psia</u>	<u>290 psia</u>	<u>Total</u>
Geismar	370	5,020	-	450	5,840
Orange	-	-	1,450	745	2,195

The equipment in conventional fossil-fired plants and nuclear plants is typical of power generating stations except for use of noncondensing turbines and the electrical and steam distribution systems. Generally speaking and where applicable, the plant arrangements include boiler feedwater heating and pumping, fuel handling, ash handling, precipitators and scrubbers, water and wastewater systems, and the necessary buildings and structures. The atmospheric fluidized-bed plant is similar except for the steam generator and limestone handling system.

Cogeneration plants employing coal gasification are more complex and contain a considerable amount of process equipment. Briefly, these plants include gasifiers, sulfur and ammonia removal equipment, tar-fired boilers, gas-fired boilers, air compressors, air separation equipment, ash handling, and waste gas treating systems. In addition, the basic systems are also required for coal handling, water and wastewater treatment, and the like.

At both Orange and Geismar, the fossil-fired plants are designed with two 50-percent capacity boilers. Choice of two boilers was made on the basis of minimum initial capital cost with reasonable operating flexibility.

The HTGR and CNSS plants are designed around intermediate sized nuclear units rated at 1200 MWt. Heat input requires two units in all cases except for the HTGR at Geismar where three units are necessary. Use of standard size units results in an excess steam generating capacity in all of the nuclear plants.

Unlike the CNSS, the HTGR is capable of generating process steam at the required pressure and temperature. Because of this, oil-fired superheaters must be used in conjunction with the CNSS. Also, the 970 psia steam required at Geismar must be generated in a conventional oil-fired boiler.

The following summary provides a general comparison of the various plant arrangements considered:

<u>ORANGE</u>	<u>Operating Pressure (psia)</u>	<u>Heat Input (MWt)</u>	<u>Net Electric Power (MWe)</u>
Eastern & Western Coals	2415	989.360	148.6
No. 6 Fuel Oil	2415	989.360	155.2
HTGR	2415	1007.363	164.6
CNSS without Condensing	640	871.083	23.8
CNSS with Condensing	640	1315.560	152.3
<u>GEISMAR</u>			
Eastern & Western Coals	2415	2630.958	352.2
No. 6 Fuel Oil	2415	2630.958	369.7
HTGR	2415	2684.883	400
CNSS without Condensing	690	2371.290	38.4
CNSS with Condensing	690	2872.295	183.2
Foster-Wheeler AFB	2415	2630.958	344.3
Babcock & Wilcox AFB	2415	2630.958	339.9
Coal Gasification with Conventional Boiler (Air-Blown)	2415	4791.7	474.7
Conventional Boiler (Oxygen-Blown)	2415	4867.6	476.7
Combined Cycle (Unlimited Elec.)	*	8161.1	1854
Combined Cycle (Limited Elec.)	*	4629.7	352
Fuel Cell (Unlimited Elec.)	*	10,989.0	2701.3
Fuel Cell (Limited Elec.)	*	4487.3	352

*970/690/290 psia.

1.6 CAPITAL COST ESTIMATES

Order of magnitude cost estimates were prepared for each type of cogeneration plant using vendor information and in-house costing data. Costs covered the complete plants outlined and described in Section 4. Land and right-of-way costs, licensing, environmental impact studies, relocation of existing facilities, and dismantling costs at the end of the useful plant life were excluded. No allowance is made for related equipment and construction costs required by users in their plants to utilize the steam and electric power. A summary of the capital costs is shown in Table 1-1.

Estimates are for costs as of January 1978 escalated through 60 percent of the construction period. Interest during construction was calculated at simple interest for the final 40 percent of construction. Cost estimates and related analyses for the advanced technology concepts categorized as future development were prepared for the Geismar site only.

1.7 ECONOMIC ANALYSIS

The economic comparisons outlined in Section 1.7.1 below have been made utilizing levelized steam costs based on utility-type fixed charges that provide a nominal rate of return of 10 percent. All of the net operating costs were developed using the same construction starting dates. In addition to having different initial operating dates caused by varying construction requirements, the anticipated operating life of the plants were 30 years for all of the fossil-fired plants versus 35 years for nuclear plants.

Since the possibility for ownership by an entity other than a utility does exist, an expense center cost analysis was made for discount rates of 10, 15, and 20 percent and fuel costs varying from 90 to 200 percent of the best estimate. Also, the discounted cash flows were determined based on all plants having the same startup date by delaying construction where applicable. A summary of the discounted cash flow analysis is covered in Section 1.7.2.

1.7.1 Economic Comparisons

Because steam is the primary product of the subject cogeneration plants, the final economic evaluations are based on the net operating cost per thousand pounds of process steam. This figure was determined from the annual operating cost comprising fixed charges (taxes, insurance, and debt service), operating and maintenance costs, and fuel costs, with a credit allowed for the net electric power exported. Total yearly process steam is based on maximum projected demand for 7,884 hours.

Except for the fixed charges, the annual operating costs and the credit for electric power are escalated to the service date of each particular plant and levelized for projected plant life. The costs per thousand pounds of process steam in levelized dollars are summarized in Table 1-2.

As shown by the table, eastern coal is the least expensive of the current technology concepts in terms of process steam costs but only slightly less than western coal. Within the advanced nuclear technologies considered to be under development, the HTGR is far better economically than the CNSS. Atmospheric fluidized-bed combustion is the economic choice within future development concepts. Considering all three categories, the HTGR provides steam considerably lower in cost than any of the other schemes. Other factors aside, it emerges as the best economic choice among technologies. The addition of condensing capabilities in the CNSS plants reduces steam cost by 28 percent at Orange and 12 percent at Geismar.

1.7.2 Discounted Cash Flow Analysis

The expense center cost analysis determined the present value of the net cash outflow, discounted to 1979, for each of the proposed cogeneration plants, taking into account the cash requirements for capital investment, fuel storage capacity, fuel costs, operating and maintenance costs, credit for in-plant electric power generation, credit for taxes and depreciation. For comparison, the present value of operating expenses for continued operation of existing facilities was calculated. Values were calculated for three discount rates and four fuel costs for both Orange and Geismar.

The resulting present values have been utilized to develop the costs per thousand pounds of steam, which are a more meaningful and understandable basis for an economic evaluation. The following steam costs are summarized in Table 1-3 for a 10 percent discount rate and 100 percent fuel costs.

(1) Minimum Revenue Requirement (MRR) Steam Costs

These steam costs provide the minimum rate of return of 10 percent used as the basis to determine results in Tables 6-4 and 6-5. However, steam costs have been recalculated based on the longest construction period and a plant operating life of 30 years. The total study period is 37 years in all cases to agree with the DCF analysis.

(2) Levelized Steam Costs After Taxes

These steam costs were derived using results of the DCF study and the appropriate discount rate and plant life.

(3) DCF Break-Even Purchase Prices

These are the prices that could be paid to purchase steam to give the same levelized after-tax costs described in (2) above.

Tables 6-17 and 6-18 can be used to compare steam costs for other assumed values for the rate of return and fuel costs. It can be seen that at a 10 percent discount rate, the HTGR provides the lowest steam cost, and eastern coal is second. The same results occur as did in Tables 6-4 and 6-5 with western coal, the CNSS and No. 6 fuel oil following in that order.

The order is essentially the same at a discount rate of 15 percent, except at fuel costs of 90 and 100 percent where the HTGR loses most or all of its advantage over eastern coal.

At a 20 percent discount rate, eastern and western coal steam costs are lowest with the other alternate plants changing in order of costs depending on the fuel costs assumed.

The CNSS, at a fuel cost of 90 percent, is competitive with eastern coal plants at fuel costs from 150 to 200 percent, depending on the discount rate.

The study does point out that a definite economic advantage exists for an industrial user to purchase steam from an entity having a rate of return limited by regulation.

Although steam costs levelized over a 30-year period beginning in 1986 are good for comparison of alternates, they are difficult to relate to and compare with present day costs. Table 6-20 contains present day steam costs based on the DCF study for all of the alternates at two different escalation rates and the three discount rates. For a general comparison in this section, Table 1-4 shows the present value steam costs for a 10 percent rate of return and a 7 percent escalation rate.

All of these are below the 1979 operating costs for the existing plants. This advantage disappears as the discount rate increases to 20 percent.

TABLE 1-1

SUMMARY OF ESTIMATED CAPITAL COSTS
(\$ x 1,000)

Type of Cogeneration Plant	Orange, Texas		Geismar, Louisiana	
	January 1978 Dollars	Including Escalation and Interest During Construction	January 1978 Dollars	Including Escalation and Interest During Construction
Eastern Coal Fired	292,620	485,738	715,491	1,184,368
Western Coal Fired	294,993	489,677	717,514	1,191,045
No. 6 Fuel Oil Fired	247,286	382,255	636,172	983,394
HTGR	410,000	729,787	1,127,000	2,006,025
CNSS (Without condensing)	380,800	677,812	844,700	1,503,539
CNSS (With condensing)	424,200	755,062	888,900	1,582,214
Foster-Wheeler AFB			626,202	1,309,471
Babcock & Wilcox AFB			751,828	1,248,005
Coal Gasification With				
Conventional Boilers (Air-Blown)			1,297,086	2,153,113
Conventional Boilers (Oxygen-Blown)			1,473,439	2,445,853
Combined Cycle (Unlimited Elec.)			2,976,000	4,940,046
Combined Cycle (Limited Elec.)			1,600,000	2,655,939
Fuel Cell (Unlimited Elec.)			2,797,230	4,643,295
Fuel Cell (Limited Elec.)			1,179,100	1,957,260

TABLE 1-2

COST OF COGENERATION PLANT PROCESS STEAM
(Levelized \$/1000 lb)

<u>Current Technology</u>	<u>Orange</u>	<u>Geismar</u>
Eastern Coal-Fired	6.19	6.39
Western Coal-Fired	6.69	6.88
No. 6 Fuel Oil-Fired	10.76	11.17
<u>Advanced Technology - Under Development</u>		
HTGR	3.45	4.25
CNSS without Condensing	9.86	10.00
CNSS with Condensing	7.10	8.80
<u>Advanced Technology - Future Development</u>		
Foster-Wheeler AFB		5.84
Babcock & Wilcox AFB		6.62
Coal Gasification with:		
Conventional Boilers (Air-Blown)		13.13
Conventional Boilers (Oxygen-Blown)		14.42
Combined Cycle (Unlimited Elec.)		14.56
Combined Cycle (Limited Elec.)		16.48
Fuel Cell (Unlimited Elec.)		9.91
Fuel Cell (Limited Elec.)		13.46

1.8 RELIABILITY - FOSSIL FUEL AND NUCLEAR PLANTS

A reliability study using availability factors extracted from published data indicates that spare steam generating equipment can be economically justified for certain concepts. Justification was determined by comparing the annual fixed charges attributable to the increased capital cost for the purchase and installation of additional equipment with the resulting savings in fuel costs. Steam capacity not generated in the cogeneration plant due to the unavailability of steam generating equipment was assumed to be generated by the users' backup boilers burning No. 2 fuel oil. The improvement in availability with the addition of spare or backup equipment reduced the users' operating time and thus reduced the overall operating costs. Variations in credit for electric power generated by the cogeneration plant are also a factor affecting the total operating costs and were considered.

At Geismar, spare steam generating equipment is justified for both coal-fired plants and the CNSS, while the HTGR provides only a marginal return on investment. A spare boiler for the 970 psia process steam required to supplement the CNSS cannot be justified.

At Orange, spare units were found to be only marginally warranted for both coal-fired plants. Spare nuclear steam generators cannot be economically justified.

1.9 PROVISIONS FOR CONDENSING CAPABILITIES

Economic analyses have shown that the use of excess steam generating capacity (that above process steam requirements) to increase electric power generation justifies installation of the additional equipment needed to incorporate a condensing turbine generator. The HTGR and CNSS plants have inherent excess capacity due to standard size increments of steam generators and would require only the suitable steam turbine generator and the related condensing and cooling water equipment.

Since the CNSS is a viable option, a detailed analysis using condensing facilities was made which confirmed that the added capital costs were more than justified by the credit received for the resulting increase in power generation. Although the steam costs were not reduced enough to compete with the coal-fired plants, they are more attractive when comparing costs with an oil-fired cogeneration plant or continued operations of the present facilities.

Spare steam generating capacity or redundant capacity in any type cogeneration plant warrants an investigation of the costs associated with the addition of condensing facilities. Generally, it appears that additional equipment is justified provided demand for electric power is flexible.

1.10 EFFECT OF PLANT SIZE AND PROCESS STEAM REQUIREMENTS

Comparison of the steam costs indicates that plant size, based on the steam generated, has no effect on the economic selection of the type of cogeneration plant. Even though Orange is half the size of Geismar, the advantages and disadvantages of each type of plant are similar. The same order of preference exists for both sites. At both sites, the eastern coal-fired plant proves to be the best choice under current technology and the HTGR is the better choice under advanced technology.

Net costs per thousand pounds of process steam are not lower for the larger plant at Geismar because plant size is not the governing factor. Before credit for power, the larger plant has the lower operating costs. This result is expected and indicates that utilization of the steam has an impact on net costs. At Geismar, higher process steam requirements reduce energy utilization and thus reduce the electric output per unit of process steam.

1.11 SEQUENTIAL CONSTRUCTION OF PLANTS

The option of installing two or three nuclear steam generators at 5-year intervals in the HTGR and CNSS plants was investigated and found economically unattractive. Installation of the required capacity during the initial construction provides lower total operating costs over the life of the plant.

An alternative that would only install two HTGRs initially and omit the third unit totally yielded lower operating cost for a short period of time. When considering the full life of the plant, the base option with three HTGRs still provided the least total cost in present worth dollars.

1.12 GENERAL CONCLUSIONS

All of the economic comparisons were made assuming nth-of-a-kind plants for the alternatives investigated. In addition, the final conclusions and recommendations have taken into consideration technical factors and present state of the art. The results of this study are site specific but may be common for other locations; however, a general application cannot be assumed valid and should be avoided. Each potential cogeneration site must be evaluated on its own merits for specific steam and electric power requirements.

The coal-fired cogeneration plant is recommended to meet the immediate needs of an industrial complex based on both economics and current technology. Such a plant can be built now with confidence because the technology has been well developed and performance can be predicted with a high degree of accuracy. Also, use of coal agrees favorably with the present national energy program emphasizing utilization of U.S. coal reserves.

Eastern coal emerged as the economic choice with the cost of process steam marginally less than that of western coal. Basically, this is the result of the selection of assumptions. For this reason, a detailed review should be undertaken for any contemplated cogeneration plant. To achieve maximum flexibility and ensure against uncertainties in fuel supplies, it is recommended that a coal-fired plant be designed to accommodate both types of coal. Flue gas scrubbers should be designed to handle the high sulfur eastern coals. The boilers and all their related auxiliaries and coal and ash handling facilities should be sized to utilize the lower Btu western coals.

Scrubbers have been included in the fossil-fired plants to meet the updated New Source Performance Standards (NSPS) which call for "full scrubbing." The scrubber equipment is

a significant part of the estimated capital costs with the investment varying from 14 percent for eastern coal to 16 percent for oil-fired plants. The operating and maintenance costs for scrubbers amount to about 25 percent of the total for western coal and about 40 percent for the oil and eastern coal-fired plants.

The HTGR, which is categorized as an advanced technology under development, provides the lowest process steam cost but because of limited successful operating experience in the United States cannot be considered as an immediate candidate plant.

All of the concepts considered to be advanced technology, future development, were defined, costed, and economically compared; but none can be seriously considered for application in cogeneration plants at this time.

An atmospheric fluidized-bed boiler used to generate steam results in net process steam costs similar to those of pulverized coal-fired plants when considering designs and cost data of two manufacturers. Present ongoing development anticipates commercial operation of large-scale utility plants by the end of the century. Continued development of the AFB is recommended because it offers the potential for utilizing vast low-grade coal resources in an environmentally acceptable manner.

The coal gasification process was considered as the fuel gas source for three plant configurations, all of which generate process steam at a higher unit cost than pulverized coal-fired plants. This conclusion is due to the overall lower thermal efficiency, high initial capital costs, and high operating and maintenance costs. While coal gasifiers represent commercial or near commercial technology, developmental work presently in progress should yield an improved and reliable process within the next 10 years.

One concept studied utilizes the production of coal gas from either an air-blown or oxygen-blown gasifier in a cogeneration plant with conventional gas-fired boilers. Both alternates result in steam costs of approximately twice that of a pulverized coal plant and therefore are not competitive with coal firing and limestone flue gas scrubbing.

The use of the gas turbine combined cycle in conjunction with a coal gasifier is not suited for the cogeneration plants studied. This is true because utilization of all the coal gas from the coal gasification plant in the combined cycle system to generate required process steam results in the generation of a great quantity of electric power (about five times that of the standard coal-fired plant). To limit

electric power output requires the addition of gas-fired boilers to generate steam while limiting electric power and reducing fuel input. Steam costs for both cases are extremely high.

Fuel cells used in conjunction with coal gasification are similar to the combined cycle with regards to high electric power generation and, within the constraints of the present study, will not fit the requirements for a cogeneration plant with process steam as the prime commodity. Limiting electric output requires the addition of coal gas-fired boilers to generate the required process steam. Steam costs are slightly lower than the combined cycle plant but still considered high.

1.13 IMPLEMENTATION

Engineering and construction of the recommended coal-fired cogeneration plant can start immediately, and it can be in commercial operation in 6 years. There are no technical constraints to deter progress. If the project becomes a reality, the initial engineering phase should begin with a detailed economic evaluation to determine the number and size of boilers to obtain optimum reliability. Also, consideration should be given to the merits of including condensing capabilities to increase electric power generation. This may hinge entirely on plant ownership and the ability of the owner or owners to use or sell the resulting additional power.

At Geismar, during the construction of the cogeneration plant, the users must maintain and expand their steam generating facilities to meet their projected demands. This will automatically provide 100 percent backup to the cogeneration plant and ensure continuity of operations. Projected steam demands at Orange indicate expansion of users' facilities is unnecessary. Like Geismar, they must maintain their steam generating facilities through the construction period of the cogeneration plant, thus providing 100 percent backup for the cogeneration plant.

Since the HTGR can provide the required process steam and the fuel costs are low, it is economically attractive. However, based on experience to date, the HTGR has not progressed technically to a point to be considered a viable option for a cogeneration plant. Technical acceptance may be 10 to 20 years away. Development of the HTGR for utility use may eventually produce a reactor suitable for industrial cogeneration.

For the two applications in this study, the CNSS does not meet the specific steam requirements of the cogeneration plants without the addition of reboilers, superheaters, and

a fossil-fired boiler at Geismar. This additional equipment increases operating costs and makes it economically unattractive as a candidate plant. Nothing further is recommended for use of a CNSS at Orange or Geismar. It should not be assumed, however, that the CNSS is unsuitable for other potential cogeneration sites. The CNSS may be applicable and more attractive for cogeneration plants providing heating steam for hospital, residential, and commercial areas. Some industrial complexes may also have needs within the limits of the CNSS.

Atmospheric fluidized-bed boilers, with the capability of burning low-grade coals in an environmentally acceptable manner, offer potential benefits. Ongoing development efforts appear to be adequate and should continue.

Coal gasification is not specifically suited to meet the basic parameters of the plants studied and no development work can be justified on that basis. However, there appears to be a potential, when used with the gas turbine combined cycle or the fuel cell, for applications requiring high electrical output. Because of this potential, studies scheduled and in progress should continue.

1.14 ENERGY SAVINGS

Cogeneration, in this site-specific study, results in global energy savings for all current technology classified plants. Similarly, the nuclear plants also yield a reduction in total energy input. Energy savings, which are based on a comparison with existing operations, result from improved operating efficiency and the lower heat rate chargeable to cogenerated electric power. Only the AFB provides an energy savings among the cogeneration plants considered as advanced technology, future development. The net energy savings, or loss, per operating hour for the various cogeneration options are:

Energy Savings (Loss) -Btu x 10⁶/hr

<u>Cogeneration Plant</u>	<u>Orange</u>	<u>Geismar</u>
Coal-Fired	1246.2	3284.6
Oil-Fired	1334.7	3471.6
HTGR	1923.4	5073.0
CNSS	820.2	2001.1
Foster-Wheeler AFB		3426.2
Babcock & Wilcox AFB		3133.8
Coal Gasification with		
Conventional Boiler (Air-Blown)		(1319.5)
Conventional Boiler (Oxygen-Blown)		(1561.2)
Combined Cycle (Limited Elec.)		(2077.6)
Fuel Cell (Limited Elec.)		(1591.5)

The use of coal or a nuclear fuel as the energy source would replace about 3,603 million Btus per hour of oil or gas used by the industrial facilities at Orange. This is equivalent to 25,000 gph of oil. At Geismar, an alternate fuel would replace 9,963 million Btus per hour (equivalent to 70,000 gph of oil). The reduction of oil would be less for the CNSS by 3,200 gph and 9,800 gph at Orange and Geismar, respectively, because of the use of oil to fire the superheaters and boiler required in the plant system.

TABLE 1-3

COMPARISON OF STEAM COSTS⁽¹⁾

	MRR Steam Costs (\$/1000 Lb)	LSC After Taxes Based on the DCF (\$/1000 Lb)	DCF Break-Even ⁽³⁾ Purchase Price (\$/1000 Lb)
<hr/>			
<u>Orange</u>			
Eastern Coal	6.55	3.62	6.70
Western Coal	7.06	3.91	7.24
No. 6 Fuel Oil	12.28	6.84	12.67
HTGR	3.33	2.05	3.80
CNSS	9.29	5.14	9.51
Existing Plants ⁽²⁾	-	8.25	15.28
<u>Geismar</u>			
Eastern Coal	6.76	3.41	6.56
Western Coal	7.27	3.68	7.08
No. 6 Fuel Oil	12.75	6.63	12.75
HTGR	4.07	2.05	3.94
CNSS	9.40	4.76	9.15
Existing Plants ⁽²⁾	-	6.72	12.92

⁽¹⁾ Levelized for 30 years starting in 1986⁽²⁾ Operating costs only⁽³⁾ Income Tax rate 46 percent at Orange; 48 percent at Geismar.

TABLE 1-4

PRESENT VALUE STEAM COSTS NET-OF-TAXES⁽¹⁾

(1979 \$/1000 LB)

	<u>Orange</u>	<u>Geismar</u>
Eastern Coal	1.13	1.06
Western Coal	1.22	1.15
No. 6 Fuel Oil	2.14	2.07
HTGR	0.64	0.64
CNSS	1.61	1.49
Existing Plants ⁽²⁾	2.73	2.73

⁽¹⁾ Based on 7 percent escalation rate and 10 percent discount rate.

⁽²⁾ Operating costs only for No. 2 fuel oil.

INTRODUCTION

INTRODUCTION

AMERICAN CHEMICAL SOCIETY
11 Dupont Circle, N.W.
Washington, D.C. 20036

SECTION 2

INTRODUCTION

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Figure 2-1 Location of the Four Proposed Regions

SECTION 2

INTRODUCTION

The study described in this report was undertaken by Stone & Webster Engineering Corporation (S&W) under subcontract to the Oak Ridge National Laboratory operated by Union Carbide Corporation. Economic and engineering factors were considered by S&W to evaluate the feasibility of the development in the 1980's of a cogeneration plant in the Gulf States Utilities (GSU) service area. This section of the report briefly indicates the scope of the work carried out by S&W and the approach taken.

2.1 OBJECTIVES AND SCOPE

The objectives of the cogeneration study were to determine:

- Technical and economic feasibility of steam and electric power cogeneration alternatives using coal and nuclear fuels for industrial plants located in the general area of Gulf States Utilities.
- Technical and economic data on cogeneration plants generally useful in the United States.
- Technical and economic feasibility of steam and electric power cogeneration using atmospheric fluidized-bed boilers.
- Technical and economic feasibility of steam and electric cogeneration utilizing gasified coal in conventional boilers, fuel cells, and gas turbines.

This report considers current and advanced technology steam and electric generating configurations for application at two locations determined to have the best potential for utilization of the cogeneration concept. The projected 1985 industrial steam and electric loads for the two locations were used as the basis for determining the capacity of the proposed plants.

The following current technology alternatives were considered for each of the two selected sites:

- Low-sulfur western coal with conventional boilers and stack-gas desulfurization system.
- High-sulfur eastern coal with conventional boilers and stack-gas desulfurization system.

No. 6 oil-fired boilers, with precipitator and stack-gas desulfurization systems, were also considered for reference and comparison.

Alternatives categorized as advanced technologies under development were also considered for both sites:

- Consolidated nuclear steam supply (400 MWe) as proposed by Babcock & Wilcox Company.
- High-temperature gas reactor (400 MWe) as proposed by General Atomic Company.

In addition, the following advanced technology schemes, considered as future developments, were developed for only one selected site:

- Eastern coal atmospheric fluidized-bed boilers.
- Eastern coal gasification utilizing conventional boilers, gas turbines with waste heat boilers, and fuel cells.

The following investigations were made to achieve the study objectives:

1. For the Geismar, Lake Charles, North Baton Rouge, Louisiana; and Orange, Texas regions, the two sites best suited for a coal and/or nuclear cogeneration plant were determined considering the following constraints:
 - Air pollution standards
 - Availability of cooling water
 - Ability of alternatives to meet siting constraints.

Figure 2-1 shows the general location of the four proposed regions.

2. Steam and electrical requirements were determined for the industrial users at the two selected sites.
3. Heat cycles were developed for each cogeneration plant optimizing steam pressure, feedwater heating, and electric power generation.
4. Capital and operating cost estimates were prepared to permit economic comparison of the net operating cost for each alternate. Analysis was based on

escalated and levelized costs for the projected life of the individual plants.

5. Applicability of the atmospheric fluidized-bed boiler to cogeneration plants was determined, utilizing eastern coal and considering present-day technology, availability of equipment, and costs.
6. Applicability of the coal gasification concept to cogeneration was determined, utilizing eastern coal and present-day technology. Coal gas generated in the coal gasification plant would be used to produce steam and generate electricity by:
 - Direct combustion of the gas in conventional boilers with electric power generation from noncondensing steam turbine generators.
 - Gas turbine generator electric power generation with waste heat boiler steam generation.
 - Fuel cell electric power generation with waste heat boiler steam generation.
7. Reliability of steam-generating equipment was determined for the various arrangements and economic justification for backup.
8. Construction schedules were prepared for possible implementation of the current technology alternatives using coal and the advanced technology alternatives incorporating the HTGR and CNSS.

Section 2.2 describes the methodology used by S&W to perform each of these tasks.

2.2 METHODOLOGY

The general approach taken to achieve study objectives included:

- Developing basic economic and technical criteria
- Selecting two candidate sites
- Preparing heat balances and diagrams
- Developing plant description and cost estimates
- Analyzing results
- Presenting conclusions and recommendations.

The first requirement of the study was to define economic input needed to determine the capital and operating costs for the various cogeneration plant concepts. The assumptions for capital costs, fuel costs, operating and maintenance costs, rates of return, escalation factors, etc., were derived from various sources and approval obtained from the parties involved.

Because of the different operating dates established for the plants, the use of levelized costs for the life of the plants is an appropriate method of economic comparison. Factors for determining levelized cost are projected plant life, rate of return, and inflation rate.

Concurrently, while developing the economic assumptions, the four suggested plant sites were investigated and evaluated using weighted siting parameters to determine the two sites best suited for a cogeneration plant. Once sites were selected, the steam and electric requirements for the two selected sites were developed to establish plant design parameters. The steam flows projected by the industrial users for 1985 were used as the required capacity for each of the plants. Although the sites presently use steam at four and five different operating pressures, distribution from the cogeneration plants was established at a maximum of three pressure levels to minimize the size of the distribution system. Further control of steam pressures was left to the responsibility of each user.

Utilizing preliminary cost estimates, heat cycles were optimized for operating pressure and feedwater heating. Based on results of this optimization, heat balances were developed for all of the concepts considered as current technology and advanced technology under development; i.e., fossil fuel-fired plants and nuclear plants. The heat balances are basic and do not include consideration of pressure drops, heat losses, leakage, and blowdown. For the purpose of this study, comparative data are required and more detailed heat cycle analysis is not necessary.

Steam generating equipment, water treatment, turbine generators, structures, and other major plant equipment were investigated and developed for both fossil fuel and nuclear plants. General descriptions for each type of plant at each site were then prepared. Plot plans were also prepared to show site locations and the diagrammatic routing of the steam distribution piping and electric power.

Similarly, atmospheric fluidized-bed and six coal gasification schemes, considered as advanced technology (future development) were developed and described with

supporting drawings and diagrams. Information from published reports was utilized where possible in the preparation of this report and referenced accordingly.

Utilizing heat cycles, descriptions, and published data, an order-of-magnitude capital cost estimate was prepared for each site configuration. Costs for fuel, operation, and maintenance were calculated using the appropriate economic factors and heat input data. Operating costs were also developed for the users' facilities to permit comparisons with the cogeneration plant and for input when studying the various modes of operation.

This costing data was used to develop the annual operating costs taking into account the credit received for exported electric power. Net operating costs in levelized dollars per thousand pounds of process steam, assuming the maximum steam flow for 7,884 hours per year, were used to make direct comparisons.

Economic analyses made on the basis of Nth-of-a-kind plants were made within each category of technology, and the best results of each then compared to arrive at the best overall economic choice. Further analysis of other factors impacting the type of plant best suited for cogeneration within an industrial complex, now and in the future, determined final recommendations concerning plant type.

Other factors having possible impact on the implementation of this study were also investigated. The factors considered were:

- Size of plant with respect to costs
- Sequential installation of steam generators
- Provisions for condensing capabilities
- Reliability.

Backup data and conclusions were included, and engineering and construction schedules developed for coal-fired and nuclear plants.

After reaching conclusions, recommendations and implementation strategies were presented for the various concepts.

The information and data contained in the remainder of this report are presented in a logical sequence, each section being independent of the previous section. That is, for each site and/or topic, the sections are complete within themselves and can be read without reference to other

sections. This procedure presents some duplication of material but is necessary to permit continuity in review and study of the data. It also enables individuals to concentrate their efforts in areas of specific interest. The process developed to evaluate suitable plant sites and the sites finally selected as candidate sites are described in Section 3.

FIGURE 2-1. LOCATION OF THE FOUR PROPOSED REGIONS

SECTION 3

SITE SELECTION

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SECTION 3

SITE SELECTION

3.1 INTRODUCTION

The objective of the siting portion of this study is to identify two candidate sites where a fossil-fueled or nuclear cogeneration plant may be located in the GSU service area. Information available from ERDA and GSU was employed in the site appraisal. When these sources could not provide sufficient information, Stone and Webster secured the required information from alternate sources. In accordance with the scope of work, no new siting data were developed from field studies.

The site selection process is designed to identify a number of realistic siting options. Four site regions consistent with the need for cogeneration were first designated by ERDA/GSU. A comprehensive screening process was then employed to identify those regions and sites that best fulfilled predetermined siting criteria. A reasonable balance of siting parameters was selected with special emphasis given to the unique considerations required for cogeneration plant siting. For example, realistic load demand distances and process steam/electric generation ratios were determined. Other important technical/engineering criteria such as water availability; highway, rail, and water access; proximity to hazardous materials; and land requirements were analyzed, as were a cross section of environmental/licensing and socioeconomic considerations.

Recommendation of selected sites does not foreclose the potential use of other closely ranked sites. Secondarily ranked sites are only less suitable when comparing all parameters in the siting study. Secondary sites may serve as a reserve for developing future energy production alternatives.

3.2 SITE SELECTION PROCEDURES

3.2.1 THE CANDIDATE REGION SCREENING PROCESS

Proximate location of the site to industrial steam users is a major constraint in locating a cogeneration plant. With regard to this requirement, the four site regions initially screened were geographically constrained to areas where steam demand either presently or potentially exists.

The siting procedure shown in Figure 3-1 is a progressive, iterative process of site region comparison and evaluation. The first phase of the siting procedure is designed to

FIGURE 3-1. MAJOR EVALUATIVE CRITERIA

identify the optimum candidate regions and preliminary sites within these regions for siting either a nuclear or fossil cogeneration plant. The second phase is a refined screening of the preliminary sites identified in the first phase. The third phase consists of detailed analyses and relative economic comparisons to select the final candidate plant sites. Each candidate region is comprehensively reviewed using an evaluative/exclusionary screening technique that includes licensing, environmental, socioeconomic, and technical/engineering considerations.

During Phase I, the basic geographical regions are defined, and specific evaluative/exclusionary screening criteria are applied to identify the candidate regions. A candidate region is one in which preliminary sites may be found. In order to screen candidate regions, specific technical/engineering and environmental/licensing criteria are applied to exclude or defer unsuitable land areas. Figure 3-1 conceptually illustrates the overall siting procedure; Figure 3-2 shows the approach taken in Phase I. Criteria used to screen a region of interest for nuclear and fossil facilities are also shown in Figure 3-2. Following this Phase I screening, remaining candidate areas are further evaluated in Phase II.

As indicated in Figure 3-2, exclusionary criteria principally associated with nuclear facility safety-related issues include considerations such as geology/seismology, demography, and proximity to hazardous facilities. Both nuclear and fossil facilities' exclusionary criteria include incompatible land use; i.e., proximity to national forests, major wetlands, and wildlife refuges. These criteria are considered exclusionary because they define areas that can be eliminated from further consideration. Deferral criteria, on the other hand, can be applied to identify areas of technical/engineering or environmental/licensing suitability; i.e., land or water availability. Areas unable to support the required type and size facility are deferred for possible use in siting an advanced cogeneration plant.

Coincident with identification of the candidate regions in Phase I, the preliminary sites within the candidate regions are also determined for further screening and analysis in Phases II and III.

3.2.2 SITE SELECTION SCREENING PROCESS

The preliminary sites identified in Phase I are further analyzed in Phase II by applying detailed evaluative criteria consisting of technical/engineering considerations, physical and environmental/licensing considerations, and socioeconomic considerations. A complete breakdown of these criteria evaluated on the basis of difficulty/qualitative cost/acceptability is contained in Table 3-1.

FIGURE 3-2. SELECTION OF CANDIDATE REGIONS

TABLE 3-1

MAJOR EVALUATIVE CRITERIA

Technical/Engineering Considerations

Site Preparation - Considerations such as excavation, dewatering during construction, site grading, berms, and drainage.

Proximity to Load Demand - Maximum and average distance to process steam/electric power users.

Water Availability - Maximum, average, and minimum stream flow.

Highway, Railroad, and Water Access - Availability of each mode for fuel and waste transportation.

Foundations - Existing stratigraphy and the effects of seismology of the area, location of groundwater, soil improvement, and pile or caisson requirements. The liquefaction phenomenon is also considered for nuclear plant siting.

Water Supply Systems - Construction requirements for circulating and service water systems.

Land Costs - Qualitative land cost comparison of all sites.

Steam Supply/Demand Match - Relationship between the available power plant steam supply systems and steam demand requirements.

Physical and Environmental/Licensing Considerations

Wastewater Impact - Environmental impact of blowdown, cooling tower effluent, or other wastewater discharges.

Cooling Water Impact - Effect of consumptive water use, percentage of minimum stream flow.

Land Use - Present utilization of the site area and adjacent land (i.e., commercial, industrial, state preserve, etc.).

Land Requirements - Amount of available land for plant construction, operation, fuel storage, and transmission/steam lines.

Geology - Structural geology, geological history, seismology, subsidence.

TABLE 3-1 (Cont)

Hydrology - Flood probability, upstream water impoundments and feasibility of groundwater for consumptive use, groundwater contamination, drainage patterns.

Seismology - Basis for seismic design criteria.

Meteorology - Monthly average wind speed, wind direction, atmospheric stability, joint frequency, rainfall, storm severity, determination of area atmospheric diffusion.

Ecology and Croplands - Proximity to croplands, crop types, determination of unique or endangered ecological species, area ecology.

Radiological Considerations (Nuclear) - Determination of exclusion area, low population zone, and population center distance.

Air Quality Impact (Fossil) - Impact of gaseous effluent, area atmospheric diffusion, state and federal requirements.

Demography (Nuclear) - Current population of adjacent communities to 30 miles (50 miles if no town is within 30 miles), population density surrounding the site to 30 miles, population projections.

Noise Impact - Probable noise levels and impact on area industry and residences within 5 miles of the site.

Proximity to Hazardous Facilities (Nuclear) - Consideration of accidents at nearby industrial, military, and transportation facilities that may affect the safety of the plant.

Socioeconomic Considerations

Transportation - Impact of fuel and waste transportation on nearby communities and transportation corridors.

Community Impact - Effect of construction workers and their families on adjacent community housing, services, utilities, etc.

Archaeological and Historical Impact - Determination of areas on or near the site listed in the National Registry of Natural Landmarks and the National Registry of Historic Places.

Visual Impact - Assessment of the visual effects of the station and transmission/steam lines on nearby valued cultural, scenic, historic, park, and recreation areas.

TABLE 3-1 (Cont)

Transmission/Steam Line Impact - Assessment of the potential impact exposure will have on area ecology and communities.

The two major steps of Phase II are:

1. Site Identification - Evaluative/exclusionary criteria including technical, environmental/licensing, and socioeconomic considerations.
2. Site Comparison - Suitability/constraint criteria and matrix analysis.

Figure 3-3 illustrates the Phase II approach. The first step involves the application of further detailed evaluative/exclusionary criteria to the candidate areas described for Phase I. Some of the criteria shown on Table 3-1 are used as Phase II evaluative or comparison criteria and exclusionary or constraint criteria. Once defined, these criteria are analyzed and the resultant refined candidate areas are subjected to a matrix analysis. To perform a comparative analysis, a series of matrix weighting factors was developed to provide the appropriate impact of a specific siting criterion. These siting matrix weighting factors are discussed further in Section 3.5.1.

Technical/engineering and environmental/licensing requirements are integrated into the siting matrix. For example, in defining a technical/engineering parameter such as foundations, the following site-specific criteria would be explored: existing stratigraphy and seismology, location of groundwater, soil improvement, and pile or caisson requirements.

During Phase II, site development qualitative/cost considerations are initiated. Site-specific parameters are utilized to rank and select the best candidate sites for cost evaluation, site-specific environmental impacts, and socioeconomic assessment. The selection of candidate sites should therefore result in sites exhibiting maximum technical/engineering suitability and minimum overall environmental/licensing constraints. Preselecting candidate sites from a list of preliminary sites minimizes detailed site-specific Phase III investigations. The remaining potential sites can be placed in a site bank for future consideration.

The final selection of two plant sites from the list of candidates is similar to selecting candidate sites from preliminary sites in the site comparison stage of Phase II. Two major differences are the degree of detail and the integration of technical/engineering, environmental/licensing, qualitative, and cost considerations.

FIGURE 3-3. SELECTION OF CANDIDATE SITES

Some of the criteria compared on a cost basis include steam supply transmission cost, required steam demand, flood protection, foundations, site grading, hazard design (nuclear), land acquisition, and emission controls.

Factors which cannot be reasonably quantified or comparatively evaluated by site are ranked and weighted qualitatively by professional, experienced personnel. Some important nonmonetary factors include:

- General licensing issues and anticipated trends in regulations.
- Engineering factors with insufficient available data for definitive cost evaluation.
- Potential environmental impacts for which present data are insufficient to allow evaluation of cost control measures.
- Aesthetics.
- Institutional concerns.

More specifically, Phase III methodology includes the following:

- Preparation of a comparative (economic) site ranking for those engineering factors which will vary from site to site; e.g., site development, steam transmission, environmental controls, etc.
- Environmental and socioeconomic assessment for each candidate site. These assessments (non-monetary) are qualitatively transformed into a subjective ranking system using rating and weighting factors.
- Identification of environmental, socioeconomic, institutional, and political issues which are expected to have a significant impact on facility licensing for each site.

The use of a matrix analysis incorporating rating and weighting factors is applied. Nonmonetary considerations are transformed into a qualitative rating scale while weighting factors are established by the group consensus technique. Candidate plant sites can then be ranked in terms of qualitative/cost (QC) and suitability/constraint (SC) to establish whether a site with higher costs and SC scores is preferred over one with lower costs and SC scores.

Care is exercised to appropriately integrate applicable licensing issues during the ranking process.

3.2.2.1 Technical Engineering Considerations

3.2.2.1.1 Site Preparation

During the evaluation of the geographical regions and specific sites, assessment of site preparation includes:

- Existing topography relative to probable design flood levels.
- Extent of site clearing and grading required.
- Presence of drainage swales and/or ditches on property.
- Proximity to swampy terrain.
- Depth to groundwater table (of potential importance if a deep excavation should require dewatering).
- Excavation/backfill requirements.

Some of the factors delineated above are interrelated to other evaluation areas such as Foundations and Geology, inasmuch as these directly affect the extent of excavation and the amount of construction dewatering required.

Because site conditions vary, there is great variability in costs of site preparation. For example, when comparing costs of fossil plant design, considerations such as liquefaction (nuclear) and pile foundation (fossil) can make the costs of either higher and tend to equalize the assigned matrix weighting factors. A matrix weighting factor of 10 was assigned for site preparation of both fossil and nuclear plants.

3.2.2.1.2 Proximity to Load Demand

A primary consideration is the distribution of steam to potential users from the proposed cogeneration sites. It is assumed that the distribution of electric power will not change the ratings based on the distribution of steam.

The optimal size of the steam distribution pipes can be determined from an economic tradeoff between the capital cost of the installed pipe (which increases with pipe diameter) and the loss of electric power production because of fluid friction (which decreases with pipe diameter). Preliminary calculations indicate that distribution of steam is feasible up to a distance of 5 miles. Proposed sites

requiring steam distribution lines longer than 5 miles were rated zero under Proximity to Load Demand.

The importance of steam distribution in evaluating cogeneration plant sites warranted a matrix weighting of 25 points for both fossil and nuclear plants.

3.2.2.1.3 Water Availability

Power plants require water for condenser cooling and process purposes as well as for potable use. The water supply source must be reliable since the need for water is critical for efficient plant operation and safety. The sites were evaluated on the availability of water from the closest major source (river, stream, canal, etc.).

The water availability segment of the site evaluation is based on relative sources, flow rates, and quality. The minimum, average, and maximum flows available must be considered with respect to the maximum flow requirements of the station. One frequently used criterion is that water usage should not exceed 50 percent of the minimum flow for any year. The Nuclear Regulatory Commission (NRC) Regulatory Guidelines set 25 percent 10-day low flow over a 7-year period as the limiting factor.⁽¹⁾

The quality of the water must also be considered. It must be compatible with plant use so that excessive costs will not be incurred to improve the quality to usage standards.

NRC Regulatory Guide 1.27 requires that the heat sink of a nuclear plant serve two principal safety functions: (1) dissipation of residual heat after reactor shutdown and (2) dissipation of residual heat after an accident.⁽²⁾ The sink's capacity should be sufficient to provide cooling for the time required to evaluate the situation and take corrective action. A 30-day period is considered adequate for these purposes. Two sinks acceptable to the NRC include large rivers and large lakes.

As indicated in Section 3.2.2.1.8, the use of a condensing cycle was avoided; thus, circulating cooling water requirements are a slightly less critical siting constraint. A value of 20 was assigned as the weighting factor in the matrix. The consumption of cooling water for the service water system is of secondary importance when compared to power boiler makeup use. As indicated in Section 4.4.1.1.7, it is assumed that 50 percent of the steam generated will be returned for reuse in the form of condensate of unknown quality. Therefore, maximum consumption will be for makeup purposes. It is also assumed that geohydraulic conditions will not support the use of groundwater.

No limiting criteria have been set since the "offset" principle, that is, compensating principle, has been applied to each industrial complex. Since steam and water consumption requirements within each industrial area complex are presently being satisfied, the net steam and consequent water consumptions should be equal to or less than present consumption. Thus, no limiting criteria were applied.

3.2.2.1.4 Highway, Rail, and Water Access

Fossil and nuclear plant sites must be accessible to transportation; the reliability, ease, and cost of transportation affects the construction and operation of power plants. In addition to supplies, heavy equipment, and plant wastes, personnel must also be transported to the site. Rail, water, highway, and pipeline are the generally used transportation systems. Transportation to fossil sites is heavier in order to meet demanding fuel supply needs and, therefore, must be reliable.

Sites located near a navigable waterway may be conducive to barge loading and unloading. A navigable waterway is defined as any body of water, inland river, lake, canal, or other man-made or natural right-of-way with at least the following parameters: a mean low-water depth of not less than 6 feet, a minimum channel width of 50 feet, and a minimum clear vertical unobstructed height of 30 feet above mean-low-water.⁽³⁾

Each site was evaluated on its relative overall transportation corridor accessibility and/or the cost impact to ensure adequate access. Matrix weighting factors of 5 and 25 were assigned for nuclear and fossil plants, respectively.

3.2.2.1.5 Foundations

Primary consideration was given to the depth to firm bearing soil when evaluating foundation conditions in the regions. Fossil-fueled plants are likely to require pile or caisson foundations at all of the proposed sites. Alternatively, if the depth to firm bearing soil is not too great, consideration can be given to excavating the looser, soft soils and replacing them with well-compacted backfill. Economics and schedule considerations dictate the final choice.

The current state of the art in evaluating the potential loss of lateral support for pile foundations during earthquakes typically discourages using piles for nuclear power plant Category I structures. Interaction between piles and the surrounding soil under dynamic loads is an exceedingly complex, somewhat subjective analysis. Thus,

although pile foundations are technically feasible according to current NRC licensing positions, where loose or soft soils underlie a proposed commercial nuclear plant they are usually overexcavated and replaced with a well-compacted backfill.

Accordingly, when evaluating foundation conditions for nuclear plants in the proposed regions, consideration is given only to the amount of excavation and backfill that would be required to replace existing poor soil conditions. It must be emphasized that predicting foundation conditions at any of the proposed sites without the benefit of onsite soil borings may be speculative. Extrapolation of subsurface information from nearby soil borings can be misleading, particularly in areas where soils have been placed in their present locations by the geologic process of river deposition. A few of the proposed sites' subsurface foundation conditions were assessed using borings obtained several miles from the respective sites.

Liquefaction is a physical phenomenon that can occur in loose cohesionless silts and fine sands during large earthquakes. Soils that are susceptible to liquefaction lose their shear strength during large earthquakes and behave like a fluid. Obviously, structures founded on such soils would suffer massive damage. To preclude this, analyses are made to determine the susceptibility to liquefaction of soils at any proposed site. If it is determined that existing soils beneath a proposed site are susceptible to liquefaction, remedial measures such as densification or excavation and replacement with well-compacted soils must be undertaken.

Matrix weighting factors of 15 and 10 were assigned for nuclear and fossil plant foundations, respectively. This weighting was based on the cost impact of foundation support systems (i.e., compacted backfill or pile foundations) and the relative degree of difficulty in installing foundations.

3.2.2.1.6 Water Supply Systems

Construction requirements for transporting water to the station must be assessed in addition to assurance of an adequate water supply. Pumphouse construction, pipe sizes and routings, distances to potable water systems, etc., must be evaluated. For example, intake structures must be designed to prohibit fish from entering the system. Trash racks and traveling water screens may also be desired.

Each site was evaluated relative to known construction impediments and distance from water sources. Based on these criteria, a matrix weighting factor of 10 was assigned for both nuclear and fossil plants.

3.2.2.1.7 Land Costs

Imposing upon the total cost of a power plant is the cost of land. Generally, urban areas are more expensive than rural areas, and high-level ground is more expensive than low-lying or swampy ground. A matrix weighting factor of 5 for both nuclear and fossil plants was applied since land costs, while important, represent a small percentage of the total installed cost of a power plant. Individual sites were analyzed relative to present land use and future possibilities.

3.2.2.1.8 Steam Supply/Demand Match

A project management decision made at the outset of the study requires that no electric power generation be independent of steam produced for distribution. This precludes the use of steam turbine generators with condensers. Since steam demand in each region is such that the industrial community would be deficient in electric power and would have to import power from the GSU grid, the problem of matching steam supply and demand involves the availability of steam generators to produce the required steam.

The availability of coal-fired boilers in a wide range of sizes has prompted the relatively low steam supply/demand match matrix weighting of 10 for fossil plants. The match between supply and demand is more difficult for nuclear cogeneration plants and was given a weighting of 15. The proposed intermediate-size light water reactors (LWR) have thermal ratings of approximately 1000 to 1200 MW.

3.2.2.2 Physical, Environmental, and Licensing Considerations

3.2.2.2.1 Wastewater Impact

The environmental impact of service water cooling tower blowdown and other wastewater discharges must be considered so that effluent quality will be consistent with water quality standards. The most desirable areas from a water quality standpoint are sites which will not have an adverse impact on existing water quality.

While every effort will be made to close the water/wastewater cycle, the quality of return condensate from each industrial plant is indeterminate at this point. An accurate determination of wastewater quality should be made at a later date. It has been resolved that wastewater flows will be minimal (less than one percent of the water intake) and approximately the same quality for each site investigated. Accordingly, contributing factors in the

assessment of wastewater impact become the maximum, average, and minimum flows of the receiving body of water.

Due to the introduction of a larger quantity of wastewater from a fossil plant (coal pile runoff, ash transport water, etc.), wastewater impact is weighted more heavily. Liquid waste from either plant will meet all applicable regulatory agency requirements. A matrix weighting factor of 5 was assigned to a nuclear plant and 10 to a fossil plant.

3.2.2.2.2 Cooling Water Impact

As described in Sections 3.2.2.1.3 and 3.2.2.1.8, a design decision has precluded the use of power condensers; thus, condenser cooling water will not be required. However, NRC requires emergency cooling capabilities for nuclear plants. Emergency water use for a nuclear plant is about 120 cfs for each intermediate reactor. Since this water consumption occurs only under emergency conditions, the impact is of relatively minor importance; however, it has been recognized and must be assessed. The NRC requirement does not apply to fossil plants; hence, cooling water impact is not a consideration.

Where sources of cooling water are scarce or where other constraints exist, cooling ponds, reservoirs, or cooling towers for emergency cooling may be required. During emergency cooling, makeup water requirements are less than 5 cfs, a fraction of river flow. The combined effect of added costs, water consumption, and/or additional space requirements were assessed for each site under this category, and a matrix rating of 5 was assigned.

3.2.2.2.3 Land Use

In general, land areas suitable for power plant siting are areas that generate greater economic benefit if developed for power generation rather than for an alternate use. Preferred areas are vacant, not previously designated for use, and adjacent to industry.

The land use of an area selected for a power plant site must be compatible with surrounding and adjacent land use. This is determined by zoning regulations, official long-range municipal community plans for the area, and public opinion concerning the adequacy of the land for power producing purposes.

Exclusionary criteria applied to the candidate sites relate to their proximity to the following: (1) active military installations, (2) major commercial airports, (3) national and state parks and forests, (4) wildlife refuges, and (5) major wetlands.

A matrix weighting factor of 10 was applied for both nuclear and fossil plants.

3.2.2.2.4 Land Requirements

Land requirements pertain to the amount of land available for plant construction and operation. To determine the area required for a cogeneration plant, the following items must be taken into account: boiler (steam generator), turbine, fuel storage, fuel handling equipment, rail lines and/or barge unloading equipment, waste handling equipment, wastewater ponds, and switchyard, etc.

More land is required for the construction and operation of a fossil-fueled plant than for a nuclear-fueled plant. Therefore, the matrix weighting factor is higher for fossil- (25) than nuclear-fueled (20) plants.

The overall land requirement for constructing a nuclear unit is approximately 100 acres. This area is sufficient to accommodate switchyard, cooling tower, railroad sidings, and security fencing.

Siting two fossil units (coal- or oil-fired) would require approximately 300 acres. The area would accommodate fuel handling and storage, ash handling equipment, railroad sidings, wastewater handling equipment, switchyard, and security fencing. This estimate is based on land requirements not exceeding the following acreage: a 60-day fuel storage area of 20 acres, a sludge treatment area of 5 acres, a 5-acre switchyard, and a boiler plant complex of 20 acres.

3.2.2.2.5 Geology

Historical and structural geology directly affect the foundation requirements for siting nuclear and, to a lesser degree, fossil plants; indirectly they can alter the amount of site preparation required. Structural geology, as used herein, includes the broad consideration of tectonic structures that necessitate thorough evaluations for nuclear plant siting. Since the depth to bedrock exceeds several thousand feet at all four reviewed regions, any plant located within these regions would be founded on soil.

Knowledge of geologic origins and the age of deposition can play a significant role in the feasible siting of nuclear plants. The NRC is particularly concerned with geologic faults in close proximity to any nuclear site. When it has been determined that a fault (or other geologic feature) is within 5 miles of a proposed nuclear plant site, a study must be made to ascertain whether movements have occurred along the fault recently.^(4,5) At that time, the origin and

age of the deposition of soils overlying the faults can serve as tools in determining the geologic time that movement last occurred along the fault. The soil stratigraphy offsite as well as onsite may have to be studied using soil borings to determine whether the younger soils have suffered any displacements attributed to previous earthquakes along a fault in question.

The NRC defines an incapable fault as one which has not experienced either a single movement within the last 35,000 years or multiple movements within the last 500,000 years. Conversely, if studies indicate that movements within the 35,000- or 500,000-year criteria cannot be ruled out, a fault may be termed capable.^(4,5) It is then presumed that an earthquake could recur along the fault and thereby result in additional displacements in the near-surface soils.

In addition to the concern for nearby faults and their classification as capable or incapable, other geologic factors affecting power plant siting are subsidence and/or liquefaction. When large amounts of fluids such as oil and water are extracted from below proposed sites, the overall ground surface can subside, leading to concerns for flood potential and differential movements between buildings. Another cause of subsidence prevalent in the Gulf Coast region and the Mississippi River area is the downwarping of soil deposits caused by the ongoing process of soil deposition in the ocean and in river valleys. The vast amount of sediment carried by the Mississippi River is continuously deposited at its mouth. The additional weight of soils on existing deposits causes consolidation of the underlying layers and bending of deeply-buried strata. Due to constantly increasing overburden pressure tending to warp the underlying strata, slump faults are often formed trending in directions perpendicular to the axis of the river. Thus, slump faults trending generally east-west are abundant through southern Louisiana and Texas. Although these faults are not due to or capable of generating earthquakes, the NRC is concerned with their proximity to any proposed site inasmuch as they are definitive markers of potential differential subsidence and ground rupture.

Salt domes are common geologic structures throughout Louisiana and Texas.⁽⁶⁾ They are often flanked by petroleum deposits and are of special interest to the petroleum industry. Thus, the exploration and development of oil and gas is prevalent in the vicinity of an identified salt dome. Accordingly, the proximity of salt domes to the regions under consideration is significant because of their association with oil and gas withdrawal and the related concern for subsidence.

It is evident that nuclear site licensability is highly dependent on geologic considerations so a matrix weighting factor of 25 was assigned. Although a fossil plant's requirements are less restrictive, geology does affect related factors; i.e., foundation considerations. Therefore, a matrix weighting factor of 15 was assigned.

3.2.2.2.6 Hydrology

Hydrology criteria addressed include flood probability, upstream water impoundments, and drainage patterns. Areas located above the maximum recorded flood level are most desirable. Recently, an Executive Order on Floodplain Management⁽⁷⁾ directed all federal agencies to take measures to avoid, to the extent possible, the long- and short-term adverse effects associated with the occupancy and modification of floodplains and to avoid direct or indirect support of floodplain development where there is a practical alternative. Each agency was directed to provide leadership and to take action to reduce the risk of flood loss; to minimize the impact of floods on human safety, health and welfare; and to restore and preserve the natural and beneficial values served by floodplains.

Nuclear sites should be in compliance with Regulatory Guide 1.59.⁽⁸⁾ Sites located in floodplains may be difficult to license if construction of the facility results in alteration of the floodplain or drainage patterns. The consumption of groundwater has little impact on site evaluation since all water for consumption will be derived from rivers and streams. It is also expected that groundwater contamination will not be a factor since the facility is designed to preclude any possible contamination.

Drainage is a minimal factor in site evaluation. The flow of streams in candidate areas consists primarily of immediate and subsequent surface runoff during periods of precipitation. Sites will be graded to minimize local flooding due to poor drainage patterns. For these reasons, hydrology matrix weighting factors of 20 and 15 were assigned to nuclear and fossil plants, respectively.

3.2.2.2.7 Seismology

Seismology is assessed independently of Geology (Section 3.2.2.2.5) because of its importance in determining the seismic design basis for all plants. Fossil plant seismology is frequently treated by incorporating a seismic zone factor in the plant design criteria. This factor is usually delineated in a local building code and reflects the largest earthquakes experienced in the particular region.

Geologic or seismo-tectonic provinces are determined by studying the earthquake history and structural geology of a given area. Previous earthquakes are assumed to have occurred along a specific fault or within a specific seismo-tectonic province. The largest earthquake ever generated along that fault or within that geologic province is expected to be able to occur again within the design life of a nuclear plant. However, to provide additional margins of safety, the maximum recorded earthquake is assumed to recur along the fault or along the boundary of the seismo-tectonic province at its closest approach to the proposed site. Thus, previous earthquakes are postulated as recurring and generating the greatest intensity, acceleration, or other measure of damage potential at the proposed site.

The safe shutdown earthquake (SSE) is defined as the largest earthquake that could occur at the site. It represents the seismic motion the plant can undergo and retain the capability to be safely shutdown. The SSE is determined by examining the history of all earthquakes that have occurred and could conceivably recur at an epicentral location closer to the proposed site than the actual epicenter.

The NRC has established minimum values of horizontal acceleration due to an SSE. Currently, this minimum value of SSE horizontal acceleration is $0.10g$ where g is the acceleration of gravity. The prospective Louisiana/Texas regions lie within the confines of a relatively seismically inactive portion of the United States. Thus, it should be necessary to design any proposed nuclear plants only for the minimum SSE acceleration values allowed by the NRC.

For nuclear power plants, the operating basis earthquake (OBE) is determined as the largest earthquake expected to be felt at the proposed site during plant life.⁽⁵⁾ In many respects, the OBE corresponds to the design basis earthquake upon which building codes are based. Typically, the NRC stipulates that the OBE acceleration level must be at least equal to one-half the SSE acceleration.

Seismology also results in indirect plant construction costs. For example, as regional seismicity increases, foundations and equipment support members can increase in size to provide adequate margins of safety against failure during postulated earthquakes. Accordingly, seismic zone factors in building codes affect fossil plant costs, and SSE and OBE accelerations affect nuclear plant costs. Maximum weighting factors of 20 and 10 points were assigned for nuclear and fossil plants, respectively.

3.2.2.2.8 Meteorology

This section details the climatological features of the sites. Meteorological data include wind speed, wind direction, rainfall, storm severity and determination of area atmospheric diffusion. Atmospheric diffusion is defined as the ability of the atmosphere to disperse gases and particles emitted into the air. The diffusion is governed primarily by the motions of the atmosphere and the vertical temperature profile which are site-specific and depend, in part, on wind and topography.

The release rate of radioactive effluents from a nuclear plant can be designed to accommodate less than favorable dispersive qualities at a particular site. Therefore, exclusion criteria were not applied based on less than desirable meteorological or topographic conditions.

Preferred fossil plant sites exhibit adequate dispersive qualities allowing boiler stack emissions to have an insignificant impact at ground level.

Due to the proximity of candidate regions, the meteorological conditions are essentially the same, and the most important factor becomes the location of the site relative to prevailing wind direction and residential areas. For this reason, a matrix weighting factor of 15 for both nuclear and fossil plants was designated. (See also Air Quality Impact, Section 3.2.2.2.10.)

3.2.2.2.9 Ecology and Croplands

Desirable areas for power plants are those areas which do not support rare, endangered, or unique floral or faunal species, nor are they highly productive ecologic areas. They are distant from wildlife sanctuaries, refuges, or management areas, and do not support major populations of commercially valuable game birds or mammals. From the standpoint of terrestrial ecology, the most desirable area for locating a power generating facility is agricultural land under monoculture practices. Large, homogeneous tracts of cropland, in general, provide the minimum of habitat (food and cover) for wildlife species.

Desirable locations for a power plant, when concerned with aquatic or marine ecology, feature low marine life productivity and are distant from important spawning, nursery, or fishing grounds for commercial species of fish and shellfish. Similarly, areas which do not support rare or endangered species or important sport fisheries would be preferred.^(9,10,11)

No sites were excluded based on ecology and cropland factors; however, a detailed inventory and analysis should be conducted coincident with a site-specific preconstruction study. A matrix weighting factor of 10 was applied to both nuclear and fossil plants.

3.2.2.2.10 Air Quality Impact

The meteorology of candidate sites should exhibit adequate dispersive qualities so that boiler stack emissions have an insignificant impact at ground level. These sites should also be located where ambient air quality standards are not in danger of being violated.

As a result of a recent EPA interpretive ruling (December 21, 1976) for implementation of the requirements of 40 CFR 51.18 for preconstruction review of stationary air pollution sources, major new fossil-fueled facilities (which include power generating units) may not be constructed in nonattainment areas unless specific conditions are met.⁽¹²⁾ As a result of the imposition of this interpretation, a nonattainment status represents a constraint to the present siting of a new power facility. A solution is to obtain more than one-for-one legally enforceable emission reduction (offset) from existing sources in the area (whether or not under the same ownership) so as to represent reasonable progress toward achievement of the National Ambient Air Quality Standards.

On December 23, 1974, EPA promulgated the National Performance Standards for new stationary sources. As a new source the new power plant will comply with all performance standards covered in the latest issue of these regulations. These performance standards are listed in Table 3-2:

TABLE 3-2

EMISSION STANDARDS FOR NEW STATIONARY SOURCE

	<u>Lb/10⁶ Btu Heat Input*</u>
Sulfur Dioxide	1.20
Nitrogen Oxides	0.70
Suspended Particulate	0.10

*When solid fossil fuel is burned.

The Clean Air Act Amendments of 1977 specified Class I areas for prevention of significant deterioration (PSD). There are no Class I areas within 100 miles of the reviewed sites.

It is noted that all four candidate areas come under the jurisdiction of the Southern Louisiana/Southeastern Texas

Interstate Air Quality Control Region. All sites are within areas designated as nonattainment areas for photochemical oxidants (generally associated with hydrocarbons produced by petroleum refineries, petrochemical process plants, and oil burning power boilers). It is recognized that coal-fired power plants do not contribute to hydrocarbon levels and could conceivably reduce hydrocarbon levels by the "offset" principle. Air quality impact is not a consideration for nuclear licensing but must be heavily weighed for fossil plants. Accordingly, a matrix factor of 20 was assigned to fossil air quality impact.

3.2.2.2.11 Radiological Considerations

Light water reactor nuclear power plant licensing requires that there be assurance that dose limit guidelines of 10CFR100 will not be exceeded in the event of a design basis accident. The NRC has further specified lower dose limits in Regulatory Guides 1.3 and 1.4. The limit must be met at the construction permit stage to ensure that changes in the design or in meteorology do not result in calculated doses in excess of 10CFR100 guidelines.

A nuclear power plant, with a combination of engineered safety features to mitigate the consequences of an accident and located sufficiently distant from the population to allow for dispersion of radioactivity, must show that calculated doses are within predetermined limits.

The criteria used in this evaluation are based on distance from population concentrations. These requirements are either explicitly stated in 10CFR100 or based on past experience. The calculated doses will be determined when the plant design, including engineered safety features, is established and site specific meteorological data are available. The distances used in this evaluation are as follows:

Exclusion Area Boundary (EAB): Based on past experience, the NRC has found that a minimum distance to EAB for an LWR of approximately 3000 MWt is 0.4 miles.⁽¹³⁾ This assumes unfavorable design basis atmospheric dispersion characteristics and usually provides assurance that engineered safety features can be designed to bring the calculated dose from a postulated accident within the guidelines of 10CFR100. Stone & Webster's siting/licensing experience confirms the guideline distance of 0.4 miles. It should be noted that when siting a smaller power plant of approximately 1200 MWt the 0.4-mile guideline may not be applicable.

Low Population Zone (LPZ): The NRC guideline, which was based on past siting experience, indicates that a distance of 3 miles to the outer boundary of the LPZ is sufficient to provide 30-day doses within the guidelines of 10CFR100. Also, the NRC requires population density within the LPZ be limited to less than 500 people per square mile.

Population Center Distance: The distance from the outer boundary of the LPZ to the boundary of a population center of greater than 25,000 persons must be at least 1 1/3 greater than the distance to the LPZ outer boundary from the reactor.(14)

It should be noted that nuclear plants have been licensed for sites with EAB less than 0.4 miles or LPZ less than 3 miles, since it is the dose criterion that ultimately governs. Thus, a site is not absolutely precluded on the basis of distance alone. Due to the licensing requirements related to radiological considerations, a matrix weighting factor of 25 was assigned.

3.2.2.2.12 Demography

Areas of low population density are preferred for siting power plants, particularly a nuclear plant. High population densities projected for any period during the lifetime of a station are considered by the NRC and the public hearing phases of the licensing process. Should population densities at the proposed sites not be acceptably low, alternate sites might be needed to fulfill the regulatory requirements.

If the population density (including weighted transient population) projected at the time of initial operation of the plant exceeds 500 persons per square mile (averaged over a radial distance to 30 miles), alternate sites may be required to satisfy regulatory requirements. These requirements prevail if the projected population density over the lifetime of the plant exceeds 1,000 persons per square mile averaged over any radial distance out to 30 miles.(13)

The population density for a 5-mile and 30-mile radius from the site center was calculated by summing the present population of the towns within the radius and dividing the sum by the total area. Present population statistics were used since they are least restrictive and most documentable. Data will be gathered from federal and state census bureaus.

Those sites with a population density greater than 1,000 persons per square mile are excluded for nuclear plant considerations. Sites with a population density between 500 and 1,000 persons per square mile are constrained. Sites

with a population density less than 500 persons per square mile are acceptable (no constraint).

The impact of demographic considerations on the licensing process resulted in a matrix weighting factor of 25 for nuclear plants.

3.2.2.2.13 Noise Impact

The impact of noise from the power plant has to be assessed regarding its effect on the surrounding community.⁽¹⁾ The probable noise levels and impact on area industries and residences within 5 miles of the site were investigated. A nuclear plant without cooling tower has a minor noise impact. Fossil plants have a higher noise level due to outside coal handling equipment. It is expected that noise created by a fossil plant will represent a minor contribution to the ambient noise level due to the proximity of industrial complexes. Each site was evaluated with regard to its proximity to residential communities. A matrix weighting factor of 10 was assigned to fossil plants, a factor of 5 to nuclear plants.

3.2.2.2.14 Proximity to Hazardous Facilities and Activities

Potential accidents at nearby industrial, military, and transportation facilities may affect the safety of a nuclear plant. This factor is considered a siting constraint. For instance, the site under review should not be selected if, in the event of an accident, plant safety is significantly impacted, or if it is not possible for nearby facilities to alter their mode of operation to reduce the severity of these types of potential accidents.

In the event of an accident at a nearby industrial facility such as a chemical plant, refinery, gas, or petroleum processing and product storage installation, it is possible that missiles, shock waves, flammable vapor clouds, toxic chemicals, or incendiary fragments may result. This may directly affect the plant or plant operators and jeopardize plant safety.

An accident during the transport of hazardous materials (e.g., by waterway, railroad, highway, or pipeline) near a nuclear plant may generate shock waves, missiles, and toxic or corrosive gas that also can impact the safe operation of the plant. The consequences of hazardous accidents depend upon the proximity of the transportation vehicle or industrial facility, the nature and maximum quantity of the hazardous material, and the layout of the plant.

Generally, potentially hazardous facilities and activities within 5 miles of the proposed site are considerations. Stone & Webster has conducted detailed analyses on the potential impact of "hazardous accidents" and has successfully supported license applications for a number of nuclear power plants. Stone & Webster's experience in this area indicates that the plant can usually be designed so that its safety will not be affected by a hazardous accident, if the distances to these facilities and activities are no less than the following (based on a 3000-MWt nuclear power plant): 2,600 feet from railroad tracks; 1,800 feet from a major highway; 1,300 feet from a navigable river; 2,600 feet from gas or oil pipelines; and 2,600 feet from chlorine and other types of toxic chemical storage. Of course, specified site related analyses would have to be conducted to determine accurately the distances to hazardous materials, especially concerning shipment and storage of liquified material gas and railroad and highway accidents. Because of the relative importance of the siting criterion, a matrix weighting factor of 20 was assigned.

3.2.2.3 Socioeconomic Considerations

Socioeconomic issues are important determinants of siting policy. It is difficult both to assess the nature of the impacts involved and to determine value schemes for predicting the level or the acceptability of potential impacts.

The siting, construction, and operation of a power plant may have significant impact on the socioeconomic structure of a community and may place stress on the local labor supply, transportation facilities, and community services in general. There may be changes in the tax basis and in community expenditures.⁽¹⁴⁾ Problems may occur in determining equitable compensation for any required relocation of persons or facilities as a result of plant siting. Evaluation of the suitability of a site should, therefore, include consideration of these potential socioeconomic impacts.

In addition, certain communities in a site area may be subject to unusual impacts that would be costly to mitigate. For example, some towns have distinct cultural characteristics; i.e., places of historic interest, unusual industry, or unique archaeological or scenic characteristics that must be considered during the siting process.

3.2.2.3.1 Transportation

Transportation-related impacts occur during the construction and operation of a power plant. Movement of heavy equipment during construction could impact roads, underpasses,

bridges, etc., on land routes; and bridges, docks, etc., over water routes. During plant operation, the transportation requirements of a fossil plant involve large, continuous shipments of coal; nuclear plants involve radioactive fuel and waste shipment. Both construction and operation require adequate and available roads for transporting construction workers and employee commuting. Transportation considerations are less critical than other siting parameters and were assigned a matrix weighting factor of 5 for nuclear and 15 for fossil plants.

3.2.2.3.2 Community Impact

During construction and operation of the plant, workers and employees may affect nearby community infrastructures; e.g., additional housing requirements, utilities, police, fire, entertainment, and hospital facilities. Since the work force during construction and operation of the plant is expected to be a small percentage of the population of the adjacent communities, a matrix weighting factor of 10 was assigned.

3.2.2.3.3 Archaeological and Historical Impact

Areas valued for their historic and archaeological significance may be affected by siting a plant on or proximate to these areas. Those properties included in the National Registry of Historic Places that may be affected by the station, its associated facilities, and steam and electric transmission lines were reviewed. Potential archaeological sites in the plant site areas were confirmed. Mitigation or avoidance of historical and archaeological impact can be achieved. Therefore, a matrix weighting factor of 5 was assigned.

3.2.2.3.4 Visual Impact

Many visual and scenic detriments of the plant and its auxiliary facilities can be avoided or reduced by appropriate design and execution. Aesthetic impacts can also be mitigated by selecting sites where existing topography or environment, such as industry, effectively screen or ameliorate the presence of the station. Generally, the design of a nuclear plant is more aesthetically acceptable than a coal plant. Because the candidate sites are located in industrial areas, low matrix weighting factors of 5 and 10 were assigned for nuclear and fossil plants, respectively.

3.2.2.3.5 Transmission/Steam Line Impact

Transmission/steam line impact is an assessment of the potential effect that exposure of the lines (pipes) will have on area ecology and adjacent communities.

Transmission lines are generally run in the same corridor as steam lines with no cross connection to the area electrification grid. Cogeneration plants are assumed energy deficient, and a matrix weighting factor of 5 was assigned due to the assessment of limited impact.

The following section describes the characteristics of the four regions designated for evaluation of cogeneration plant location by ERDA(DOE)/GSU.

3.3 CHARACTERISTICS OF CANDIDATE REGIONS

3.3.1 NORTH BATON ROUGE REGION

The North Baton Rouge region comprises the area encompassing the City of Baton Rouge, Louisiana, and its contiguous suburbs. The region is located in south central Louisiana in the Mississippi River floodplain which consists of relatively low flatland. The population of Baton Rouge was 165,963 in 1970, is currently about 209,000, and is projected to reach 473,000 by 2020.

The humid subtropical climate of the region is influenced to a large degree by the proximity of the Gulf of Mexico. Prevailing southeasterly winds combined with warm air from the Gulf of Mexico provide mild, humid weather during most of the year. Throughout the year, the water modifies the relative humidity and temperature by decreasing the range between extremes. Relative humidities of less than 50 percent occur each month; however, they are less frequent in the summer than during the remainder of the year. Air from the interior occasionally brings drier and usually cooler weather, but air of continental origin generally influences the area very little during the summer, and only part of the time during other seasons.(15, 16)

The summer climate is warm and humid. Daily mean and maximum temperatures average 82 F and 92 F, respectively. Precipitation averages 5 inches per month. Afternoon thundershowers, which account for much of the rainfall, occur about one day in three during the summer months.

The winter climate is pleasant due to mild temperatures and moderate precipitation. Daily mean and maximum temperatures average 54 F and 64 F, respectively, and freezing temperatures occur on an average of one night in four.

3.3.2 LAKE CHARLES REGION

Lake Charles region is located on the east side of the City of Lake Charles and the Calcasieu River, which runs through the lake on its way to the Gulf of Mexico. The city is in the southwest corner of Louisiana, approximately 30 miles north of the Gulf of Mexico. Lake Charles had a 1970 population of 77,998 and a 2020 projected population of 116,500. Much of the Lake Charles terrain is level coastal plain. Most of the area to the south is marshland and bayous. Higher elevations around Lake Charles are cultivated with rice and soybeans. The remaining land is pasture and timberland.

The climate is humid subtropical. Prevailing winds are southerly 38 percent of the time, northerly 22 percent of the time, and easterly and westerly 40 percent of the time.⁽¹⁷⁾ Winds are rather light with 80 percent wind speed observations during the year recording 12 mph or less. The average minimum and maximum temperatures are 43 F and 91 F, respectively; annual mean temperature is 68 F. The average annual rainfall is 56 inches.

The Port of Lake Charles is a fully-equipped, general cargo, deep sea terminal and is one of the major rice shipping ports in the world. Due to deep sea transportation, mild climate, and numerous oil and natural gas wells, a large industrial complex has developed in the area.

3.3.3 ORANGE COUNTY REGION

The Orange County region is located on the Texas-Louisiana border in the extreme southeast corner of Texas, approximately 40 miles inland from the Gulf of Mexico. Much of the terrain is level coastal plain; the area to the south is prairie land whereas much of the area to the west is timberland. The climate of this region is semi-tropical. The population of Orange County is about 88,000 and is expected to reach 199,000 by 2020.

Orange is the crossroads for water transportation in that area. Ocean-going vessels and intracoastal barge lines operate from the Port of Orange.

Many chemical plants such as E.I. DuPont de Nemours & Company, Owens-Illinois, Phillips Petroleum, Allied Chemicals, Goodrich Chemicals, Gulf Chemicals, Firestone Petrochemicals, and Crown Zellerbach are located along what is known as "chemical row".

3.3.4 GEISMAR REGION

The Geismar region is located in south central Louisiana in the Mississippi River floodplain comprised of relatively low flatland. Geismar is a small village located on the Mississippi River approximately 16 miles southeast of Baton Rouge. Among the major companies located in Geismar are: BASF/Wyandotte, Monochem, Shell Chemical, Vulcan Chemical, Ciba-Geigy, and Allied Chemical.

The nearest population concentration is Gonzales, which had a 1970 population of 4,512 and a 2020 projected population of about 17,000.

The climate of the region is humid subtropical. The prevailing southeasterly winds combined with the moisture and warm air from the Gulf of Mexico provide mild, humid weather throughout most of the year.

The summer climate is warm and humid. Daily mean and maximum temperatures average 82 F and 92 F, respectively. Rainfall averages about 5 inches per month. Afternoon thundershowers, which account for most of the rainfall, occur on about one day out of three during the summer months.

The winter climate is pleasant due to mild temperatures and moderate precipitation. Daily mean and maximum temperatures average 54 F and 64 F, respectively, and freezing temperatures occur on the average of one night in four.

Using the methodology described in Section 3.2 for selecting specific sites, 11 possible locations within the four candidate regions were designated. The following section discusses their positions within the region and some of their relative merits. Section 3.5 is devoted to the in-depth analysis that ultimately defines the most desirable plant sites by weighted rank ordering.

3.4 LOCATION OF CANDIDATE SITES

3.4.1 NORTH BATON ROUGE SITES A AND B

Two potential plant sites were designated in the North Baton Rouge Region, within the boundaries of the City of Baton Rouge. Site A, the northern parcel, contains 220 acres; Site B, to the south, contains 30 acres. Because they are separated by a distance of only 8,400 feet, the sites were evaluated together.

As shown in Figure 3-4, both are bordered on the west by the Mississippi River, which qualifies as a navigable waterway

and handles considerable barge tonnage annually; ocean freight goes as far as the Baton Rouge Port to the north.

Plants at either site could be located approximately 600 feet from the river. Site A is presently a buffer zone between industrial complexes at the south and Southern University to the north. Site B is located in the middle of the industrial complex area.

Each site has easy access to all transportation means, is sufficiently near steam users, and has common environmental and engineering variables. The A/B sites are, however, collocated near an extreme bend in the Mississippi River, presenting hazards to river navigation and requiring further study of the suitability of the site for unloading fuel from barges.

3.4.2 LAKE CHARLES SITES A, B, AND C

The three Lake Charles sites, shown on Figure 3-5, are located in the southwest corner of Louisiana. Site A is approximately 5 miles from the City of Lake Charles, and about 10,000 feet from the Calcasieu River. This latter distance would require building additional channels, if barges were to be used for transporting fuel.

Because of the relatively flat terrain embanking the river, Site A and Site B, which are contiguous with the Calcasieu Ship Channel, might be prone to floods. Site C is some distance from the mainstream of the river and the channel and would not be subject to potential flooding.

FIGURE 3-4. NORTH BATON ROUGE SITES A AND B

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FIGURE 3-5. LAKE CHARLES SITES A, B, AND C

Site A, the smallest of the three sites at Lake Charles, contains 400 acres, sufficient for either fossil or nuclear plants. Steam customers are widely dispersed in this area; Site A is most closely located to a major portion of them. Because of its high elevation compared to Site B; proximity to railroads, interstate highways, the City of Maplewood; and industrial complexes and residential area, Site A's land is suitable for development and thus could be costly.

The 600-acre Site B, zoned industrial-commercial, is also located adjacent to an industrial complex. Its favorable access to the Calcasieu Ship Channel allows barge transportation of coal for a fossil plant; however, its lower elevation offsets the higher land costs that could exist because of its direct proximity. Cost also would be positively affected by Site B's greater distance from the Hollywood and Maplewood developed areas. In most engineering and environmental respects, Site B is similar to Site A, except that its lower elevation increases the likelihood of flooding.

Although Site C is also approximately 5 miles from the City of Lake Charles and 2 miles from nearby developed areas (i.e., Westlake), its 700-landlocked acres are nearly 7 miles from the Calcasieu River, preventing its sharing a number of features with the other two sites. Site C's chief water source is the Houston River, which is cleaner than the channel but unsuitable for barge unloading. Elevation is higher, flooding unlikely, and because of its remoteness from industry and residences, its desirability for land development is less. However, Site C's distance of 5 miles from major steam consumers presents a significant piping distribution problem.

3.4.3 ORANGE SITES A AND B

Two plant sites are located about 15 miles northeast of Port Arthur in the Orange County Region (see Figure 3-6). This region is part of the flat Texas coast that extends along the Gulf of Mexico. Both sites are adjacent to swampy terrain along the Sabine River, the border between Texas and Louisiana, and are connected with the Sabine by a network of canals. There is thus adequate water source for each site, but barge fuel transport does not seem economical.

The Gulf Intercoastal Waterway intercepts the Sabine River south of the Port of Orange, providing the port with a deep channel link to the Gulf. Other means of transportation are also accessible to the two sites.

Because steam consumers are clustered in a relatively small chemical industrial complex, the sites are located from 5,000 to 10,000 feet from customers. Site B is located within 8,000 feet of all steam users.

FIGURE 3-6. ORANGE COUNTY SITES A AND B

The two sites differ mainly in size, Site A containing approximately 300 acres, Site B 580 acres. Both are adequate for either type of cogeneration plant. Site B, however, is landlocked, thus inaccessible to water transport and requiring piping water at greater costs. Cost factors slightly favor Site B, however, because of its higher elevation; both sites are approximately 2 miles from the developed area of West Orange.

3.4.4 GEISMAR SITES A THROUGH D

Four locations for plants exist on relatively flat land dipping slightly away from the Mississippi River in the Geismar region. All would require overexcavation and replacement with well-compacted backfill for nuclear plants.

Sites A, B, and D contain wooded and grazing lands; Site C is cleared. As shown in Figure 3-7, Sites A to D, located from north to south, are all fronted by the Mississippi River which offers each source of water and water transport. Rail and principal highways link the sites to the Baton Rouge area 16 miles to the northwest. Sites A, C, and D are collocated with a major industrial complex; nearby population centers are Gonzales and Donaldsonville.

Site A is located near a major river bend creating problems for barge traffic. Furthermore, because of its 64-acre size, which will not support either type of plant, Site A was eliminated from further consideration at this time.

Site B, the largest site in the Geismar Region is approximately 600 acres, lying north of the industrial complex. Its distance to steam consumers varies between 5,000 and 22,000 feet. A second advantage is Site B's lower position on the river, making it possible to utilize existing dock facilities for fuel unloading.

All steam users lie within 10,000 feet of Geismar Site C, which consists of 500 acres suitable for either plant. Its closeness to the Belle Helene Plantation presents historical and visual interference problems. Site D lies south of all steam customers with distances from 8,000 to 18,000 feet. Its narrow configuration and limited size (100 acres) makes it unsuitable for current state-of-the-art nuclear or fossil plants.

As seen from this discussion, even preliminary definition of potential sites indicates criteria which could preclude present serious consideration of some sites. Further screening is achieved by employing the Phase II procedures described in Section 3.2.2. The next section explains the development of the site comparison matrix in detail.

3.5 SITING CRITERIA

3.5.1 SITING MATRIX WEIGHTING FACTORS

As mentioned in Section 3.2.2, a method was developed to provide the appropriate impact of specific siting criteria during the site comparison process (see Figure 3-1). Each siting consideration was assigned a numerical value that was proportional to its burden on plant engineering, licensing, and environmental impact. This numerical value was designated as the matrix weighting factor.

The numerical variance assigned permits a realistic comparison of each of the elements of the siting study. It also provides an integrated method of comparing the proportionate value of any one siting element related to a nuclear plant site versus a fossil plant site. For example, demographic considerations in nuclear siting are more critical from a licensability standpoint than wastewater considerations. The rationale behind this assumption is based on the significantly higher cost to increase engineered safeguards for calculated radiation doses to population versus the cost to comply with water pollution regulatory standards.

In addition, strict regulatory criteria have been promulgated for demographic totals and population density that, if exceeded, could completely exclude a site. Consequently, a matrix weighting factor of 25 was assigned in considering demography, whereas a matrix weighting factor of 5 was assigned to wastewater impact.

Similar reasoning prevails for the identical matrix weighting factor regarding the nuclear plant site versus the fossil plant site. For example, the consideration of highway, rail, and water access is significantly more important for a fossil plant site than a nuclear plant site. The impact of continuous large shipments of coal compared to the periodic small shipments of uranium fuel presents a substantially more sensitive effect on the siting concerns. Therefore, a matrix weighting factor of 25 was assigned to fossil and 5 to nuclear plants.

Consistent with the above description, each of the siting elements was analyzed for its proportional impact on the siting process, and matrix weighting factors were assigned.

3.5.2 SITING CRITERIA LIMITS

A quantitative ranking system was devised to compare all potential nuclear and fossil plant sites. The numerical values, called matrix ratings, assigned to the individual siting considerations were developed based on

suitability/constraint criteria. This system consists of five basic headings with corresponding numerical ranges. Each siting consideration was reviewed and specific criteria established for each of the headings. For example, the headings and numerical ranges of demography are:

<u>Heading</u>	<u>Numerical Range</u>
Constraint	0
Less Constraint	1-15
No Constraint	16-19
Suitable	20-23
Very Suitable	24-25

The following demographic criteria were utilized to screen primary and candidate sites for a nuclear plant:⁽¹⁸⁾

<u>Matrix Rating</u>	<u>Demographic Criteria</u>
0	Sites with a present population density greater than 1,000 persons per square mile for a 5-mile radius or 500 persons per square mile for a 30-mile radius.
1-15	Sites with a present population density greater than 500 persons per square mile for a 5-mile radius or less than 500 persons per square mile for a 30-mile radius.
16-19	Sites with a present population density less than 500 persons per square mile for a 5- or 30-mile radius.
20-23	Sites with a present population density less than 300 persons per square mile for a 30-mile radius.
24-25	Sites with a present population density less than 150 persons per square mile for a 30-mile radius.

As indicated above, each consideration for the sites was assigned a matrix rating. Then matrix ratings were totaled for the three major siting categories (technical/engineering, physical, environmental/licensing, and socioeconomic). Finally, a combined total score for each site was obtained by summing the resulting three categories and a relative site ranking was derived.

Table 3-3, Site Selection Matrix - Nuclear Plant Site and Fossil Plant Site, summarizes the matrix ratings for each

site in the three major siting categories. The lengthy step-by-step analytic process from which these ratings were derived is provided for reference in Appendix A. Application of Siting Criteria to Candidate Sites. The respective ranking of the sites is discussed next.

3.6 CANDIDATE SITE EVALUATIONS

3.6.1 SITE RANKING

The cumulative weighting factor for nuclear plant sites is 340, including technical/engineering scores of 105, physical/licensing scores of 205, and socioeconomic totals of 30 points. Fossil fuel combined score is 300 with technical, physical, and social considerations totaling 115, 140, and 145, respectively.

Ranking the 10 designated sites by high score for both nuclear and fossil sites provides the following order:

<u>Nuclear Plant Sites</u>	<u>Technical/ Engineering</u>	<u>Physical/ Environ- mental</u>	<u>Socio- economic</u>	<u>Total</u>
1. Geismar B	81	177	30	288
2. Geismar C	86	170	28	284
3. Orange B	90	162	30	282
4. Orange A	84	162	30	276
5. Lake Charles C	56	175	28	259
6. Geismar A	72	154	30	256
7. Lake Charles B	64	154	28	246
8. Geismar D	71	154	25	250
9. Lake Charles B	64	154	28	246
10. North Baton Rouge A/B	91	128	26	245

Fossil Fuel Plant Sites

1. Orange B	97	134	42	273
2. Geismar B	101	126	44	271
3. Geismar C	104	126	40	270
4. Orange A	91	124	42	257
5. Lake Charles B	78	121	43	242
6. North Baton Rouge A/B	105	99	37	241
7. Lake Charles A	83	115	42	240
8. Lake Charles C	62	124	41	227
9. Geismar A	77	101	44	222
10. Geismar D	89	97	36	222

TABLE 3-3
SITE SELECTION MATRIX - NUCLEAR PLANT SITE

DESIGNATED SITE	TECHNICAL/ENGINEERING CONSIDERATIONS								TOTAL SCORE - TECHNICAL/ENGINEERING	PHYSICAL AND ENVIRONMENTAL/ LICENSING CONSIDERATIONS												TOTAL SCORE - PHYSICAL/ENVIRONMENTAL	SOCIOECONOMIC CONSIDERATIONS					TOTAL SCORE - SOCIOECONOMIC	COMBINED TOTAL SCORE	RANK	
	SITE PREPARATION	PROXIMITY TO LOAD DEMAND	WATER AVAILABILITY	HIGHWAY, RAIL, AND WATER ACCESS	FOUNDATIONS	WATER SUPPLY SYSTEMS	LAND COSTS	STEAM SUPPLY/DEMAND MATCH		WASTEWATER IMPACT	COOLING WATER IMPACT	LAND USE	LAND REQUIREMENTS	GEOLOGY	HYDROLOGY	SEISMOLOGY	METEOROLOGY	ECOLOGY AND CROPLANDS	RADIOLOGICAL CONSIDERATIONS (NUCLEAR)	DEMOGRAPHY	NOISE IMPACT		PROXIMITY TO HAZARDOUS FACILITIES	TRANSPORTATION	COMMUNITY IMPACT	ARCHAEOLOGICAL AND HISTORICAL IMPACT	VISUAL IMPACT				TRANSMISSION LINE IMPACT
MATRIX WEIGHTING FACTOR	10	25	20	5	15	10	5	15	105	5	5	10	20	25	20	20	15	10	25	25	5	20	205	5	10	5	5	5	30	340	
NORTH BATON ROUGE - A/B	7	25	20	5	12	10	2	10	91	5	5	6	20	20	20	20	11	10	5	0	4	2	128	5	6	5	5	5	26	245	10
LAKE CHARLES - A	7	20	10	5	8	6	3	10	89	3	3	8	20	15	20	20	9	10	10	19	4	15	156	5	8	5	5	5	28	253	7
LAKE CHARLES - B	7	15	10	5	8	6	3	10	84	3	3	8	20	15	16	20	11	10	10	19	4	15	154	5	8	5	5	5	28	246	9
LAKE CHARLES - C	10	0	7	5	12	7	5	10	56	3	3	10	20	17	20	20	3	10	20	19	4	20	175	5	8	5	5	5	28	259	5
ORANGE - A	7	20	15	5	11	8	3	15	84	4	4	10	20	15	20	17	15	10	10	20	5	12	162	5	10	5	5	5	30	276	4
ORANGE - B	7	25	15	5	11	7	5	15	90	4	4	10	20	15	20	17	15	10	10	20	5	12	162	5	10	5	5	5	30	282	3
GEISMAR - A	5	10	20	5	8	8	4	12	72	5	5	9	1	15	16	20	12	8	25	25	5	8	154	5	10	5	5	5	30	256	6
GEISMAR - B	5	20	20	5	8	8	3	12	81	5	5	9	20	15	16	20	12	8	25	25	5	12	177	5	10	5	5	5	30	288	1
GEISMAR - C	5	25	20	5	8	8	3	12	86	5	5	9	20	15	16	20	12	8	25	25	5	5	170	5	10	4	4	5	28	284	2
GEISMAR - D	5	10	20	5	8	8	3	12	71	5	5	6	2	15	16	20	12	8	25	25	5	10	154	5	10	2	3	5	25	250	8

TABLE 3-3 (CONT'D)
SITE SELECTION MATRIX - FOSSIL PLANT SITE

DESIGNATED SITE	TECHNICAL/ENGINEERING CONSIDERATIONS								TOTAL SCORE - TECHNICAL/ENGINEERING	PHYSICAL AND ENVIRONMENTAL / LICENSING CONSIDERATIONS										TOTAL SCORE - PHYSICAL/ENVIRONMENTAL	SOCIOECONOMIC CONSIDERATIONS					TOTAL SCORE SOCIOECONOMIC	COMBINED TOTAL SCORE	RANK
	SITE PREPARATION	PROXIMITY TO LOAD DEMAND	WATER AVAILABILITY	HIGHWAY, RAIL, AND WATER ACCESS	FOUNDATIONS	WATER SUPPLY SYSTEMS	LAND COSTS	STEAM SUPPLY/DEMAND MATCH		WASTEWATER IMPACT	LAND USE	LAND REQUIREMENTS	GEOLOGY	HYDROLOGY	SEISMOLOGY	METEOROLOGY	ECOLOGY AND CROPLANDS	AIR QUALITY IMPACT	NOISE IMPACT		TRANSPORTATION	COMMUNITY IMPACT	ARCHAEOLOGICAL AND HISTORICAL IMPACT	VISUAL IMPACT	TRANSMISSION LINE IMPACT			
MATRIX WEIGHTING FACTOR	10	25	20	25	10	10	5	10	115	10	10	25	15	15	10	15	10	20	10	140	15	10	5	10	5	45	300	
NORTH BATON ROUGE - A/B	8	25	20	20	10	10	2	10	105	10	6	6	10	15	10	11	10	16	5	99	15	8	5	4	5	37	241	6
LAKE CHARLES - A	7	20	10	20	7	6	3	10	83	6	8	22	14	15	10	9	10	16	5	115	15	9	5	8	5	42	240	7
LAKE CHARLES - B	7	15	10	20	7	6	3	10	78	6	8	25	14	13	10	11	10	16	8	121	15	9	5	9	5	43	242	5
LAKE CHARLES - C	10	0	7	15	8	7	5	10	62	6	10	25	15	15	10	9	10	16	8	124	12	9	5	10	5	41	227	8
ORANGE - A	7	20	15	20	8	8	3	10	91	9	10	15	12	15	10	15	10	18	0	124	13	10	5	9	5	42	257	4
ORANGE - B	7	25	15	20	8	7	5	10	97	9	10	25	12	15	10	15	10	18	0	134	13	10	5	9	5	42	273	1
GEISMAR - A	8	10	20	10	7	8	4	10	77	10	9	0	12	12	10	12	8	18	0	101	15	10	5	9	5	44	222	9
GEISMAR - B	8	22	20	23	7	8	3	10	101	10	9	25	12	12	10	12	8	18	0	126	15	10	5	9	5	44	271	2
GEISMAR - C	8	25	20	23	7	8	3	10	104	10	9	25	12	12	10	12	8	18	0	126	15	10	4	6	5	40	270	3
GEISMAR - D	8	10	20	23	7	8	3	10	89	10	5	0	12	12	10	12	8	18	0	97	15	10	2	4	5	36	222	9

Geismar B is one of the two highest in each site category. Orange B ranks first as a fossil fuel plant site and third as a nuclear site; Geismar C ranks second as a nuclear and third as a fossil-fuel plant site. In our analysis, the first/third combination would slightly favor the Orange B site but could not be considered decisive. A further rationale used to arrive at only two sites suitable for both plants is explained in the following section.

3.6.2 SELECTION OF TWO SITES

Combining scores in the two plant categories presents the following rank:

	<u>Technical/ Engineering</u>	<u>Physical/ Environ- mental</u>	<u>Socio- economic</u>	<u>Total</u>
1. Geismar B	182	303	74	559
2. Geismar C	190	296	68	554
3. Orange B	187	296	72	555

Geismar B remains first in combined score, followed by Orange B, with Geismar C being third. A difference of one point is hardly significant, since technical and physical considerations can often be compensated for by innovative design or cost trade-offs. However, Geismar C's closeness to the historic Belle Helene Plantation presents social factors not controllable by design engineering, and makes Orange Site B with its marginal one point difference the more desirable of the two sites for both types of plants.

Thus, the analysis has pinpointed Geismar Site B and Orange Site B as the two preferred candidates for the erection of either a nuclear or fossil fuel cogeneration plant.

Section 4 describes alternative fossil fuel (i.e., oil- and coal-fired), nuclear (consolidated nuclear steam system and high temperature gas-cooled reactor steamer), and advanced technology (fluidized-bed boiler, coal gasification, and combined cycle gas turbine) plants that could feasibly be built on the selected sites.

PLANT DESCRIPTION

SECTION 4

PLANT DESCRIPTIONS

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SECTION 4

PLANT DESCRIPTIONS

This section provides a general description of the cogeneration plants and the major systems and equipment reviewed and costed in this study. Site arrangement drawings and fundamental flow diagrams are included in Appendix B for further clarification.

4.1 PROJECTED USERS' DEMANDS

4.1.1 ORANGE REGION

4.1.1.1 Steam Requirements

The total requirements for steam projected for consumers in the Orange region are shown in Table 4-1:

TABLE 4-1

STEAM REQUIREMENTS - MM LB/HR

	<u>T</u>	<u>F</u>	<u>F</u>	<u>H</u>	<u>E</u>	
Pressure, psig	600	450	100	220	430	
<u>Temperature, F</u>	<u>761</u>	<u>600</u>	<u>350</u>	<u>440</u>	<u>580</u>	<u>Total</u>
1980	1.0	.18	.045	.53	.27	2.025
1985	1.0	.18	.045	.70	.27*	2.195
1990	1.0	.18	.045	.80	.27*	2.295

*Projected steam usage not available, initial demand held constant.

4.1.1.2 Electrical Requirements

The total electrical requirements projected for consumers in the Orange region are shown in Table 4-2:

TABLE 4-2

ELECTRICAL REQUIREMENTS - MW

<u>Year</u>	<u>T</u>	<u>F</u>	<u>H</u>	<u>E</u>	<u>Total</u>
1980	88	54	20	35.5	197.5
1985	90	54	26	NA	205.5
1990	95	54	30	NA	214.5

4.1.1.3 Backup Steam Source

The cogeneration plants (fossil and nuclear) at Orange, Texas, are designed to meet the steam demand projected to 1985 of Firestone, Gulf Chemical, B.F. Goodrich, and DuPont, with no reserve capacity. Reserve and backup capacity would be the responsibility of each user. It has been assumed that up until the commercial operating date of the cogeneration plant, each user will continue to maintain and expand, if necessary, its steam-generating facilities to meet process needs. On this basis, in 1985 the steam-generating capacity contained in each user's plant will provide a minimum of 100-percent backup. This assumption appreciably reduces the initial capital investment (particularly for the nuclear units), assures users of process steam under all circumstances, allows sufficient time to debug the cogeneration plant without loss of productivity, and permits time for the cogeneration plant to gain the confidence of the industrial users.

The projected steam requirements for this site indicate minimal expansion after 1985. From the standpoint of reliability and present fuel and equipment costs, a third coal-fired boiler can be marginally justified but a nuclear steam generator for the CNSS and HTGR cannot. It is recommended that fuel and equipment costs for the addition of backup equipment be reviewed at the conception of cogeneration plant planning.

Users' plant expansions and increases in steam requirements beyond 1985 should be reviewed yearly to determine the steam-generating facilities that would be the most economical, reliable, and flexible. Factors such as timing of future expansions, fuel costs, cost of maintaining users' steam-generating facilities and process downtime costs should all be considered. At each review, the inclusion of the backup steam-generating capacity should be evaluated with the projected steam requirements.

4.1.2 GEISMAR REGION

4.1.2.1 Steam Requirements

The total requirements for steam projected for consumers in the Geismar region are shown in Table 4-3:

TABLE 4-3

STEAM REQUIREMENTS - MM LB/HR

	E	L	H	H	N	
Pressure, psig	640	650	640	950	250	
Temperature, F	740	740	740	850	NA	Total
1981	1.76	.75	.90	.37*	.36	4.14
1982	2.035	.77	.95	.37	.37	4.495
1983	2.22	.775	1.05	.37	.43	4.85
1984	2.22	1.0	1.15	.37	.44	5.18
1985	2.32	1.5	1.2	.37	.45	5.84
1986	2.32	1.6	1.25	.37	.46	6.0
1987	2.35	1.7	1.3	.37	.47	6.19
1988	2.38	1.8	1.35	.37	.48	6.38
1989	2.44	1.9	1.45	.37	.49	6.65
1990	2.5	2.0	1.55	.37	.5	6.92

*Projected steam usage not available, initial demand held constant.

4.1.2.2 Electrical Requirements

The present (1978) electrical requirements for the consumers in the Geismar region are shown in Table 4-4:

TABLE 4-4

ELECTRICAL REQUIREMENTS (1978) - MW

E	L	H	N	Total
150	16*	96	78	340

*Will soon be increased to 24 MW.

Projections indicate more than a 50 percent increase in electrical power consumption by 1985.

4.1.2.3 Backup Steam Source

The cogeneration plants at Geismar, Louisiana, are designed to meet the steam demands projected to 1985 of BASF, Shell, Vulcan, and Monochem with no reserve capacity. Reserve or backup capacity would be the responsibility of each user. It has been assumed that up until the commercial operating date of the cogeneration plant, each user will continue to maintain and expand its present steam-generating facilities to meet process demands. A comparison of the present-day installed steam-generating capacity to the projected steam demands indicates that three of the users must add

facilities in the 1979-1981 time period. On this basis, in 1985, the steam-generating capacity contained in each user's plant will provide a minimum of 100-percent backup. This assumption appreciably reduces the initial capital investment (particularly for the nuclear units), assures users of process steam under all circumstances, allows sufficient time to debug the cogeneration plant without loss of productivity, and permits time for the cogeneration concept to gain the confidence of the industrial users.

Although each plant scheme has been optimized on the basis of providing 100 percent of 1985 users' requirements, a reliability analysis indicates that a third 50-percent capacity steam generator, for backup, could possibly be justified for the coal-fired plants and the CNSS. A spare for the HTGR plant would be marginal (see Section 6.3). On the basis of this analysis, it is recommended that when plans to construct a cogeneration plant are being developed, the economics of an additional steam generator be evaluated to determine the most economical, reliable, and flexible plant configuration. Timing of future expansions, fuel costs, operating and maintenance costs, size and condition of users' steam generation facilities, and cost attributable to process downtime are the major factors that should be considered.

Users' projected steam requirements should be reviewed yearly to determine future needs. At each review, consideration should be given to incorporating backup steam-generating capacity in future expansion of the cogeneration plant. Inclusion of backup capacity in plant expansions may be economically justified by the retirement of old boilers in the users' plants.

4.2 HEAT CYCLE OPTIMIZATION - ORANGE AND GEISMAR SITES

4.2.1 STEAM PRESSURE DETERMINATION

Industrial cogeneration plants have historically operated with steam turbine inlet pressures of 1,450 or lower psig. Figure 4-1 shows the relationship between throttle pressure, exhaust pressure, and kWh per 1,000 pounds of steam, indicating that electric generation can be increased by as much as 40 percent by increasing the steam throttle pressure from 1,450 to 2,400 psig for a number of exhaust pressures. The 2400-psig pressure is typical of current utilities practice. Pressures higher than current industrial practice, which yield maximum kWh per 1,000 pounds of steam, must be considered practical for a community plant which may be operated under contract by a utility. Turbine throttle conditions of 2,400 psig and 1,000°F and 1,800 psig and 950°F were selected for comparison for the fossil-fired cogeneration plants at both Geismar, Louisiana, and Orange,

Texas. The basic feedwater heating cycle included a deaerator, operating at 45 psia, and one stage of closed feedwater heating supplied with steam at 290 psia.

For comparison purposes, budgetary capital, fuel, and operating costs were estimated for the two operating pressures at each site. Similarly, the net electric power outputs were determined for each pressure to provide a basis for evaluation. The ratios of capital cost and net power output shown below represent the increase in capital cost to utilize 2,400 psig, rather than 1,800 psig, and the resulting increase in power output.

<u>Plant</u>	<u>Capital Cost Ratio</u>	<u>Net Power Ratio</u>
Orange	1.049	1.198
Geismar	1.052	1.223

These figures indicate that a 5 percent increase in capital expenditures provides a plant that produces about 20 percent more electric power.

Other analyses show that the ratio of differential heat input to differential net work is about 2,360 Btu/kWh for both plant sites. Also, the ratio of differential cost to differential net work is \$576 per kW at Orange and \$459 per kW at Geismar in 1977 dollars.

A comparison of the fixed charges and levelized operating costs for the 1,800 and 2,400 psig plants was made assuming 1985 initial operation. Both plants supply the same quantity of process steam, and recoverable heat from this steam is virtually the same. At both Orange and Geismar the total annual cost for the 2,400 psig plant is approximately 8 percent less than the cost of the 1,800 psig plant when credit is taken for the power produced. The break-even cost of purchased power is \$0.024 per kWh which is about one-third of the estimated levelized cost of power from GSU over the life of the plant.

FIGURE 4-1. RELATIONSHIP AMONG THROTTLE PRESSURE, EXHAUST PRESSURE, & kWh/1,000 LB STEAM

The above comparison clearly indicates that throttle pressure of 2,400 psig is the more economic choice when compared to 1,800 psig. To have equal annual operating costs, the capital cost of the 1,800-psig plant would have to be about 80 percent of the cost of the 2,400-psig plant. It is evident that the optimum throttle pressure lies above 1,800 psig. Because the trend in central station practice is away from the supercritical pressures aforementioned, these were ruled out in this study, and a steam pressure of 2,400 psig was selected for the fossil-fired plants at both Orange and Geismar.

4.2.2 STEAM TURBINE SELECTION

Three straight noncondensing steam turbines were selected for the Orange plant. Two turbines operate at 2,415 psia throttle pressure; one turbine exhausts at 640 psia and one exhausts at 290 psia. The third turbine operates at a throttle pressure of 290 psia and exhausts at 45 psia to provide deaerating steam. Because the flow rate to the deaerator is relatively low, it was impossible to justify turbine operation at 2,415 psia throttle pressure.

Because automatic extraction points increase turbine costs and reduce turbine efficiency, turbine selection was developed using the following rationale. For evaluation purposes, two duplicate double-automatic extraction turbines were selected for comparison with three straight noncondensing units. It was found that the extraction turbines would generate on the order of 10 percent less power than the three straight noncondensing turbines. With a fixed charge rate of 15 percent, 7,884 hours of operation per year, and a levelized power cost of \$0.0757 per kWh, the capitalized value of a power differential of 15 MW amounts to approximately \$59,700,000. This cost is nearly twice the installed cost of the two turbines, including inflation and interest during construction. It becomes evident that the most economic selection is the one that generates maximum power.

Three straight noncondensing steam turbines and one automatic extraction steam turbine operating at 2,415 psia throttle pressure were selected for the Geismar plant. Two turbines exhaust at 690 psia, one exhausts at 290 psia, and a single automatic extraction turbine supplying 370,000 lb/hr of process steam at 970 psia exhausts to the deaerator at 45 psia. An alternate arrangement was considered using three turbines with automatic extractions at 690 and 290 psia. (The latter unit would have been a prototype triple automatic noncondensing turbine.) The alternate arrangement produced on the order of 30 MW less than the turbines selected, and also resulted in being more expensive.

4.2.3 NUMBER OF FEEDWATER HEATERS

The steam used for feedwater heating generates electric power by expanding it through a turbine to heater supply pressure. The amount of electric power generated is a function of the flow and temperature of the treated condensate and makeup water, the number of stages of feedwater heating, the final feedwater temperature, and the turbine performance.

For given initial and final feedwater temperatures, the maximum work is obtained with an infinite number of stages of feedwater heating. Figure 4-2 shows this theoretical work in kWh per 1,000 pounds of condensate and makeup at 68 F for the turbine conditions listed. In practice, a deaerator operates at above atmospheric pressure and is used to reduce the dissolved oxygen contained in the feedwater to acceptable limits. Feedwater pumps take suction from the deaerator, permitting varying stages of closed feedwater heating to be employed.

In the base case, the deaerator pressure was set at 45 psia and one stage of feedwater heating employed with steam supplied at 290 psia. For comparison, an alternate was evaluated with two stages of closed feedwater heating. At the Orange plant, the second-stage heater operates at 640 psia. With two feedwater heaters, steam flow to the turbine increased 10 percent and the net electric power increased 8 percent. The second-stage heater at the Geismar plant operates at 690 psia. With two feedwater heaters the steam flow to the turbine increased 11 percent and the net power increased 9 percent.

A comparison of fixed charges and levelized operating costs for the plants with one and two stages of closed feedwater heating was made assuming the year of initial operation as 1985. The comparison showed the two stages of feedwater heating to be the most economic choice if the increase in capital cost over one stage is less than 7 percent at Orange and less than 9 percent at Geismar.

On the basis of the above criteria, a second stage of closed feedwater heating can be economically justified at both Orange and Geismar.

FIGURE 4-2. GENERATION FROM FEEDWATER HEATING SYSTEM

4.3 ORANGE SITE

4.3.1 FOSSIL FUEL PLANTS

4.3.1.1 Oil-Fired Plant (Reference Plant)

4.3.1.1.1 Steam Generators

Two 50-percent capacity, oil-fired boilers are included in this arrangement. Each boiler is rated at 1,800,000 lbs of steam per hour at 2,415 psia and 1,000 degrees FTT. This capacity permits continuous production for the projected 1985 combined demand of Firestone, Gulf Chemical, B.F. Goodrich, and DuPont. Backup steam for each plant is provided by steam-generating facilities presently contained in each plant.

Design features of the steam generators include:

- One vertical-shaft air preheater per boiler.
- One 100-percent capacity forced, and one 100-percent capacity induced, draft fan per boiler.
- Retractable soot blowers.
- Electronic combustion controls.
- Solid state automatic controls.

4.3.1.1.2 Boiler Feedwater System

The arrangement of the feedwater system is illustrated on Drawing No. 12977-EP-2E located in Appendix B. The steam cycle has been designed to provide process steam at the projected 1985 demand level of the four process plants to be served.

The basic equipment contained in this system is:

- Two deaerators, each operating at 45 psia and 248,100 lb/hr. Deaerating steam is supplied from 45 psia turbine extraction.
- Three (2 operating and 1 spare) 50-percent capacity, motor-driven, feedwater pumps arranged in parallel. Motor drivers were selected to reduce first cost.
- Two strings of two closed feedwater heaters arranged in parallel. Each of the second-stage units is rated at 161,484 lb/hr and operates on extraction steam from the 640 psia header. The

first-stage heaters are each rated at 213,605 lb/hr and operate on extraction steam from the 290 psia header. Heater drains flow to the deaerator.

4.3.1.1.3 Turbine Generators

Study is based on a total of three noncondensing steam turbines of double-shell construction with backpressure governors.

A brief description of the turbine generators follows:

- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 290 psia and 496,206 lb/hr throttle flow and 45 psia exhaust pressure. The turbine is connected to an air-cooled generator rated at 20.6 MVA, 0.9 PF, 22 kV with static excitation system.
- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,668,415 lb/hr throttle flow and 290 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated at 107.6 MVA, 0.9 PF, 22 kV with static excitation system.
- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,772,967 lb/hr throttle flow and 640 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated for 77.7 MVA, 0.9 PF, 22 kV.

4.3.1.1.4 Fuel Handling System

This system contains the equipment required to receive, store, and deliver No. 6 fuel oil to the boilers. The fuel oil was assumed to have the following composition:

	Weight %
Sulfur	2.3
Hydrogen	9.7
Carbon	85.6
Nitrogen and Oxygen	2.0
Ash	0.12
Water and sediment, Vol. %	0.74
Heating value (Btu/lb)	18,300

The fuel oil system supplies oil to the station from the railroad tank car unloading facility. Three unloading pumps, located in the fuel oil pumphouse, transport fuel oil

from tank cars to the storage tanks. Two storage tanks with a combined storage capacity of 43,500,000 gallons, store fuel oil equivalent to a 60-day burning rate.

Three 100-percent capacity pumps, one per boiler plus one common spare, are also located in the fuel oil pumphouse. These pumps transport fuel oil from the storage tanks to the boilers.

A 15-foot earth dike has been included around each tank for fire protection.

4.3.1.1.5 Ash Handling

Boilers are designed primarily for oil firing and no provisions have been included for future coal firing except that adequate headroom has been provided beneath the boiler to permit future installation of a bottom ash hopper.

For oil firing, the bottom of the boiler is sealed off with a steel plate which can be unbolted at scheduled outages for manual removal of ash accumulations. Oil soot accumulations under precipitator hoppers and other points are removed on a continuous basis through eductors and reinjected into the boiler. This system operates under positive pressure.

The arrangement is illustrated on Drawing No. 12977-EP-2D located in Appendix B.

4.3.1.1.6 Precipitators and Scrubbers

Precipitators: Two precipitators, one per boiler, are included in the cost estimate. Included in the precipitator costs are supporting structures, transformers, controls, and model study.

Precipitators were selected to comply with both state and federal regulations, which limit particulate matter emissions to 0.1 lb/10⁶ Btu heat input.

Scrubbers: Two scrubbers, one per boiler, are included in the cost estimate. Each scrubbing system consists of supporting steel; demister/absorber; limestone storage and handling equipment; limestone slurry tanks; thickener; miscellaneous pumps, tanks, piping, and duct work; controls; and a sludge handling system.

Scrubbers were selected to comply with proposed regulations which will soon require 90 percent removal of SO₂ from the flue gas. Complete duplication of all scrubber equipment was eliminated by utilizing some equipment for both scrubbers.

4.3.1.1.7 Water Treatment System

The makeup water supply passes through two clarifiers arranged in parallel, each operating at one-quarter of total plant requirements (50 percent returns are anticipated not requiring clarification). Underflow from the clarifier is pumped to a thickener.

Clarifier effluent flows by gravity to sand gravity filters. Filter backwash is recycled to the clarifier. Filter effluent is pumped through full-flow pressure carbon filters to a demineralizing system.

Dissolved solids are removed by demineralizer trains consisting of cation exchangers, vacuum degasifiers, anion exchangers, and mixed-bed exchangers. Demineralizer trains are followed by a battery of mixed-bed polishing units. Blowdown from the demineralizing system is discharged to the holding basin.

The condensate returns are put into the system ahead of the carbon filter after passing through oil removal equipment. The choice of oil removal facilities depends upon the form of oil; i.e., dissolved, suspended, or emulsified. The study design includes deep-bed precoat oil removal filters containing anthracite. The filter bed is precoated with an alum-soda ash mix and has a small continuous body feed.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2B located in Appendix B.

4.3.1.1.8 Waste Treatment System

In the October 8, 1974, Federal Register, EPA reported final effluent guidelines for the steam/electric power generating industry. The wastewater treatment described below complies with these new source performance standards.

Liquid wastes from the station include water treatment wastes (suspended solids, acid, caustic, oil), steam plant wastes (floor drainage, equipment washing wastes, boiler chemical cleaning wastes, boiler blowdown), storm drainage (yard and roof drainage), and sanitary systems.

The water treatment plant clarifier underflow is pumped to a thickener. Thickener solids are dewatered and sent to a disposal site. The overflow is recycled to the clarifier. Water from the vacuum filter is returned to the thickener.

An impervious holding or equalization basin is utilized to collect all other waste flows. These flows include floor drainage and intermittent high-flow wastes, which are high in suspended solids and dissolved metals. Equipment washing

wastes, boiler chemical cleaning wastes, and yard and roof drainage are typical examples. The basin is sized to accommodate wastes from equipment washing and boiler chemical cleaning when heavy rainfall could result in a large amount of yard drainage.

The basin effluent flows to a treatment system consisting of a settling chamber with chemical feed and neutralization to control pH within allowable limits for discharge into the river. The effluent is recirculated back to the water treatment system clarifier when total solids content and other conditions permit.

Sludge from the settling chamber is pumped to the dewatering equipment, and the oil is collected and sent to disposal. A bypass system is provided for abnormal conditions.

Sanitary wastes are treated in a package plant providing secondary biological treatment and chlorination of the treated effluent prior to discharge.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2B located in Appendix B.

4.3.1.1.9 Electrical System

The proposed oil-fired cogeneration facility generates approximately 185.3 MW (gross) of electrical power; allowing for generator losses and plant auxiliaries, the net electrical output of the plant is 155.2 MWe.

Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV or 69 kV according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1F, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of Gulf and Goodrich serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the cogeneration plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to two step-up power transformers with isolated-phase bus. One transformer, rated 90 MVA, delivers 69 kV to the plant switchyard for distribution to Goodrich, Gulf, and Firestone. The second transformer, rated 75 MVA, delivers 138 kV to the plant switchyard for distribution to DuPont.

A tap from the isolated-phase bus connects to the plant auxiliary transformer rated 40 MVA, 22 kV-4160 V and supplies all plant electrical equipment. Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 40-MVA, 22-kV - 4160-V reserve transformer. This connection assures reliability of steam production in the event of a generator or transformer failure.

Plant electrical auxiliary equipment consists of:

- 4-kV metal-clad switchgear rated 350 MVA.
- 1500-kVA load center unit substations for 480-V loads.
- 480-V motor control centers with circuit breaker combination starters.
- A wiring system composed of copper conductor, flame-retardant cable installed in a raceway system of aluminum ladder tray or rigid steel conduit.
- A lighting system utilizing fluorescent fixtures, incandescent lamps, or high bay lighting as required.
- A common grounding system throughout the plant.
- A communications/paging system.
- An emergency dc supply system derived from 125-V station batteries for small, critical loads and switchgear breaker operations.

4.3.1.1.10 Structural Criteria

Foundations: Available soil information for the proposed plant indicates that drilled caisson or pile foundations may be required for major structures and equipment. The cost estimate includes pile foundations for all plant structures, piperacks, water treatment facilities, and other small buildings. Fuel oil tanks are supported on select compacted backfill. No ringwall foundation is included.

Yardwork: The cost estimate includes clearing and grubbing the site, local excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are the costs for relocation of the existing canal, construction of two bridge structures over the canal for roadway and railroad, earth dikes for the fuel oil tanks, a waste holding basin, and various other hydraulic structures.

Buildings and Other Structures: Cost estimates of auxiliary buildings are based on a semi-outdoor design. They include two exposed boilers with enclosures over fronts and tops. Small enclosures are provided for each of the force draft fans. Common to the boilers is a 275-foot concrete stack erected on a concrete mat supported by piles. The stack is provided with steel liner, ladder, platforms, and aircraft lights.

The water treatment plant also will be outdoors, except for a single-story laboratory and control building of steel frame with insulated metal siding constructed on a concrete slab on grade. A similar building will provide office and warehouse space.

The turbine building is a steel-frame structure enclosed with uninsulated metal siding, metal roof deck with insulated built-up asphalt, and gravel roofing. It has a concrete operating floor and ground floor. Galvanized steel grating supported by steel framing is used in general for other floors, walkways, stair treads, and intermediate landings. The turbine generators are supported on concrete pedestals extending from operating floor level to below grade. The turbine building contains a control room, various switch and cable rooms, and a 50-ton capacity overhead crane to service the turbine generators.

4.3.1.2 Coal-Fired Plant

4.3.1.2.1 Steam Generators

Two 50-percent capacity, pulverized coal-fired boilers are included in this arrangement. Each boiler provides 1,800,000 pounds of steam per hour at 2,415 psia and 1,000 degrees FTT. This capacity permits continuous production for the projected 1985 combined demand of Firestone, Gulf Chemical, B.F. Goodrich, and DuPont. Backup steam is provided by the existing steam-generating facilities contained in each plant.

Design features of the steam generators include:

- One vertical-shaft air preheater per boiler.
- Two 50-percent capacity forced, and two 50-percent induced, draft fans per boiler.
- Retractable soot blowers.
- Electronic combustion controls.
- Solid state automatic burner safety controls.
- Three ball-type pulverizers with primary air fan.

4.3.1.2.2 Boiler Feedwater System

The arrangement of the feedwater system is illustrated on Drawing No. 12977-EP-2E located in Appendix B. The steam cycle was designed to provide process steam at the projected 1985 demand level of the four process plants being served.

The basic equipment contained in this system is:

- Two deaerators, each operating at 45 psia and 248,100 lb/hr. Deaerating steam is supplied from 45 psia turbine extraction.
- Three (2 operating and 1 spare) 50-percent capacity feedwater pumps, arranged in parallel. Motor drivers were selected to reduce first cost.
- Two strings of two closed feedwater heaters arranged in parallel. Each of the second-stage units is rated at 161,484 lb/hr and operates on extraction steam from the 640 psia header. The first-stage heater is rated at 213,605 lb/hr. Heater drains flow to the deaerator.

4.3.1.2.3 Turbine Generators

The study is based on a total of three noncondensing steam turbines of double-shell construction with backpressure governors.

A brief description of the turbine generators follows:

- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia 496,206 lb/hr throttle flow and 45 psia exhaust pressure. The turbine is connected to an air-cooled generator rated at 20.6 MVA, 0.9 PF, 22 kV with static excitation system.

- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,668,415 lb/hr throttle flow and 290 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated for 107.6 MVA, 0.9 PF, 22 kV with static excitation system.
- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,772,967 lb/hr throttle flow and 640 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated for 77.7 MVA, 0.9 PF, 22 kV with static excitation system.

4.3.1.2.4 Fuel Handling System

This system contains the equipment required to receive, store, and deliver coal to the boiler house silos. The characteristics of the coals considered in this study are shown in Table 4-5.

Based on the low heating value, coal consumption of the two units is estimated at 3,734 tons per day for Alabama coal and 5,671 tons per day for Wyoming coal. On a continuous basis, this amounts to 78 tons per hour per boiler for Alabama coal and 118 tons per hour per boiler for Wyoming coal. Coal will be delivered to the plant by unit train, positioned over the track hoppers, and dumped by a rotary car dumper. A general configuration of the coal handling system is shown on Drawing No. 12977-SK-1A located in Appendix B.

4.3.1.2.5 Ash Handling

There are basically two ash handling systems: one for the bottom ash and one for fly ash removal.

The bottom ash system is hydraulic, using a jet pump to convey ash to dewatering storage bins for removal by truck to an offsite disposal area. To conserve water, a closed recirculating water system containing storage and settling tanks is employed. This system permits the particles which escape from the dewatering bin to drop out of suspension and be recovered as sludge. The water is finally drained into a storage tank for reuse in filling ash hoppers and for conveying ash.

Fly ash is removed from the gas system hoppers pneumatically and conveyed to a silo where it is stored dry. When removed from the silo for final disposal, the fly ash is mixed with water and discharged to a truck for removal to an offsite disposal area.

TABLE 4-5

COAL CHARACTERISTICS

Alabama Coal (Jefferson County, Pratt Seam)

Proximate Analysis

	<u>High</u>	<u>Low</u>	<u>Mean</u>
Moisture (%)	4.0	1.0	2.1
Volatile Matter (%)	34.0	26.2	30.0
Fixed Carbon (%)	70.0	52.9	60.2
Ash (%)	17.1	3.6	9.5
Sulfur (%)	3.4	.6	1.8
Heating Value (Btu/lb)			
as Received	15,150	12,620	13,940
Ash Soft Temperature (F)	2,700	2,260	2,420
Hardgrove Grindability			
Index	85	85	

Wyoming Coal (Campbell County, Smith & Roland Seam)

Proximate Analysis

	<u>High</u>	<u>Low</u>	<u>Mean</u>
Moisture (%)	30.80	27.39	28.95
Volatile Matter (%)	33.36	28.42	31.35
Fixed Carbon (%)	37.04	31.82	33.91
Ash (%)	7.73	4.77	5.79
Sulfur (%)	0.79	0.34	0.48
Heating Value (Btu/lb)			
as Received	8,829	8,308	8,524
Ash Soft Temperature (F)	2,326	2,090	2,209
Hardgrove Grindability			
Index	60.3	46.7	52.8

Arrangement of the system is illustrated in Drawing No. 12977-EP-2C located in Appendix B.

4.3.1.2.6 Precipitators and Scrubbers

Precipitators: Two precipitators, one per boiler, are included in the cost estimate. Included in the precipitator costs are supporting structures, transformers, controls, and model study.

Precipitators were selected to comply with both state and federal regulations, which limit particulate matter emissions to 0.1 lb/10⁶ Btu heat input.

Scrubbers: Two scrubbers, one per boiler, are included in the cost estimate. Each scrubbing system consists of supporting steel; demister/absorber; limestone storage and handling equipment; limestone slurry tanks; thickener; miscellaneous pumps, tanks, piping and duct work; controls; and a sludge handling system.

Scrubbers were selected to comply with proposed regulations which will soon require 90 percent removal of SO₂ from the flue gas. Complete duplication of all scrubber equipment was eliminated by utilizing some equipment for both scrubbers.

4.3.1.2.7 Water Treatment System

The makeup water supply passes through two clarifiers arranged in parallel, each operating at one-quarter of total plant requirements (50 percent of the returns not requiring clarification are anticipated). Underflow from the clarifier is pumped to a thickener.

The clarifier effluent flows by gravity to sand gravity filters. Filter backwash is recycled to the clarifier. The filter effluent is pumped through full-flow, pressure-type carbon filters to a demineralizing system.

The dissolved solids are removed by demineralizer trains consisting of cation exchangers, vacuum degasifiers, anion exchangers, and mixed-bed exchangers. The demineralizer trains are followed by a battery of mixed-bed polishing units. Blowdown from the demineralizing system is discharged to the holding basin.

Condensate returns are put into the system ahead of the carbon filter after passing through oil removal equipment. The choice of oil removal facilities is dependent upon the form of oil; i.e., dissolved, suspended, or emulsified. The study design includes deep-bed precoat oil removal filters

containing anthracite. The filter bed is precoated with an alum-soda ash mix and has a small continuous body feed.

A fundamental flow diagram of the system is shown on Drawing No. 12977 EP-2A located in Appendix B.

4.3.1.2.8 Waste Treatment System

In the October 8, 1974, Federal Register, EPA reported final effluent guidelines for the steam/electric power generating industry. The wastewater treatment described below complies with these new source performance standards.

Liquid wastes from the station include water treatment wastes (suspended solids, acid, caustic, oil) steam plant wastes (floor drainage, equipment washing wastes, boiler chemical cleaning wastes, boiler blowdown), storm drainage (yard and roof drainage, coal pile runoff), and sanitary systems.

For coal-fired operation, the bottom ash sluicing is a closed recirculating system incorporating dewatering bins and a clarifier with makeup from the wastewater system.

The water treatment plant clarifier underflow is pumped to a thickener. Thickener solids are dewatered and sent to a disposal site. The overflow is recycled to the clarifier. Water from the vacuum filter is returned to the thickener.

An impervious holding, or equalization, basin is utilized to collect all other waste flows. These wastes include floor drainage and intermittent high-flow wastes, which are high in suspended solids and dissolved metals. Coal pile runoff, equipment washing wastes, boiler chemical cleaning wastes, and yard and roof drainage are typical examples. The basin is sized to accommodate wastes from equipment washing and boiler chemical cleaning when heavy rainfall could result in large coal pile runoff and yard drainage.

The basin effluent flows to a treatment system consisting of a settling chamber with chemical feed and neutralization to control pH within the allowable limits for discharge into the river. The effluent is used as makeup to the ash handling system, where applicable, and also may be recirculated back to the water treatment system clarifier.

Sludge from the settling chamber is pumped to the dewatering equipment, oil is collected and sent to disposal; a bypass system is provided for abnormal conditions.

Sanitary wastes are treated in a package plant providing secondary biological treatment and chlorination of the treated effluent prior to discharge.

The sulfur dioxide scrubber wastewater system is a closed system incorporating complete recirculation and requiring disposal of solids only. The three major system components are the scrubber, reaction tank, and thickener.

A limestone/water slurry passes through the scrubber where it reacts with the SO_2 laden flue gas. The reacted solution is discharged into the reaction tank where chemical reactions go to completion yielding discardable precipitates. These precipitates are settled in a thickener and removed for disposal. The clarified thickener water is returned to the scrubber along with the reusable scrubbing slurry from the reaction tank.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2A located in Appendix B.

4.3.1.2.9 Electrical System

The proposed coal-fired cogeneration facility generates approximately 185.3 MW (gross) of electrical power. Allowing generator losses and plant auxiliaries, the net electrical output of the plant is 148.6 MWe.

Existing substations located at each user's plant will be retained and modified, as necessary, to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV or 69 kV according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1D, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of Gulf and Goodrich serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the cogeneration plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to two step-up power transformers with isolated-phase bus. One transformer, rated 90 MVA, delivers 69 kV to the plant switchyard for distribution to Goodrich, Gulf, and Firestone. The second transformer, rated 75 MVA, delivers 138 kV to the plant switchyard for distribution to DuPont.

A tap from the isolated-phase bus connects to the plant auxiliary transformer rated 40 MVA, 22 kV-4160 V and supplies all plant electrical equipment.

Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 40-MVA, 22-kV - 4160-V reserve transformer. This connection will also assure reliability of steam production in the event of a generator or transformer failure.

Plant electrical auxiliary equipment consists of:

- 4-kV metal-clad switchgear rated 350 MVA.
- 1500-kVA load center unit substations for 480-V loads.
- 480-V motor control centers with circuit breaker combination starters.
- A wiring system composed of copper conductor, flame-retardant cable installed in a raceway system of aluminum ladder tray or rigid steel conduit.
- A lighting system utilizing fluorescent fixtures, incandescent lamps, or high bay lighting, as required.
- A common grounding system throughout the plant.
- A communications/paging system.
- An emergency dc supply system derived from 125-V station batteries for small critical loads and switchgear breaker operations.

4.3.1.2.10 Structural Criteria

Foundations: Available soil information for the proposed plant indicates that drilled caisson or pile foundations may be required for major structures and equipment. The cost estimate includes pile foundations for all plant structures, piperacks, water treatment facilities, and other small buildings. Fuel oil tanks are supported on select compacted backfill. No ringwall foundation is included.

Yardwork: The cost estimate includes clearing and grubbing the site, local excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are the costs for relocation of the existing canal, construction of two bridge structures over the canal for roadway and railroad, earth dikes for the fuel

oil tanks, a waste holding basin, and various other hydraulic structures.

Buildings and Other Structures: Cost estimates of auxiliary buildings are based on a semi-outdoor design. They include two exposed boilers with enclosures over fronts and tops. Small enclosures are provided for each of the force draft fans. Common to the boilers is a 275-foot concrete stack erected on a concrete mat supported by piles. The stack is provided with steel liner, ladder, platforms, and aircraft lights.

The water treatment plant also will be outdoors, except for a single-story laboratory and control building of steel frame with insulated metal siding constructed on a concrete slab on grade. A similar building will provide office and warehouse space.

The turbine building is a steel-frame structure enclosed with uninsulated metal siding, metal roof deck with insulated built-up asphalt and gravel roofing. It has a concrete operating floor and ground floor. Galvanized steel grating supported by steel framing is used in general for other floors, walkways, stair treads, and intermediate landings. The turbine generators are supported on concrete pedestals extending from operating floor level to below grade. The turbine building contains a control room, various switch and cable rooms, and a 50-ton capacity overhead crane to service the turbine generators.

4.3.2 NUCLEAR PLANTS - ADVANCED TECHNOLOGY UNDER DEVELOPMENT

4.3.2.1 Consolidated Nuclear Steam Supply System (CNSS Plant)

The CNSS is a 1200-Mwt nuclear steam supply system developed by the Babcock and Wilcox Company (B&W). B&W has prepared a conceptual design to utilize the CNSS for dual purpose steam/electric power generation.⁽¹⁹⁾ This conceptual design study, done under contract for Union Carbide (Oak Ridge National Laboratory) and the U. S. Energy Research and Development Administration, was derived from nuclear merchant ship propulsion steam systems. It is distinctly different in detail and incorporates steam generators within the reactor pressure vessel. This section reviews the highlights of the CNSS design. In addition, modifications or additions to the CNSS design which are required for this site are identified and described in sufficient detail to allow the cost estimates developed by B&W to be appropriately adjusted.

4.3.2.1.1 Nuclear Steam Supply System (NSSS)

The CNSS is a pressurized water reactor system with both the reactor core and the steam generators located inside the reactor pressure vessel. The reactor consists of 97 fuel assemblies each consisting of 208 fuel rods, 16 control rod guide tubes, and one instrumentation tube arranged in a 15 x 15 array. The fuel is uranium, enriched to about 3.43 wt. % U^{235} . The total core loading is 37 metric tons of uranium. The core is water cooled and water moderated.

The CNSS utilizes a straight-tube, tube-and-shell, once-through steam generator (OTSG) which, in the referenced study, was an integral part of the reactor pressure vessel. Primary fluid (reactor coolant) flows inside the tubes and generates steam on the shell side. At full power the CNSS produces 5,290,000 lb/hr of saturated steam at 935 psia and 536.5 F. More recent designs utilize ten modular replacement units within the reactor vessel. It is also possible to isolate these units individually.

Eight reactor coolant pumps circulate reactor coolant through the core and the once-through steam generator. The pumps are vertically mounted on penetrations in the reactor pressure vessel head.

Core reactivity is controlled by a combination of fixed burnable poison, soluble poison (boric acid) in the primary coolant and movable control rods. A chemical addition and boron recovery system is utilized to control the concentration of soluble poison in the primary coolant. Thirty-seven control rod drive mechanisms are used to position control rod assemblies within the reactor core. The control rod drive mechanisms are mounted on penetrations in the reactor pressure vessel head.

A pressurizer is utilized to control reactor coolant system pressure at about 2,250 psia. The pressurizer is a vertical cylindrical vessel connected to the reactor pressure vessel by four parallel surge lines and one spray line. Electric heating elements in the lower section of the pressurizer along with a water spray nozzle in the upper section maintain the water/steam system at a saturation pressure corresponding to the desired reactor coolant pressure.

4.3.2.1.2 Thermal Cycle

The conceptual design of the CNSS cogeneration plant was based on two major assumptions:

1. A reboiler is necessary to reduce the probability of radioactive steam being released to the industrial customers.
2. Process steam must be superheated.

A precedent for the use of a reboiler for supplying process steam using a pressured water reactor (PWR) NSSS has been set at the Midland plant.⁽²⁰⁾ This plant is a joint venture of the Consumers Power Company and Dow Chemical Company and will utilize two B&W pressured water reactors as heat sources. The reboiler will be capable of supplying 4×10^6 lb/hr of steam for Dow Chemical process use.

The use of a reboiler serves as a second barrier to the radioactive primary coolant, the first being the OTSG. Without the reboiler, relatively minor OTSG leaks would result in shutdown for repair unless there was provision for control of radioactive steam and condensate throughout the customers' plants. It is assumed that this method would not be acceptable to industrial customers nor economically justifiable.

Cogenerating without the reboiler would require either:

1. A sophisticated process radiation monitoring scheme to terminate steam to customers in the event of a tube leak in the OTSG.
2. An elaborate monitoring and control system for potentially radioactive steam/condensate throughout the customers' plants.

Alternate 1. would result in low plant reliability because relatively minor OTSG tube leaks would result in plant shutdown. Alternate 2. would be costly, require continuous maintenance, and be impractical for industrial users.

At each of the plants under consideration there is a demand for superheated steam. Much of this demand could be shifted to lower pressures by replacing mechanical driven turbines with electric motors. For the purpose of this study, however, it was assumed that all alternative plants should be designed to satisfy the existing process steam requirements. To meet these requirements an oil-fired superheater was included in the thermal cycle.

Heat balance for the CNSS cogeneration plant at the Orange, Texas, site is shown on Drawing No. 12977 EP-2G located in Appendix B. Process steam at 640 psia and 700 F is supplied directly to the turbine generator and users from the reboiler and superheater. A single automatic extraction steam turbine supplies process steam at 290 psia and deaerating steam at 45 psia. Electric generation is approximately 43 MW (gross), amounting to 4.7 percent of the heat input to the cycle. Generation could be increased to 5.5 percent through the use of a closed feedwater heater

operating at 290 psia. Economic analysis, however, indicates this method cannot be justified.

4.3.2.1.3 Plant Arrangement

The B&W study includes a plot plan and building arrangement drawings for a 400-MWe central generating plant located at a standard hypothetical site. The plot plan would have to be modified to conform to the specifics of this particular site and to reflect the plant's use for cogeneration rather than central station electric generation.

Modifications to the plant arrangement would include: elimination of the circulating water intake structure and piping; addition of oil-fired superheater with precipitator, scrubber, and stack; a fuel oil storage tank; a pumphouse; and a cooling tower. Reboilers, deaerator, and boiler feed pumps would be located in the turbine building.

The major changes from the B&W study are the addition of the following:

- No. 6 Fuel Oil-Fired Superheater Including -
 - Precipitator
 - Scrubber
 - Stack
 - Ash Handling System
 - Fuel Oil Storage Tank
 - Fuel Oil Pumps and Pumphouse
 - Reboilers
 - Deaerator
 - Boiler Feed Pumps
 - 43-MW, Noncondensing, Steam Turbine Generator
 - Cooling Towers
 - 43-MW Substation

Deletion of the following:

- 400-MW, Condensing, Steam Turbine Generator
 - Condenser
 - Circulating Water System
 - Circulating Water Intake Structure
 - 400-MW Substation

4.3.2.1.4 Reactor Containment

The CNSS reactor containment is a free-standing, bottom-supported steel vessel 45 feet in diameter and 95 feet high. The containment is further enclosed in a 4-foot thick concrete biological shield having an outside diameter of 57 feet. The containment is housed in the reactor service building.

The reactor containment in the reference design is a pressure-suppression type which utilizes a pool of water to condense steam resulting from a postulated loss of coolant accident (LOCA). The design basis LOCA for the CNSS is a double-ended rupture of one of the 3.5-inch inside diameter pressurizer surge lines. The resulting coolant loss rate is relatively slow compared to the design basis LOCA in loop-type pressurized water reactors and makes the use of pressure-suppression containment feasible. Condensing the steam from the postulated LOCA allows the containment to be relatively small while maintaining a reasonable design pressure of approximately 105 psig. More recent studies by B&W found that the LOCA can be handled with a dry containment.

The concrete biological shield provides radiation shielding and, in conjunction with the reactor service building ventilation system, an additional barrier to uncontrolled release of leakage from the containment.

4.3.2.1.5 Fuel Handling System

The fuel handling system for the CNSS is similar to that for other pressurized water reactors. Spent fuel is handled under borated water as it is transferred from the reactor pressure vessel to the spent fuel pool where it is allowed to cool for approximately one year. The spent fuel can thus be loaded, still under water, into casts for shipment to offsite storage or to a reprocessing facility.

The B&W study includes a detailed description of the various components of the fuel handling equipment and associated procedures. A critical path analysis of the refueling procedure is provided and indicates that the procedure can be completed in 392 hours (16.3 days). For the economic analysis B&W assumed a 50-day refueling outage.

Two refueling schemes were investigated by B&W; a 12-month and 15-month fuel cycle. The economic analysis presented by B&W shows a small difference in the fuel cost of the two schemes (level cost of 58.5 cents/ 10^6 Btu for the 12-month cycle and 61.2 cents/ 10^6 Btu for the 15-month cycle). While the actual cycle chosen depends on many factors, basically the 15-month cycle represents higher plant availability but results in refueling during all quarters of the year while the 12-month cycle permits refueling during a given quarter of the year, year after year. S&W based its evaluation on the 12-month cycle because we believe it would be more attractive to industrial users. The cost difference between the two refueling schemes is so small that going to a 15-month cycle would negligibly affect the results of the study.

4.3.2.1.6 Turbine Generator and Steam Cycle

Drawing No. 12977 EP-2G, located in Appendix B, illustrates the heat cycle and fundamental flow diagram for the CNSS. Basically, the steam from the CNSS is utilized as the heat source for reboilers which generate process steam to meet the projected 1985 combined demand of Firestone, Gulf Chemical, B.F. Goodrich, and Dupont. Backup steam is provided by steam-generating facilities presently contained in each plant. Steam from the reboiler is sent via an oil-fired superheater to the industrial users and expanded through a steam turbine. The exhaust from the turbine is utilized in a deaerator to preheat condensate which is either returned from the industrial users or supplied as makeup. Steam is extracted at 290 psia for industrial user consumption.

The noncondensing steam turbine with backpressure control operates with inlet steam of 640 psia and 700 degrees FTT, 1,245,872 lb/hr throttle flow and 45 psia exhaust pressure. Process steam is extracted at 290 psia at a rate of 745,000 lb/hr. The turbine is connected to a hydrogen-cooled generator rated at 47.6 MVA, 0.9 PF, 22 kV with static excitation.

A deaerator is included in the heat cycle. It operates at 45 psia and 500,872 lb/hr. Deaerating steam is supplied from the 45 psia turbine extraction.

Two (1 operating and 1 spare) 100-percent capacity, motor-driven, boiler feed pumps arranged in parallel are also included in the heat cycle.

One No. 6 fuel oil-fired superheater is included to raise the temperature of 2,695,872 lb/hr of steam from 494.9 F to 700 F to meet users' requirements.

4.3.2.1.7 Radwaste System

The CNSS radwaste system is actually composed of five separate systems:

- Reactor Coolant (RC) Waste System
- Liquid Waste System
- Waste Evaporator System
- Solid Waste Disposal System
- Gaseous Waste System

The RC waste system contains and collects liquid and gaseous waste from normal plant letdown, pressurizer relief valve discharge, leakage, and maintenance drainage. These wastes are routed to the liquid or gaseous waste systems or recycled to the primary system as appropriate.

The liquid radwaste system receives and shares liquid waste from the RC and auxiliary systems. Depending on the activity and chemical content, the wastes are routed to the waste evaporator system or the liquid waste demineralizer. Waste of low enough activity is discharged to the environment through radioactivity monitors. Gases evolved from stored liquids are routed through vent headers to the gaseous waste system.

The waste evaporator system separates liquid waste into distillate and concentrated solutions. The distillate, if pure enough, is stored for reuse or discharged. If not, it is reprocessed through the waste evaporator. The concentrate is either transferred to concentrated boric acid storage or to the solid waste disposal system depending on the results of an analysis.

The solid waste disposal system provides for packaging, storage, and offsite shipment of solid and semi-solid radioactive waste. The solid waste system is used to process low-level wastes such as contaminated rags, papers, filter cartridges, etc., and high-level wastes such as spent demineralizer resins and concentrate from the waste evaporator.

The gaseous waste systems collect waste gases from reactor plant systems in their separate vent headers: low-activity, nitrogen-rich, and hydrogen-rich. The low-activity gaseous wastes are vented through filters and the plant stack to the atmosphere. The H₂-rich gases are processed through a recombiner to reduce the quantity of H₂. The gases are then compressed and stored in decoy tanks for subsequent discharge.

The B&W report includes additional description and flow diagrams for each radioactive waste system.

4.3.2.1.8 Ultimate Heat Sink

Since this site does not have ready access to an adequate supply of river water, two 100-percent capacity (one for redundancy) cooling towers have been incorporated in B&W's design. Cooling towers will serve to remove decay heat from the reactor on shutdown.

4.3.2.1.9 Water Treatment System

Due to lack of information in the B&W report, it is not possible to elaborate on plant water treating system and equipment.

4.3.2.1.10 Electrical System

The electrical system for the CNSS is basically composed of four major parts; i.e., safety-related (Class IE), balance of plant, generation, and distribution systems.

Due to lack of information in the B&W report on safety-related systems and balance of plant systems, it is not possible to elaborate on these electrical systems and equipment. The generation equipment was described in Section 4.3.2.1.6. The following discussion is devoted to the distribution system and the apportionment of output to users.

The proposed CNSS cogeneration facility produces approximately 42 MW of electrical power. A total of 18 MWe will be used for plant auxiliaries leaving 24 MWe net output available to the users.

Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV or 69 kV according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1E, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of Gulf and Goodrich serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the cogeneration plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to two step-up power transformers with isolated-phase bus. One transformer, rated 15 MVA, delivers 69 kV to the plant switchyard for distribution to Goodrich, Gulf, and Firestone. The second transformer, rated 11 MVA, delivers 138 kV to the plant switchyard for distribution to DuPont.

A tap from the isolated-phase bus connects to the plant normal station service transformer is rated 21 MVA, 22 kV-4160 V and supplies all plant electrical equipment.

Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 21-MVA, 22-kV - 4160-V

reserve station service transformer. This connection will also assure reliability of steam production in the event of a generator or transformer failure.

4.3.2.1.11 Structural Criteria

Due to lack of information in the B&W report, it is not possible to elaborate on plant structural considerations and criteria.

4.3.2.2 High Temperature Gas-Cooled Reactor Steamer (HTGR Steamer)

The HTGR steamer is a 1200-MWt modification of the Fort St. Vrain nuclear steam supply system designed and constructed by General Atomic Company (GA).⁽²¹⁾ This section presents the highlights of the HTGR steamer design. One steamer is recommended for this site.

4.3.2.2.1 Heat Cycle Optimization

Steam Pressure Determination: Three cycles were developed, initially, by General Atomic Company to determine the optimum operating pressure. A fourth scheme was later developed to improve the heat cycle and increase power generation. Table 4-6 compares these cycles.

TABLE 4-6

COMPARISON OF FOUR CYCLES FOR HTGR STEAMER

	<u>IB</u>	<u>II</u>	<u>III</u>	<u>IV</u>
Steam Pressure, psia*	1600	2415	2968	2968
Steam Temperature, F*	940	1000	1052	1052
Process Steam, 1,000 lb/hr	2809	2800	2750.5	2195
Gross kWh/1,000 lb Process Steam	43.8	55	66	85.7**

*Leaving the superheaters of the steam generators.

**Generation based on S&W assumed efficiencies and calculations.

For a given process steam flow, Cycle II produces 25.5 percent more power than Cycle IB, and Cycle III produces 20 percent more power than Cycle II. The levelized net credit for power over the life of the plant, after taking into account the operating costs, is projected to be on the order of 80 mills/kWh. This yields a capitalized value for 1 kW of about \$3,900, (escalated capital cost plus interest during construction) assuming 7,884 hours of operation per year and a fixed charge rate of 16 percent. It is estimated that the differential capital cost per kW

between the cycles is less than this; hence, Cycle III emerges as the most economical choice. The increased power generation in Cycle IV justifies installation of the additional feedwater heating equipment.

Steam Turbine Selection: At Orange, Cycle IV is applicable without modification. Steam leaving the helium circulating turbines is supplied at 2,415 psia and 1,000 F to two straight noncondensing turbines, one exhausting at 640 psia and the other at 290 psia. Together these turbines produce about 141.6 MW. A single automatic extraction turbine would produce less power and could not be economically justified.

About 58 percent of the 640 psia steam is expanded through a third turbine to generate about 46.6 MW (gross) of electric power while providing feedwater heating steam at 381.3, 105.3, and 37.9 psia through uncontrolled extraction and an exhaust of 8.42 psia.

Number of Feedwater Heaters: The final feedwater temperature selected by the General Atomic Company is 435 F. To provide this temperature, two low-pressure heaters, a deareator operating at 100 psia, and one high-pressure heater are used. Utilizing the steam required to achieve the proposed final feedwater temperature increases the power generated by about 3 MW over the fossil-fired plant. Closed heaters operating under vacuum introduce some complications in a noncondensing cycle, but the resulting additional power makes it worth considering.

4.3.2.2.2 Nuclear Steam Supply System (NSSS)

The HTGR steamer is a high temperature gas-cooled reactor with the reactor core, steam generator, and helium circulators all located within a prestressed concrete reactor vessel (PCRV). The active core is helium cooled and contains 1,482 fuel elements in a closely packed hexagonal array, 74 control rod elements, and 37 control rod drives. Fissile U^{235} and fertile Th^{232} fuel particles contained within bonded carbonaceous rods are inserted into the hexagonal graphite moderator structures.

The HTGR has unique flexibility because it can utilize both the proliferation-proof low-enriched uranium/thorium cycle and the previously described highly enriched uranium/thorium cycle. It is important that these cycles be essentially interchangeable, so that the HTGR steamer can start with one cycle and change to another later with little operational penalty and/or modification to the reactor plant.

Two independent subsystems control core reactivity. Normal reactor control is accomplished by the 37 control rod drives

mounted in top head penetrations. Each operates a pair of control rods. An independent reserve system utilizing boronated graphite pellets is designed to scram the reactor in the event of normal control system malfunction. Pellets are dropped into the core through a guide tube to retard core activity.

Four steam turbine-driven helium circulators pump primary coolant through the core from the top of the steam generator. The circulators are mounted in penetrations on the PCRV in the plenum area under the core.

The HTGR steamer employs four steam generators to produce superheated steam used to drive the helium circulators and turbine generators. They are also mounted in penetrations on the PCRV in the plenum area under the core. Hot helium flows down over the single helically coiled steam generator bundle counter to the flow of steam and out the bottom of the shroud. Feedwater entering the steam generator flows up through parallel helical coils to the top of the bundle, through a 180 degree turnaround, and down the center to the superheater coils. At full power, with 435 F feedwater, each HTGR steamer produces 3,910,820 lb/hr of primary steam at 2,968 psia and 1,052 F. After expansion of the primary steam in the helium circulator turbines, it is available at 2,415 psia and 1,000 F for further expansion through turbine generators to provide process steam at the required pressures.

4.3.2.2.3 Plant Arrangement

The General Atomic study includes a steamer plant layout, which requires modifications to adapt it to the specific site. The reactor containment building houses the reactor, prestressed concrete reactor vessel, steam generators, helium circulators, and auxiliary systems for startup and emergency cooling.

The turbine building contains the turbine generators and other heat cycle equipment. Other buildings include facilities for helium storage, fuel storage, radioactive waste treatment, diesel generators, and plant controls.

4.3.2.2.4 Reactor Containment

The PCRV serves the dual function of containing the coolant and providing radiological shielding. This protection is provided by walls with a nominal thickness of 9 feet and heads that are nominally 15-foot thick. The PCRV, which houses the steam generators, circulators, and core, has an internal diameter of 31 feet and an internal height of 67 feet. Its exterior dimensions are 55 feet diameter and 98.8 feet high. The prestressing system employs a

combination of internal vertical tendons and 360 degree wire-wrapped circumferential tendons that are in molded channels on the outside surface of the PCRV. In the top head are penetrations and wells to house the helium purification system and neutron chamber as well as the control rod drives. Penetrations in the bottom head include those for the four steam generators and the four helium circulators.

4.3.2.2.5 Fuel Handling System

Refueling of the HTGR steamer is accomplished during shutdown and depressurized conditions while maintaining the gas-tight integrity of the prestressed concrete reactor vessel. Control rod drives are removed in an auxiliary service cask. The fuel handling equipment then removes spent fuel and installs new fuel through the control rod drive penetrations. Approximately one-quarter of the core is replaced each year. The time required for replacement of about 500 fuel elements is estimated to be 10 days.

4.3.2.2.6 Turbine Generator and Steam Cycle

Drawing No. 12977 EP-2J, located in Appendix B, illustrates the heat cycle and fundamental flow diagram for the HTGR steamer. Basically, steam generated by the HTGR is utilized to drive the four helium circulators and three steam turbine generators and provide the process steam required to meet the 1985 demand of Firestone, Gulf Chemical, B. F. Goodrich, and DuPont.

The major equipment contained in this plant consists of:

- Two noncondensing steam turbine generators rated at 3,600 rpm with backpressure governor for operation with inlet steam at 2,415 psia and 1,000 degrees FTT. One unit requires a throttle flow of 2,494,239 lb/hr exhaust to 640 psia and is connected to a hydrogen-cooled generator rated at 109.3 MVA, 0.9 PF, 13.8 kV with static excitation system. The other unit requires a throttle flow of 745,000 lb/hr, exhausts to 290 psia, and is connected to a hydrogen-cooled generator rated at 48 MVA, 0.9 PF, 13.8 kV with static excitation system.
- One noncondensing steam turbine generator rated at 3,600 rpm with backpressure governor for operation with inlet steam at 640 psia and 663.3 degrees FTT. Required throttle flow is 1,044,239 lb/hr with exhaust at 8.42 psia connected to a feedwater heater. Extractions from this turbine at 381.3, 105.3, and 37.9 psia are utilized in a deaerator, a

low-pressure heater, and a high-pressure heater for feedwater heating. The turbine is connected to a hydrogen-cooled generator rated at 51.7 MVA, 0.09 PF, 13.8 kV with static excitation.

- One feedwater heater operating at 8 psia and 266,964 lb/hr.
- One feedwater heater operating at 36 psia and 214,538 lb/hr.
- One deaerating feedwater heater operating at 100 psia and 213,152 lb/hr.
- One feedwater heater operating at 362.2 psia and 349,585 lb/hr.
- Two full-size, motor-driven feed pumps.
- One low-pressure heater drain pump.

4.3.2.2.7 Electrical System

The proposed HTGR cogeneration facility will produce approximately 188.2 MW of electrical power. A total of 19 MW will be used for plant auxiliaries leaving 169 MW net output available to the users.

The electrical system for the HTGR cogeneration facility is composed of four parts; i.e., safety-related (Class IE), balance of plant, generation, and distribution systems.

Safety-Related (Class IE) Electrical System: The Class IE electrical system provides a reliable source of electrical power for safe reactor shutdown under emergency conditions and/or during loss of offsite power. Major portions of the Class IE electrical system are:

- Standby power supply consisting of one or more diesel generators capable of supplying full power to the 4160-V safety-related buses.
- 4160-V safety-related distribution system consisting of switchgear, buswork, cable, and associated controls.
- 480-V safety-related distribution system consisting of load center substations, motor control centers, power panels, buswork cable, and associated controls.
- 120/208-V uninterruptible power supply.

- 250/125-V dc system consisting of station batteries and chargers.
- Raceway system.

Balance of Plant Electrical System: This portion of the plant electrical system is designed to supply reliable and safely controlled power to turbines, reactors, and miscellaneous plant auxiliaries during all modes of normal plant operation and shutdown conditions. Major portions of this system are:

- 4160-V normal distribution system consisting of switchgear, buswork, cable, and associated controls for nonsafety-related loads.
- 480-V normal distribution system consisting of load center substations, motor control centers, power panels, buswork, cable, and associated controls for nonsafety-related loads.
- 250/125-V dc system consisting of station batteries and chargers for supply of dc power to emergency loads of the turbine generator, feedwater, pumps, switchgear, control and instrument functions, and lighting.
- 120-V regulated instrument power system.
- Raceway system.
- Plant lighting system.
- Intraplant communications and paging system.
- Grounding system.

Generation System: Electrical power will be generated at 13.8 kV, 3 phase, 60 Hz. The 109.3-MVA, 48-MVA, and 51.7-MVA generators will each be connected to a step-up power transformer by an isolated-phase bus. The transformers, rated 53 MVA, 47 MVA, and 34 MVA, respectively, will supply 138 kV to the plant switchyard for distribution to the users. The second transformer, rated 57 MVA, will supply 138 kV to the plant switchyard for distribution to DuPont.

A tap from the isolated-phase bus will connect to the plant normal station service transformer rated 24 MVA, 13.8 kV-4160 V which supplies all of the plant auxiliary equipment.

Offsite power for plant startup and reserve will be supplied from the 138-kV switchyard through a 24-MVA reserve station service transformer. This transformer will supply the 4160-V buses during plant startup, shutdown, or emergency operation.

Distribution System: Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV. Power is transmitted from the plant via overhead lines supported on wood pole-line structures. DuPont will require new service equipment to accept 138 kV.

As shown on Drawing No. 12977-EM-1E, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of Gulf and Goodrich serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the plant generator or distribution circuit.

4.3.2.2.8 Radwaste System

The radioactive waste system of the HTGR steamer includes liquid and gas waste systems and is designed to preclude the release of activity from the plant in excess of allowable limits. Since the HTGR does not produce significant amounts of solid wastes as a result of normal operations, an elaborate handling system is not required. Solid wastes that are generated are packaged in drums and shipped offsite for disposal.

Radioactive liquids will not be produced by the HTGR steamer in substantial quantities during normal operation. However, there is a liquid waste system for handling radioactive liquids generated by infrequent evolutions such as decontamination and potential accident situations (steam generator tube failure). Low-level liquid waste is collected in a sump and pumped through a filter to a liquid waste receiver for sampling and subsequent discharge through radioactivity monitors. High-level liquid waste such as that produced during decontamination operations are prefiltered in the decontamination system before transfer to the liquid waste receivers.

Gases generated in the liquid waste receivers are vented to the gaseous waste system. Radioactive gaseous wastes from the helium purification system, fuel storage facility purge and exhaust systems, and the liquid waste receivers are collected and directed to either the low-activity inlet header or the high-activity inlet header for processing. Low-activity gases are filtered to remove particulate matter and iodine before release through the reactor plant exhaust system. High-activity gases are accumulated in storage tanks, isolated and analyzed for isotopic composition, then released at a controlled rate to the reactor plant exhaust system.

4.3.2.2.9 Water Treatment System

The nonsafety-class water treatment system consists of the equipment required for condensate demineralization, feedwater treatment, and makeup water treatment. The quality of feedwater required is similar to that for a once-through steam generating system.

The nuclear steam system does not have any planned consumption of high purity water. Bearing water drains from the main circulator service system are normally returned to the heat cycle and the quantity so drained is replenished by a makeup stream from the feedwater pump discharge. Leakage from bearing water pump shaft seals and valve stems is expected to be insignificant under normal care and maintenance. During any conditions involving combined turbine trip and loss of outside electric power, steam relief to atmosphere for limited periods would result in a demand on the storage of condensate.

The full-flow demineralizer system design is based on plant requirements. The system consists of mixed-bed demineralizers; full turbine load can be carried while one mixed-bed demineralizer is being regenerated or on standby. Post-filters are provided downstream of the demineralizers to prevent carryover of fines to the steam generators. Condensate, after passing through the gland steam condenser, flows through the mixed beds and filters and then on to the low-pressure feedwater heaters. A full-flow bypass is provided for emergency operation.

The makeup pretreatment and demineralizer system for the entire two-unit plant consists of a clarifier with sodium hypochlorite, lime, ferrous sulfate, and spare chemical feeders followed by two gravity filters and a filtered water clearwell with transfer pumps. The demineralizer section consists of two trains, each containing a carbon filter, cation, anion, and mixed-bed unit followed by a demineralized water storage tank with sufficient capacity to regenerate one complete train. Demineralized water transfer

pumps feed to the condensers for deaeration and then to the condensate storage tanks of both units.

The regeneration system consists of sulfuric acid and sodium hydroxide storage tanks, automatically controlled metering pumps, and the necessary piping, valves, and controls.

The regenerant waste disposal system accepts regeneration wastes from both the condensate polishing and makeup demineralizing systems. This system consists of a neutralizing tank, recirculation pump, mixer, and pH control for addition of acid or caustic to neutralize the regenerant wastes. The neutralized wastes are then bled at a controlled rate into the cooling tower blowdown discharge.

The pretreatment waste disposal system accepts blowdown and backwash from the clarifier, gravity filters, and carbon filters. This system consists of a compartmented sludge lagoon. The individual compartments can be successively filled and decanted with the decant water drained at a controlled rate into the cooling tower blowdown discharge.

Oily wastes from the turbine room sumps and deluge water are drained into a surge pond followed by an oil/water separator. The separated oil and sludge is transported for offsite disposal and the water is degraded in an oxidation pond before disposal at a controlled rate into the cooling tower blowdown discharge.

4.3.2.2.10 Ultimate Heat Sink

This site does not have ready access to an adequate supply of river water. Two 100-percent capacity (one for redundancy) cooling towers have been incorporated into the plant design. The cooling towers will serve to remove decay heat from the reactor on shutdown.

4.3.2.2.11 Buildings and Other Structures

This section describes the major structures of an HTGR nuclear power station. Table 4-7 lists the safety classifications of these structures. Safety classes are in conformance with present-day nuclear safety criteria.

Prestressed Concrete Reactor Vessel: The PCRV contains and shields the reactor core and the entire primary coolant system, including the steam generators and helium circulators. It functions as the primary coolant system pressure boundary. The complete PCRV is composed of: an internal steel liner acting as a sealing membrane; a thermal barrier and cooling system to limit concrete temperatures; penetrations and closures to provide access to the vessel cavities; and high-strength concrete with bonded reinforcing

steel and prestressing systems to provide strength. The entire assembly is mounted on a support structure. The liner, concrete, reinforcing steel, and prestressing systems function as a composite structural system.

Reactor Containment Building: The reactor containment building is a Safety Class 2, Seismic Category I structure which provides a leakage barrier against significant fission product release to the atmosphere following an accident. The reactor containment building allows the atmospheric density in the PCKV to be maintained as required for adequate core cooling following a design basis accident. The concrete structure also provides shielding from fission products which could be airborne within the building under accident conditions.

TABLE 4-7

SAFETY CLASSIFICATION OF STRUCTURES

<u>Structure</u>	<u>Safety*</u> <u>Class 1</u>	<u>Safety*</u> <u>Class 2</u>	<u>Safety*</u> <u>Class 3</u>	<u>No Safety**</u> <u>Class</u>
Reactor Containment Building, Penetra- tions, and Hatches		X		
Reactor Service Building		X		
Control Building		X		
Penetration Building		X		
Auxiliary Circulator Power Supply Buildings		X		
Diesel Generator Building		X		
Turbine Building				X
Helium Storage Building				X
Acid and Caustic Storage Structure				X
Raw Water Intake Building				X
Reactor Containment Building Interior Structures		X		
Substation Structures				X
Sewage Treatment Plant				X
Water Treatment Building				X
Office and Service Building				X

TABLE 4-7 (Cont)

<u>Structure</u>	<u>Safety*</u> <u>Class 1</u>	<u>Safety*</u> <u>Class 2</u>	<u>Safety*</u> <u>Class 3</u>	<u>No Safety**</u> <u>Class</u>
Auxiliary Boiler House				X
Circulating Water Pumphouse				X
Guard House				X
Warehouse				X

*Also Seismic Category I structures.

**Also nonseismic category structures.

The reactor containment building is a cylindrical, prestressed concrete structure bearing on sound soil. The foundation mat has conventional steel reinforcing. The cylindrical walls are prestressed with a post-tensioning tendon system in the vertical and horizontal directions. The dome is prestressed utilizing a three-way post-tensioning tendon system. Anchorages for the lower vertical tendon are located in a tendon gallery. Hoop tendons are anchored to three buttresses. The top vertical tendon anchorage and the dome tendon anchorage are located in the ring girder area. For easy accessibility, the PCRV tendon gallery and the reactor containment building tendon gallery have been cross-connected.

The inside surface of the reactor containment building is lined with carbon steel liner plate with stiffeners to ensure a high degree of leak-tightness for the containment. Leak chase channels are provided for the bottom liner plate and for inaccessible areas.

The polar crane with main and auxiliary hooks will be supported from the vertical building walls.

Reactor Service Building: The Safety Class 2, Seismic Category I reactor service building houses new and used fuel storage facilities and reactor auxiliary systems not located in the reactor containment building.

The primary activity in the reactor service building will be refueling. The reactor will be refueled via the reactor service building through the access door connecting the refueling floor of the reactor containment building to the

reactor service building. Both new and spent fuel are handled through this opening. Refueling equipment is normally stored in the reactor service building and will be transported into the containment through the equipment hatch, when required.

The fuel storage concrete monolith contains the spent fuel elements. This massive structure comprises the inner core of the reactor service building and is also used for storage of radioactive tools, control rods, and other equipment. The remaining portion of the reactor service building below the refueling floor houses the fuel inspection and sealing facility, equipment service facility, fuel shipping facility, shipping cask transporter parking and service area, and other auxiliary systems.

A crane mounted on the top of the reactor service building makes all lifts necessary for storing fuel in the monolith and transferring fuel to the reactor. Also, along with its auxiliary hoist, this crane performs all necessary maintenance lifts. Fuel is transferred to the reactor in a transfer cask.

The reactor service building, a multistory structure beside the reactor containment building, is structurally independent of the other buildings. The foundation is a reinforced concrete mat on sound soil.

Control Building: This is a Safety Class 2, Seismic Category I structure housing the control room, auxiliary electrical equipment, ventilation equipment, controlled access area, and the reactor plant cooling water system. The following functional areas comprise the control building:

- Control and computer rooms.
- Essential switchgear room.
- Relay and instrument room.
- Battery charging rooms.
- Ventilation equipment.
- Reactor plant cooling water system equipment.

The control building has reinforced concrete floor slabs, walls, and roof. The building is protected from possible missile damage since it contains safety-related equipment.

Interior walls are reinforced concrete including elevator and stairwell enclosures, thus meeting fire resistance criteria. Walls, floor slab, and ceiling around the control access filters and emergency charcoal filters are reinforced concrete for biological shielding.

Penetration Building: The Safety Class 2, Seismic Category I penetration building protects both safety- and nonsafety-related penetrations. The building consists of a tunnel housing electrical control and power cables and valve pits housing main steam line stop valves. It is laid out so that it completely surrounds the reactor containment building, thereby protecting the containment penetrations at different locations around the perimeter of the containment structure.

Auxiliary Circulator Power Supply Building: The Safety Class 2, Seismic Category I auxiliary circulator power supply building houses the three auxiliary circulator power supplies. The building is located on the perimeter of the electrical tunnel. Auxiliary circulator power supplies are placed 60 degrees apart within the building. Walls, roof, and mat of this structure are designed to withstand the impact of tornado-generated missiles.

Diesel Generator Building: The Safety Class 2, Seismic Category I diesel generator building houses standby power supplies, consisting of three diesel generators for each unit. All walls, interior and exterior, and the roof slab are reinforced concrete. The foundation mat is of reinforced concrete and bears on sound soil.

The diesel generator building is designed to withstand short-term tornado loading including impact of tornado-generated missiles. Openings are provided with gratings to protect against missiles.

Turbine Building: The turbine building is a nonsafety-class, nonseismic-category structure that contains the turbine generator and other equipment related to the conventional portion of the plant.

The turbine building is a multistory steel-frame structure. The roof is constructed of built-up roofing, rigid insulation, and steel deck supported by roof purlins and steel frames. The side walls are constructed of insulated metal siding. All floors are of reinforced concrete.

The turbine generator pedestal is a massive reinforced concrete structure designed to support the turbine generator with no objectionable deflections. Its natural frequency is above the dynamic vibration frequency of the turbine generator. The turbine generator pedestal is isolated from the turbine building and is supported on adequate subsoil material.

A bridge crane is provided to service the turbine building and has access to the laydown area and the railroad access bay.

Helium Storage Building: The helium storage building is a pre-engineered steel and metal-siding structure. This nonsafety-class, nonseismic-category structure houses the primary coolant helium storage bottles.

Acid and Caustic Storage Structure: This nonsafety-class, nonseismic-category structure provides storage for acid and caustic required for plant operation. This building is a lean-to of steel and metal siding.

Raw Water Intake Building: This nonsafety-class, nonseismic category structure houses equipment required for supply water from a natural source adjacent to the plant. It is a partially subgrade structure. It includes a raw water pumproom housing the raw water pumps, a fire pump pool, and a screening area housing the screening equipment.

The bottom floor slab is a reinforced concrete mat bearing on sound soil. Walls are reinforced concrete. A diesel engine, engine housing, pumps, and miscellaneous equipment are supported by a reinforced concrete floor slab.

Miscellaneous Buildings: The water treatment plant will be outdoors, except for a small laboratory and control building. Also included is a building for office and warehouse space. The buildings will be single-story, steel-framed structures with insulated metal siding built on a concrete slab on grade.

4.3.2.2.12 Other Structural Criteria

Foundations: Based on available soils information for the proposed site, it may be necessary to remove a significant amount of existing soil down to an adequate soil bearing stratum in the area of the main plant. If so, a select compacted backfill will be used to replace the removed soil. All significant structures will be supported on reinforced concrete mat foundations. Other structures and equipment will be supported on reinforced concrete spread footings or pile foundations.

Due to the groundwater level anticipated at the proposed site, extensive dewatering operations will be necessary during construction of the foundations.

Yardwork: The cost estimate includes clearing and grubbing the site, excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are the relocation of the existing canal and the construction of two bridge structures over the canal for roadway and railroad.

4.4 GEISMAR SITE

4.4.1 FOSSIL FUEL PLANTS

4.4.1.1 Oil-Fired Plant (Reference Plant)

4.4.1.1.1 Steam Generators

Two 50-percent capacity, oil-fired boilers are included in this arrangement. Each boiler is rated at 4,700,000 pounds of steam per hour at 2,415 psia and 1,000 FTT. This capacity permits continuous production for the projected 1985 combined steam demand of Monochem, Incorporated, BASF Wyandotte Chemical Company, Shell Chemical, and Vulcan Chemical. Backup steam for each plant would be provided by the steam-generating facilities presently contained in each plant.

Design features of the steam generators include:

- Two vertical-shaft air preheaters per boiler.
- Two 50-percent capacity forced, and two 50-percent capacity induced, draft fans per boiler.
- Retractable soot blowers.
- Electronic combustion controls.
- Solid state automatic burner safety controls.

4.4.1.1.2 Boiler Feedwater System

The arrangement of the feedwater system is illustrated on Drawing No. 12977-EP-2F located in Appendix B. The steam cycle was designed to provide process steam at the projected 1985 demand level of the four process plants being served.

The basic equipment contained in this system is:

- Two deaerators, each operating at 45 psia and 655,733 lb/hr. Deaerating steam is supplied from 45 psia turbine exhaust.
- Three (2 operating and 1 spare) 50-percent capacity, motor-driven feedwater pumps arranged in parallel. Motor drivers were selected to reduce first cost.

- Two strings, one for each boiler, of three closed feedwater heaters arranged in parallel. The second-stage heaters are each rated at 475,494 lb/hr and operate on extraction steam from the 690 psia header. Four quarter-size first-stage heaters, rated at 283,681 lb/hr each, operate on extraction steam from the 290 psia header. Heater drains flow to the deaerator.

4.4.1.1.3 Turbine Generators

The study is based on four noncondensing steam turbines of double shell construction with backpressure governors.

A brief description of the turbine generators follows:

- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,584,724 lb/hr throttle flow and 290 psia exhaust pressure, connected to a hydrogen-cooled generator rated at 102.2 MVA, 0.9 PF, 22 kV with static excitation system.
- One noncondensing steam turbine with backpressure governor and 970 psia extraction for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,681,466 lb/hr throttle flow and 45 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated for 147.7 MVA, 0.9 PF, 22 kV with static excitation system. Extraction flow is 370,000 lb/hr.
- Two noncondensing steam turbines with backpressure governors for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 2,985,494 lb/hr throttle flow and 690 psia exhaust pressure. Each is connected to a hydrogen-cooled generator rated for 124.3 MVA, 0.9 PF, 22 kV with static excitation system.

4.4.1.1.4 Fuel Handling System

This system contains the equipment required to receive, store, and deliver No. 6 fuel oil to the boilers. The fuel oil was assumed to have the following composition:

	Weight %
Sulfur	2.3
Hydrogen	9.7
Carbon	85.6
Nitrogen and Oxygen	2.0
Ash	0.12
Water and sediment, Vol. %	0.74
Heating value (Btu/lb)	18,300

The fuel oil system supplies oil to the station from a railroad tank car unloading facility. Three unloading pumps, located in the fuel oil pumphouse, transport fuel oil from tank cars to the storage tanks. Four storage tanks, with a combined storage capacity of 114,000,000 gallons, store fuel oil equivalent to a 60-day burning rate.

Three 100-percent capacity pumps, one per boiler plus one common spare, are also located in the fuel oil pumphouse. These pumps transport fuel oil from the storage tanks to the boilers.

A 15-foot earth dike has been included around each tank for fire protection.

4.4.1.1.5 Ash Handling

Boilers are designed primarily for oil firing and no provisions have been included for future coal firing except that adequate headroom has been provided beneath the boiler to permit future installation of a bottom ash hopper.

For oil firing, the bottom of the boiler is sealed off with a steel plate which can be unbolted at scheduled outages for manual removal of ash accumulations. Oil soot accumulations under precipitator hoppers and other points are removed on a continuous basis through eductors and reinjected into the boiler. This system operates under positive pressure.

The system is illustrated on Drawing No. 12977-EP-2D located in Appendix B.

4.4.1.1.6 Precipitators and Scrubbers

Precipitators: Two precipitators, one per boiler, are included in the cost estimate. Included in the precipitator costs are supporting structures, transformers, controls, and model study.

Precipitators were selected to comply with both state and federal regulations, which limit particulate matter emissions to 0.1 lbs/10⁶ Btu heat input.

Scrubbers: Two scrubbers, one per boiler, are included in the cost estimate. Each scrubbing system consists of supporting steel; demister/absorber; limestone storage and handling equipment; limestone slurry tanks; thickener; miscellaneous pumps, tanks, piping and duct work; controls; and a sludge handling system.

Scrubbers were selected to comply with proposed regulations, which will soon require 90 percent removal of SO₂ from the flue gas. Complete duplication of all scrubber equipment was eliminated by utilizing some equipment for both scrubbers.

4.4.1.1.7 Water Treatment System

The makeup water supply passes through two clarifiers arranged in parallel, each operating at one-quarter of total plant requirements (50-percent returns not requiring clarification are anticipated). Underflow from the clarifier is pumped to a thickener.

Clarifier effluent flows by gravity to sand gravity filters. Filter backwash is recycled to the clarifier. Filter effluent is pumped through full-flow pressure carbon filters to a demineralizing system.

Dissolved solids are removed by demineralizer trains consisting of cation exchangers, vacuum degasifiers, anion exchangers, and mixed-bed exchangers. The demineralizer trains are followed by a battery of mixed-bed polishing units. Blowdown from the demineralizing system is discharged to the holding basin.

The condensate returns are put into the system ahead of the carbon filter after passing through oil removal equipment. The choice of oil removal facilities depends upon the form of oil; i.e., dissolved, suspended, or emulsified. The study design includes deep-bed precoat oil removal filters containing anthracite. The filter bed is precoat with an alum-soda ash mix and has a small continuous body feed.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2B located in Appendix B.

4.4.1.1.8 Waste Treatment System

In the October 8, 1974, Federal Register, EPA reported final effluent guidelines for the steam electric power generating industry. The wastewater treatment described below complies with these new source performance standards.

Liquid wastes from the station include water treatment wastes (suspended solids, acid, caustic, oil), steam plant wastes (floor drainage, equipment washing wastes, boiler chemical cleaning wastes, boiler blow-down), storm drainage (yard and roof drainage), and sanitary systems.

The water treatment plant clarifier underflow is pumped to a thickener. Thickener solids are dewatered and sent to a disposal site. The overflow is recycled to the clarifier. Water from the vacuum filter is returned to the thickener.

An impervious holding or equalization basin is utilized to collect all other waste flows. These flows include floor drainage and intermittent high-flow wastes, which are high in suspended solids and dissolved metals. Equipment washing wastes, boiler chemical cleaning wastes, and yard and roof drainage are typical examples. The basin is sized to accommodate wastes from equipment washing and boiler chemical cleaning when heavy rainfall could result in a large amount of yard drainage.

The basin effluent flows to a treatment system consisting of a settling chamber with chemical feed and neutralization to control pH within the allowable limits for discharge into the river. The effluent is recirculated back to the water treatment system clarifier when the solids content and other conditions permit.

Sludge from the settling chamber is pumped to the dewatering equipment and the oil is collected and sent to disposal. A bypass system is provided for abnormal conditions.

Sanitary wastes are treated in a package plant providing secondary biological treatment and chlorination of the treated effluent prior to discharge.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2B located in Appendix B.

4.4.1.1.9 Electrical System

The proposed oil-fired cogeneration facility generates approximately 448.8 MW (gross) of electrical power. Allowing for plant generator losses and plant auxiliaries, the net electrical output is 369.7 MWe.

Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution of power among the users should be apportioned by a specific formula developed by them. Distribution voltage is 138 kV or according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1C, electrical distribution follows the piping right-of-way to each user. The switchyards of each user serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to a 395-MVA, 22-138-kV step-up power transformer through isolated-phase bus. The transformer will deliver 138 kV to the plant switchyard for distribution to the four users.

A tap from the isolated-phase bus connects to the plant auxiliary transformer rated 105 MVA, 22 kV-4160 V and supplies all plant electrical equipment.

Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 105-MVA, 22-kV - 4160-V reserve transformer. This connection also assures reliability of steam production in the event of a generator or transformer failure.

Plant electrical auxiliary equipment consists of:

- 4-kV metal-clad switchgear rated 350 MVA.
- 1500-kVA load center unit substations for 480-V loads.
- 480-V motor control centers with circuit breaker combination starters.
- A wiring system composed of copper conductor, flame-retardant cable installed in a raceway system of aluminum ladder tray or rigid steel conduit.
- A lighting system utilizing fluorescent fixtures, incandescent lamps, or high bay lighting as required.
- A common grounding system throughout the plant.
- A communications/paging system.
- An emergency dc supply system derived from 125-V station batteries for small, critical loads and switchgear breaker operations.

4.4.1.1.10 Structural Criteria

Foundations: Available soil information for the proposed plant indicates that pile foundations may be required for major structures and equipment. The cost estimate includes pile foundations for all plant structures, piperacks, water treatment facilities, and other small buildings. Fuel oil

tanks are supported on select compacted backfill. No ringwall foundation is included.

Yardwork: The cost estimate includes clearing and grubbing the site, local excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are the costs for construction of two bridge structures over the New River for roadway and railroad, earth dikes for the fuel oil tanks, a waste holding basin, and various other hydraulic structures.

Buildings and Other Structures: Cost estimates of auxiliary buildings are based on a semi-outdoor design. They include two exposed boilers with enclosures over fronts and tops. Small enclosures are provided for each of the force draft fans. Common to the boilers is a 275-foot concrete stack erected on a concrete mat supported by piles. The stack is provided with steel liner, ladder, platforms, and aircraft lights.

The water treatment plant also will be outdoors, except for a single-story laboratory and control building of steel frame with insulated metal siding constructed on a concrete slab on grade. A similar building will provide office and warehouse space.

The turbine building is a steel-frame structure enclosed with uninsulated metal siding, metal roof deck with insulated built-up asphalt, and gravel roofing. It has a concrete operating floor and ground floor. Galvanized steel grating supported by steel framing is used in general for other floors, walkways, stair treads, and intermediate landings. The turbine generators are supported on concrete pedestals extending from operating floor level to below grade. The turbine building contains a control room, various switch and cable rooms, and a 50-ton capacity overhead crane to service the turbine generators.

4.4.1.2 Coal-Fired Plant

4.4.1.2.1 Steam Generators

Two 50-percent capacity, pulverized coal-fired boilers are included in this arrangement. Each boiler is rated at 4,700,000 lb of steam per hour at 2,415 psia and 1,000 FTT. This capacity permits continuous production for the projected 1985 combined demands of Monochem Inc., BASF Wyandotte Chemical Company, Shell Chemical, and Vulcan Chemical. Backup steam is provided by the existing steam generating facilities contained in each plant.

Design features of the steam generators include:

- Two vertical shaft air preheaters per boiler.
- Two 50-percent capacity forced, and two 50-percent capacity induced, draft fans per boiler.
- Retractable soot blowers.
- Electronic combustion controls.
- Solid state automatic burner safety controls.
- Six ball-type pulverizers with primary air fans.

4.4.1.2.2 Boiler Feedwater System

The arrangement of the feedwater system is illustrated on Drawing No. 12977-EP-2F located in Appendix B. The steam cycle was designed to provide process steam at the projected early-1980 demand level of the four process plants being served.

The basic equipment contained in this system is:

- Two deaerators, each operating at 45 psia and 655,733 lb/hr. Deaerating steam is supplied from 45 psia turbine extraction.
- Three (2 operating and 1 spare) 50-percent capacity, motor-driven, feedwater pumps arranged in parallel. Motor drivers are selected to reduce first cost.
- Two strings, one for each boiler, of three closed feedwater heaters arranged in parallel. The second stage heaters are each rated at 475,494 lb/hr and operate on extraction steam from the 690 psia header. The two-stage heaters, two per boiler, are rated at 283,681 lb/hr and operate on extraction steam from the 290 psia header. Heater drains flow to the deaerator.

4.4.1.2.3 Turbine Generators

Study was made of four noncondensing steam turbines of double-shell construction with backpressure governor.

A brief description of the turbine generators follows:

- One noncondensing steam turbine with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,584,724 lb/hr throttle flow and

290 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated at 102.2 MVA, 0.9 PF, 22 kV with static excitation system.

- One noncondensing steam turbine with backpressure governor and 970 psia extraction for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 1,681,466 lb/hr throttle flow and 45 psia exhaust pressure. The turbine is connected to a hydrogen-cooled generator rated for 147.7 MVA, 0.9 PF, 22 kV with static excitation system. Extraction flow is 370,000 lb/hr.
- Two noncondensing steam turbines with backpressure governor for operation with inlet steam of 2,415 psia and 1,000 degrees FTT, 2,985,494 lb/hr throttle flow and 690 psia exhaust pressure. Each is connected to a hydrogen-cooled generator rated for 124.3 MVA, 0.9 PF, 22 kV with static excitation system.

4.4.1.2.4 Fuel Handling System

This system contains the equipment required to receive, store, and deliver coal to the boiler house silos. The characteristics of the coals considered in this study are shown in Table 4-5.

Eased on the low heating value, coal consumption for the two units is estimated at 9,928 tons per day for Alabama coal and 15,081 tons per day for Wyoming coal. On a continuous basis, this amounts to 207 tons per hour per boiler for Alabama coal and 314 tons per hour per boiler for Wyoming coal.

Coal will be received by barge, positioned by barge hauler, and unloaded by barge unloader. A general configuration of the coal handling system is shown on Drawing No. 12977-SK-1B located in Appendix B.

4.4.1.2.5 Ash Handling System

There are basically two ash handling systems: one for bottom ash and one for fly ash removal.

The bottom ash system is hydraulic, using a jet pump to convey ash to a dewatering storage bin for removal by truck to an offsite disposal area. To conserve water, a closed recirculating water system containing storage and settling tanks is employed. This system permits the particles, which escape from the dewatering bin, to drop out of suspension and be recovered as sludge. The water is finally drained to a storage tank for reuse in filling ash hoppers and for conveying ash.

Fly ash is removed from the gas system hoppers pneumatically and conveyed to a silo where it is stored dry. When removed from the silo for final disposal, the fly ash is mixed with water and discharged to a truck for removal to an offsite disposal area.

The system is illustrated on Drawing No. 12977-EP-2C located in Appendix B.

4.4.1.2.6 Precipitators and Scrubbers

Precipitators: Two precipitators, one per boiler, are included in the cost estimate. Included in the precipitator costs are supporting structures, transformers, controls, and model study.

Precipitators were selected to comply with both state and federal regulations, which limit particulate matter emissions to 0.1 lb/10⁶ Btu heat input.

Scrubbers: Two scrubbers, one per boiler, are included in the cost estimate. Each scrubbing system consists of supporting steel; demister/absorber; limestone storage and handling equipment; limestone slurry tanks; thickener; miscellaneous pumps, tanks, piping and duct work; controls; and a sludge handling system.

Scrubbers were selected to comply with proposed regulations, which will soon require 90 percent removal of SO₂ from the flue gas. Complete duplication of all scrubber equipment was eliminated by utilizing some equipment for both scrubbers.

4.4.1.2.7 Water Treatment System

The makeup water supply passes through two clarifiers arranged in parallel, each operating at one-quarter of total plant requirements (50 percent returns not requiring clarification are anticipated). Underflow from the clarifier is pumped to a thickener.

The clarifier effluent flows by gravity to sand gravity filters. Filter backwash is recycled to the clarifier. The filter effluent is pumped through full-flow pressure-type carbon filters to a demineralizing system.

The dissolved solids are removed by demineralizer trains consisting of cation exchangers, vacuum degasifiers, anion exchangers, and mixed-bed exchangers. The demineralizer trains are followed by a battery of mixed-bed polishing units. Blowdown from the demineralizing system is discharged to the holding basin.

Condensate returns are put into the system ahead of the carbon filter after passing through oil removal equipment. The choice of oil removal facilities is dependent upon the form of oil; i.e., dissolved, suspended, or emulsified. The study design includes deep-bed precoat oil removal filters containing anthracite. The filter bed is precoatd with an alum-soda ash mix and has a small continuous body feed.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2A located in Appendix B.

4.4.1.2.8 Waste Treatment System

In the October 8, 1974, Federal Register, EPA reported final effluent guidelines for the steam electric power generating industry. The wastewater treatment described below will comply with the new source performance standards.

Liquid wastes from the station include water treatment wastes (suspended solids, acid, caustic, oil), steam plant wastes (floor drainage, equipment washing wastes, boiler chemical cleaning wastes, boiler blowdown), storm drainage (yard and roof drainage, coal pile runoff), and sanitary systems.

For coal-fired operation, the bottom ash sluicing is a closed recirculating system incorporating dewatering bins and a clarifier with makeup from the wastewater system.

The water treatment plant clarifier underflow is pumped to a thickener and thickener solids are dewatered and sent to a disposal site. The overflow is recycled to the clarifier; water from the vacuum filter is returned to the thickener.

An impervious holding or equalization basin is utilized to collect all other waste flows. These flows include floor drainage and intermittent high-flow wastes, the latter of which are high in suspended solids and dissolved metals. Coal pile runoff, equipment washing wastes, boiler chemical cleaning wastes, and yard and roof drainage being typical examples. The basin is sized to accommodate wastes from equipment washing and boiler chemical cleaning when heavy rainfall could result in large coal pile runoff and yard drainage.

Basin effluent flows to a treatment system consisting of a settling chamber with chemical feed and neutralization to control pH within the allowable limits for discharge into the river. The effluent is used as makeup to the ash handling system, and also may be recirculated back to the water treatment system clarifier.

Sludge from the settling chamber is pumped to the dewatering equipment and the oil is collected and sent to disposal; a bypass system is provided for abnormal conditions.

Sanitary wastes are treated in a package plant providing secondary biological treatment and chlorination of the treated effluent prior to discharge.

The sulfur dioxide scrubber wastewater system is a closed system incorporating complete recirculation and requiring disposal of solids only. The three major system components are the scrubber, reaction tank, and thickener.

A limestone/water slurry passes through the scrubber where it reacts with the SO₂ laden flue gas. The reacted solution is discharged to the reaction tank where completed chemical reactions yield discardable precipitates. These precipitates are settled in a thickener and removed for disposal. The clarified thickener water is returned to the scrubber along with the reusable scrubbing slurry from the reaction tank.

A fundamental flow diagram of the system is shown on Drawing No. 12977-EP-2A located in Appendix B.

4.4.1.2.9 Electrical System

The proposed coal-fired cogeneration facility generates approximately 448.8 MW (gross) of electrical power. Allowing for generator losses and plant auxiliaries, the net electrical output is 352.2 MWe.

Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1A, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of each user serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to a 395-MVA, 22-138-kV step-up, power transformer through isolated-phase bus. The transformer delivers 138 kV to the plant switchyard for distribution to the four users.

A tap from the isolated-phase bus connects to the plant auxiliary transformer rated 105 MVA, 22 kV-4160 V and supplies all plant electrical equipment.

Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 105-MVA, 22-kV - 4160-V reserve transformer. This connection will also assure reliability of steam production in the event of a generator or transformer failure.

Plant electrical auxiliary equipment consists of:

- 4-kV metal-clad switchgear rated 350 MVA.
- 1500-kVA load center unit substations for 480-V loads.
- 480-V motor control centers with circuit breaker combination starters.
- Wiring system composed of copper conductor, flame-retardant cable installed in a raceway system of aluminum ladder tray or rigid steel conduit.
- A lighting system utilizing fluorescent fixtures, incandescent lamps, or high bay lighting as required.
- A common grounding system throughout the plant.
- A communications/paging system.
- An emergency dc supply system derived from 125-V station batteries for small, critical loads and switchgear breaker operations.

4.4.1.2.10 Structural Criteria

Foundations: Available soil information for the proposed plant indicates that pile foundations may be required for major structures and equipment. The cost estimate includes pile foundations for all plant structures, piperacks, water treatment facilities, and other small buildings. Fuel oil tanks are supported on select compacted backfill. No ringwall foundation is included.

Yardwork: The cost estimate includes clearing and grubbing the site, local excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are the costs for construction of two bridge structures over the New River for roadway and railroad, earth dikes for the fuel oil tanks, a waste holding basin, and various other hydraulic structures.

Buildings and Other Structures: Cost estimates of auxiliary buildings are based on a semi-outdoor design. They include two exposed boilers with enclosures over fronts and tops. Small enclosures are provided for each of the force draft fans. Common to the boilers is a 275-foot concrete stack erected on a concrete mat supported by piles. The stack is provided with steel liner, ladder, platforms, and aircraft lights.

The water treatment plant also will be outdoors, except for a single-story laboratory and control building of steel frame with insulated metal siding constructed on a concrete slab on grade. A similar building will provide office and warehouse space.

The turbine building is a steel-frame structure enclosed with uninsulated metal siding, metal roof deck with insulated built-up asphalt, and gravel roofing. It has a concrete operating floor and ground floor. Galvanized steel grating supported by steel framing is used in general for other floors, walkways, stair treads, and intermediate landings. The turbine generators are supported on concrete pedestals extending from operating floor level to below grade. The turbine building contains a control room, various switch and cable rooms, and a 50-ton capacity overhead crane to service the turbine generators.

Coal Barge Unloading Dock: A coal barge unloading dock and associated access structures are included in the cost estimate. It is based on using coffer dam cells filled with granular material. Not included in the estimate are dredging and modifications to existing revetment systems for bank erosion control.

4.4.2 NUCLEAR PLANTS - ADVANCED TECHNOLOGY UNDER DEVELOPMENT

4.4.2.1 Consolidated Nuclear Steam Supply System (CNSS Plant)

The CNSS is a 1200-Mwt nuclear steam supply system developed by the Babcock and Wilcox Company (B&W). B&W has prepared a conceptual design to utilize the CNSS for dual purpose steam/electric power generation.⁽¹⁹⁾ This conceptual design study, done under contract for Union Carbide (Oak Ridge

National Laboratory) and the U.S. Energy Research and Development Administration, was derived from nuclear merchant ship propulsion steam systems. It is distinctly different in detail and incorporates steam generators within the reactor pressure vessel. This section reviews the highlights of the CNSS design. In addition, modifications or additions to the CNSS design which are required for this site are identified and described in sufficient detail to allow the cost estimates developed by B&W to be appropriately adjusted.

4.4.2.1.1 Nuclear Steam Supply System (NSSS)

The CNSS is a pressurized water reactor system with both the reactor core and the steam generators located inside the reactor pressure vessel. The reactor consists of 97 fuel assemblies each consisting of 208 fuel rods, 16 control rod guide tubes, and one instrumentation tube arranged in a 15 x 15 array. The fuel is uranium, enriched to about 3.43 wt. % U^{235} . The total core loading is 37 metric tons of uranium. The core is water cooled and water moderated.

The CNSS utilizes a straight-tube, tube-and-shell, once-through steam generator (OTSG) which, in the referenced study, was an integral part of the reactor pressure vessel. Primary fluid (reactor coolant) flows inside the tubes and generates steam on the shell side. At full power the CNSS produces 5,290,000 lb/hr of saturated steam at 935 psia and 536.5 F. More recent designs incorporate ten modular replacement units within the reactor vessel. It is also possible to isolate each unit individually.

Eight reactor coolant pumps circulate reactor coolant through the core and the once-through steam generator. The pumps are vertically mounted on penetrations in the reactor pressure vessel head.

Core reactivity is controlled by a combination of fixed burnable poison, soluble poison (boric acid) in the primary coolant, and movable control rods. A chemical addition and boron recovery system is utilized to control the concentration of soluble poison in the primary coolant. Thirty-seven control rod drive mechanisms are used to position control rod assemblies within the reactor core. The control rod drive mechanisms are mounted on penetrations in the reactor pressure vessel head.

A pressurizer is utilized to control reactor coolant system pressure at about 2,250 psia. The pressurizer is a vertical cylindrical vessel connected to the reactor pressure vessel by four parallel surge lines and one spray line. Electric heater elements in the lower section of the pressurizer along with a water spray nozzle in the upper section

maintain the water/steam system at a saturation pressure corresponding to the desired reactor coolant pressure.

4.4.2.1.2 Thermal Cycle

The conceptual design of the CNSS cogeneration plant was based on two major assumptions:

1. A reboiler is necessary to reduce the probability of radioactive steam being released to the industrial customers.
2. Process steam must be superheated.

A precedent for using a reboiler to supply process steam using a pressured water reactor (PWR) NSSS has been set at the Midland plant.⁽²⁰⁾ This plant is a joint venture of the Consumers Power Company and Dow Chemical Company and will utilize two B&W pressured water reactors as heat sources. The reboiler is capable of supplying 4×10^6 lb/hr of steam for Dow Chemical process use. A reboiler is necessary for the cogeneration application to minimize the radioactivity steam release to the industrial users. The reboiler serves as a second barrier to the radioactive primary coolant. The once-through steam generator is the first barrier. Cogenerating without the reboiler would require either:

1. A sophisticated process radiation monitoring scheme to terminate steam to customers in the event of a tube leak in the once-through steam generator.
2. An elaborate monitoring and control system for potentially radioactive steam/condensate throughout the customer's plants.

Alternate 1. would result in low plant reliability because relatively minor once-through steam generator tube leaks would result in plant shutdown. Alternate 2. would be costly, require continuous maintenance, and be impractical for industrial users.

The conceptual design for the CNSS cogeneration plant for the Geismar region includes two 1200-MWt reactors. These reactors will operate at about 60-percent capacity for the design process steam requirements. Either reactor alone can provide approximately 80 percent of the steam requirements, reducing the need for backup heat sources. There is also ample margin for expansion.

A reboiler and No. 6 fuel oil-fired superheater provide steam at 690 psia and 750 F. About 74 percent of this is process steam. The remainder is expanded through a single

automatic extraction noncondensing turbine supplying process steam at 290 psia and deaerating steam at 45 psia.

At the Geismar site there is a Monochem requirement of 370,000 lb/hr of steam at 970 psia and 850 F. The design includes a No. 6 fuel oil-fired steam generator to provide this requirement. The steam generator is supplied with feedwater from the main feedwater pumps through booster pumps. Feedwater heating is obtained from the deaerator which receives its heat from the turbine exhaust.

About 80 percent of the total heat input to the cycle is provided by the nuclear reactors. Gross electric generation is 3.8 percent of the total heat input. These numbers reflect the basic limitations of a PWR system for cogeneration.

4.4.2.1.3 Plant Arrangement

The B&W study includes a plot plan and building arrangement drawings for a 400-MWe central generating plant located at a standard hypothetical site. The plot plan would have to be modified to conform to the specifics of this particular site and to reflect the plant's use for cogeneration rather than central station electric generation.

Modifications to the plant arrangement would include elimination of the circulating water intake structure and piping and addition of oil-fired superheater and boiler, each with a precipitator and common scrubber and stack, fuel oil storage tank, and pumphouse. Reboilers, deaerator, and boiler feed pumps would be located in the turbine building.

The major changes from the B&W study are addition of the following:

- No. 6 Fuel Oil-Fired Superheater Including -
 - Precipitator
 - Ash Handling System
- No. 6 Fuel Oil-Fired Boiler Including -
 - Precipitator
 - Ash Handling System
- Stack - Common to Superheater and Boiler
- Scrubber - Common to Superheater and Boiler
- Reboilers
- 91-MW, Noncondensing, Steam Turbine Generator
- Deaerator
- Boiler Feed Pumps
- 91-MW Substation
- Fuel Oil Storage Tank
- Fuel Oil Pumps and Pumphouse

Deletion of the following:

- Two 400-MW, Condensing Turbine Generators
- Two Condensers
- Two Circulating Water Systems
- Two Circulating Water Intake Structures
- Two 400-MW Substations

4.4.2.1.4 Reactor Containment

The CNSS reactor containment, as described in the referenced study, is a free-standing, bottom-supported steel vessel 45 feet in diameter and 95 feet high. The containment is further enclosed in a 4-foot thick concrete biological shield with a 57-foot outside diameter. The containment is housed in the reactor service building.

The reactor containment in the referenced study is a pressure-suppression type which utilizes a pool of water to condense steam resulting from a postulated loss of coolant accident (LOCA). The design basis LOCA for the CNSS is a double-ended rupture of one of the 3.5-inch inside diameter pressurizer surge lines. The resulting coolant loss rate is relatively slow compared to the design basis LOCA in loop-type pressurized water reactors and makes the use of pressure-suppression containment feasible. Condensing the steam from the postulated LOCA allows the containment to be relatively small while maintaining a reasonable design pressure of approximately 105 psig. More recent studies by B&W have found that the LOCA can be handled with a dry containment.

The concrete biological shield provides radiation shielding and, in conjunction with the reactor service building ventilation system, an additional barrier to uncontrolled release of leakage from the containment.

4.4.2.1.5 Fuel Handling System

The fuel handling system for the CNSS is similar to that for other pressurized water reactors. Spent fuel is handled under borated water as it is transferred from the reactor pressure vessel to the spent fuel pool where it is allowed to cool for approximately 1 year. The spent fuel can thus be loaded, still underwater, into casks for shipment to offsite storage or to a reprocessing facility.

The B&W study includes a detailed description of the various components of the fuel handling equipment and the associated procedures. A critical path analysis of the refueling procedure is provided which indicates that the procedure can be completed in 392 hours (16.3 days). For the economic analysis B&W assumed a 50-day refueling outage.

Two refueling schemes were investigated by B&W; a 12-month and 15-month fuel cycle. The economic analysis presented by B&W shows a small difference in the fuel cost for the two schemes (levelized cost of 58.5 cents/10⁶ Btu for the 12-month cycle and 61.2 cents/10⁶ Btu for the 15-month cycle). While the actual cycle chosen depends on many factors, basically the 15-month cycle represents higher plant availability but results in refueling during all quarters of the year, while the 12-month cycle permits refueling during a given quarter of the year, year after year. We have based our evaluation on the 12-month cycle because we believe it would be more attractive to industrial users. The cost difference between the two refueling schemes is so small that going to the 15-month cycle would have negligible affect on the results of the study.

4.4.2.1.6 Turbine Generator and Steam Cycle

Drawing No. 12977 LP-2H, located in Appendix B, illustrates the heat cycle and fundamental flow diagram for the CNSS. Basically, the steam from the CNSS is utilized as the heat source for reboilers which generate steam to meet the projected 1985 combined demands of Monochem Inc., BASF Wyandotte Chemical Company, Shell Chemical, and Vulcan Chemical. If required, backup steam is provided by existing steam generating facilities. Steam from the reboiler is sent via an oil-fired superheater to the industrial users and expanded through a steam turbine. The exhaust of the turbine is utilized in a deaerator to preheat condensate which is either returned from the industrial users or supplied as makeup. Steam is extracted at 290 psia for industrial user consumption. Included in this arrangement is a No. 6 fuel oil-fired boiler rated at 370,000 lb/hr of steam at 970 psia and 850 F. Major boiler accessories include feedwater pumps, precipitator, scrubber, and a common stack for boiler and superheater.

The noncondensing steam turbine with backpressure control operates with inlet steam of 690 psia and 750 degrees FTT, 1,764,539 lb/hr throttle flow and 45 psia exhaust pressure. Process steam is extracted at 290 psia at a rate of 450,000 lb/hr. The turbine is connected to a hydrogen-cooled generator rated at 100 MVA 0.9 PF, 22 kV with static excitation system.

A deaerator is included in the heat cycle. It operates at 45 psia and 1,314,539 lb/hr. Deaerating steam is supplied from the 45 psia turbine extraction.

Three 50-percent capacity, motor-driven boiler feed pumps arranged in parallel are also included in the heat cycle.

One No. 6 fuel oil-fired superheater is included to raise the temperature of 6,784,539 lb/hr of steam from 503.1 F to 750 F to meet users' requirements.

4.4.2.1.7 Radwaste System

The CNSS radwaste system is actually composed of five separate systems:

- Reactor Coolant (RC) Waste System
- Liquid Waste System
- Waste Evaporator System
- Solid Waste Disposal System
- Gaseous Waste System

The RC waste system contains and collects liquid and gaseous waste from normal plant letdown, pressurizer relief valve discharge, leakage, and maintenance drainage. These wastes are routed to the liquid or gaseous waste systems or recycled to the primary system as appropriate.

The liquid radwaste system receives and shares liquid waste from the RC and auxiliary systems. Depending on the activity and chemical content, the wastes are routed to the waste evaporator system or the liquid waste demineralizer. Waste of low enough activity is discharged to the environment through radioactivity monitors. Gases evolved from stored liquids are routed through vent headers to the gaseous waste system.

The waste evaporator system separates liquid into distillate and concentrated solutions. The distillate, if pure enough, is stored for reuse or discharged. If not, it is reprocessed through the waste evaporator. The concentrate is either transferred to concentrated boric acid storage or to the solid waste disposal system depending on analysis results.

The solid waste disposal system provides for packaging, storage, and offsite shipment of solid and semi-solid radioactive wastes. The solid waste system is used to process low-level wastes such as contaminated rags, papers, filter cartridges, etc., and high-level wastes such as spent demineralizer resins and concentrate from the waste evaporator.

The gaseous waste systems collect waste gases from reactor plant systems in their separate vent headers: low activity, nitrogen-rich, and hydrogen-rich. The low-activity gaseous wastes are vented through filters and the plant stack to the atmosphere. The H₂-rich gases are processed through a recombiner to reduce the quantity of H₂. The gases are then

compressed and stored in decay tank for subsequent discharge.

The B&W report includes additional descriptions and flow diagrams for each radioactive waste system.

4.4.2.1.8 Ultimate Heat Sink

Since this site has ready access to Mississippi River water, B&W design was found adequate for decay heat removal and no changes to the system were necessary.

4.4.2.1.9 Water Treatment System

Due to lack of information in the B&W report, it is not possible to elaborate on the plant water treating system and equipment.

4.4.2.1.10 Electrical System

The electrical system for the CNSS is basically composed of four major parts; i.e., safety-related (Class IE), balance of plant, generation, and distribution systems.

Due to lack of information in the B&W report on safety-related and balance of plant systems, it is not possible to elaborate on these plant electrical systems and equipment.

The generation equipment is described in Section 4.4.2.1.6. The following discussion is devoted to the distribution system and the apportionment of output to users.

The proposed CNSS cogeneration facility produces approximately 89 MW of electrical power. A total of 50 MWe will be used for plant auxiliaries leaving 39 MWe net output available to the users.

Existing substations located at each user's plant are being retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements to any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV or according to present user service. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM-1B, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of each user serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the cogeneration plant generator or distribution circuit.

Power is generated at 22 kV, 3 phase, 60 Hz and connected to a 41-MVA, 22-138-kV step-up power transformer through isolated-phase bus. The transformer delivers 138 kV to the plant switchyard for distribution to the four users.

A tap from the isolated-phase bus connects to the plant normal station service transformer rated 58 MVA, 22 kV-4160 V and supplies all plant electrical equipment.

Power for startup of the plant and reserve supply for auxiliaries is provided by means of a 138-kV tie from GSU to the plant switchyard and then to a 58-MVA, 22-kV - 4160-V reserve station service transformer. This connection also assures reliability of steam production in the event of a generator or transformer failure.

4.4.2.1.11 Structural Criteria

Due to lack of information in the B&W report, it is not possible to elaborate on plant structural considerations and criteria.

4.4.2.2 High Temperature Gas-Cooled Reactor Steamer (HTGR Steamer)

The HTGR steamer is a 1200-MWt modification of the Fort St. Vrain nuclear steam supply system which was designed and constructed by General Atomic Company.⁽²¹⁾ This section presents the highlights of the HTGR steamer design. Three steamers are recommended for this site.

4.4.2.2.1 Heat Cycle Optimization

Steam Pressure Determination: The cycles developed by the General Atomic Company for the HTGR steamer at Orange were also applicable to the cogeneration plant at Geismar. As determined in Section 4.3.2.2.1, Cycle IV was selected because of the increased power generation resulting from the higher throttle pressure and higher feedwater temperature. The following table compares the various cycles.

TABLE 4-8

COMPARISON OF FOUR CYCLES FOR HTGR STEAMER

	<u>IB</u>	<u>II</u>	<u>III</u>	<u>IV</u>
Steam Pressure, psia*	1600	2415	2968	2968
Steam Temperature, A*	940	1000	1052	1052
Process Steam, 1000 lb/hr	2809	2800	2750.5	2195
Gross kWh/1000 lb Process Steam	43.8	55	66	85.7**

*Leaving the superheaters of the steam generators.

**Generation based on S&W assumed efficiencies and calculations.

For a given process steam flow, Cycle II produces 25.5 percent more power than Cycle IB, and Cycle III produces 20 percent more power than Cycle II. The levelized net credit for power over the life of the plant, after taking into account the operating costs, is projected to be on the order of 80 mills/kWh. This yields a capitalized value for 1 kW of about \$3,900, (escalated capital costs plus interest during construction) assuming 7,884 hours of operation per year and a fixed charge rate of 16 percent. It is estimated that the differential capital cost per kW between the cycles is less than this; hence, Cycle III emerges as the most economical choice.

Steam Turbine Selection: Cycle IV was adapted to the process steam requirements at Geismar by adding an extraction at 970 psia and increasing the 640 psia to 690 psia. The three reactors required to meet the projected 1985 steam demand will initially operate at about 74-percent capacity. The 690 psia steam which constitutes 86 percent of the process requirements will be provided by two straight noncondensing turbines each rated at 94.1 MW. The 970 psia steam is provided by a single automatic extraction turbine which exhausts at 290 psia. Separate turbines were considered for these two pressures but were found to be marginal. The feedwater heating steam is provided by a triple uncontrolled extraction turbine which exhausts at 8.42 psia. A throttle pressure of 2,415 psia was used for this unit for a slightly better efficiency and corresponding increase in electric output.

Number of Feedwater Heaters: The final feedwater temperature selected by the General Atomic Company is 435 F. To provide this temperature, a high-pressure deaerator (100 psia) is utilized in conjunction with two low-pressure heaters operating at 8 psia and 36 psia and a high-pressure heater operating at 362.2 psia. This arrangement generates about 8 MW more than the fossil-fired arrangement. Closed

heaters operating under vacuum introduce some complications in a noncondensing cycle, but the additional power produced makes it attractive.

4.4.2.2.2 Nuclear Steam Supply System (NSSS)

The HTGR steamer is a high temperature gas-cooled reactor with the reactor core, steam generator, and helium circulators all located within a prestressed concrete reactor vessel (PCRVR). The active core is helium-cooled and contains 1,482 fuel elements in a closely packed hexagonal array, 74 control rod elements, and 37 control rod drives. Fissile U^{235} and fertile Th^{232} fuel particles contained within bonded carbonaceous rods are inserted into the hexagonal graphite moderator structures.

The HTGR has unique flexibility because it can utilize both the proliferation-proof low-enriched uranium/thorium cycle and the previously described highly enriched uranium/thorium cycle. It is important that these cycles be essentially interchangeable, so that the HTGR steamer can start with one cycle and change to another later with little operational penalty and/or modification to the reactor plant.

Two independent subsystems control core reactivity. Normal reactor control is accomplished by 37 control rod drives mounted in top head penetrations. Each operates a pair of control rods. An independent reserve system utilizing boronated graphite pellets is designed to scram the reactor in the event of normal control system malfunction. Pellets are dropped into the core through a guide tube to retard core activity.

Four steam turbine driven helium circulators pump primary coolant through the core from the top of the steam generator. The circulators are mounted in penetrations on the PCRVR in the plenum area under the core.

The HTGR steamer employs four steam generators to produce superheated steam used to drive the helium circulators and turbine generators. They are also mounted in penetrations on the PCRVR in the plenum area under the core. Hot helium flows down over the single helically coiled steam generator bundle counter to the flow of steam and out the bottom of the shroud. Feedwater entering the steam generator flows up through parallel helical coils to the top of the bundle, through a 180°F turnaround, and down the center to the superheater coils. At full power, with 435°F feedwater, each HTGR steamer produces 3,910,820 lb/hr of primary steam at 2,968 psia and 1,052°F. After expansion of the primary steam in the circulator turbines, it is available at 2,415 psia and 1,000°F for process use.

4.4.2.2.3 Plant Arrangement

The General Atomic study includes a steamer plant layout which requires modifications to adapt it to the specific site. The reactor containment building houses the reactor, prestressed concrete reactor vessel, steam generators, helium circulators, and auxiliary systems for startup and emergency cooling.

The turbine building contains the turbine generators and other heat cycle equipment. Other buildings include facilities for helium storage, fuel storage, radioactive waste treatment, diesel generators, and plant controls.

4.4.2.2.4 Reactor Containment

The PCRV serves the dual function of containing the coolant and providing radiological shielding. This protection is provided by walls with a nominal thickness of 9 feet and heads that are nominally 15 feet thick. The PCRV, which houses the steam generators, circulators, and the core, has an internal diameter of 31 feet and an internal height of 67 feet. Its exterior dimensions are 55 feet diameter and 98.8 feet high. The prestressing system employs a combination of internal vertical tendons and 360° wire-wrapped circumferential tendons that are in molded channels on the outside surface of the PCRV. In the top head are penetrations and wells to house the helium purification system and neutron chamber as well as the control rod drives. Penetrations in the bottom head include those for the four steam generators and the four helium circulators.

4.4.2.2.5 Fuel Handling System

Refueling of the HTGR steamer is accomplished during shutdown and depressurized conditions while maintaining the gas-tight integrity of the prestressed concrete reactor vessel. Control rod drives are removed in an auxiliary service cask. The fuel handling equipment then removes spent fuel and installs new fuel through the control rod drive penetrations. Approximately one-quarter of the core is replaced each year. The time required for replacement of about 500 fuel elements is estimated to be 10 days.

4.4.2.2.6 Turbine Generator and Steam Cycle

Drawing No. 12977 EP-2J, located in Appendix B, illustrates the heat cycle and fundamental flow diagram for the HTGR steamer. Basically, steam generated by the three HTGR's is utilized to drive the helium circulators and the four steam turbine generators and to provide the process steam required to meet the 1985 steam demand of Monochem Inc., BASF

Wyandotte Chemical Company, Shell Chemical, and Vulcan Chemical.

The major equipment contained in this plant consists of:

- Four noncondensing steam turbine generators rated at 3,600 rpm with backpressure governor for operation with inlet steam at 2,415 psia and 1,000 FTT.

Two units each require a throttle flow of 2,510,000 lb/hr exhaust to 690 psia and are connected to hydrogen-cooled generators rated at 104.5 MVA, 0.9 PF, 13.8 kV with static excitation.

One unit requires a throttle flow of 820,000 lb/hr, exhausts to 290 psia and is connected to an air-cooled generator rated at 40 MVA, 0.9 PF, 13.8 kV with static excitation system. Extraction from this turbine provides 370,000 lb/hr of 970 psia process steam.

One unit requires a throttle flow of 2,793,414 lb/hr, exhausts to a feedwater heater at 8.42 psia, and is connected to a hydrogen-cooled generator rated at 265 MVA, 0.9 PF, 22 kV with static excitation. Extractions from this turbine at 3,813 psia and 936,648 lb/hr, 105.3 psia and 570,114 lb/hr, and 37.9 psia, and 573,544 lb/hr are utilized for feedwater heating in two shell-and-tube heaters and a dearating.

- One deaerating feedwater heater operating at 100 psia and 570,114 lb/hr.
- Four one-third capacity motor-driven feed pumps.
- One low-pressure heater drains pump.
- One shell-and-tube low-pressure heater operating at 8 psia and a steam flow of 713,108 lb/hr.
- One shell-and-tube low pressure heater operating at 36 psia and 573,544 lb/hr.
- One shell-and-tube high-pressure heater operating at 362.2 psia and 936,648 lb/hr.

4.4.2.2.7 Electrical System

The proposed HTGR cogeneration facility will produce approximately 462.1 MW of electrical power. A total of

72 MW will be used for plant auxiliaries leaving 391 MW net output available to the users.

The electrical system for the HTGR cogeneration facility is composed of four parts; i.e., safety-related (Class IE), balance of plant generation, and distribution systems.

Safety- Related (Class IE) Electrical System: The Class IE electrical system provides a reliable source of electrical power for safe reactor shutdown under emergency conditions and/or during loss of offsite power. Major portions of the Class IE electrical system are:

- Standby power supply consisting of one or more diesel generators capable of supplying full power to the 4160-V safety-related buses.
- 4160-V safety-related distribution system consisting of switchgear, buswork, cable, and associated controls.
- 480-V safety-related distribution system consisting of load center substations, motor control centers, power panels, buswork cable, and associated controls.
- 120/208-V uninterruptible power supply.
- 250/125-V dc system consisting of station batteries and chargers.
- Raceway system.

Balance of Plant Electrical System: This portion of the plant electrical system is designed to supply reliable and safely controlled power to turbines, reactors, and miscellaneous plant auxiliaries during all modes of normal plant operation and shutdown conditions. Major portions of this system are:

- 4160-V normal distribution system consisting of switchgear, buswork, cable, and associated controls for nonsafety-related loads.
- 480-V normal distribution system consisting of load center substations, motor control centers, power panels, buswork, cable, and associated controls for nonsafety-related loads.
- 250/125-V dc system consisting of station batteries and chargers for supply of dc power to emergency loads of the turbine generator, feedwater, pumps,

switchgear, control and instrument functions, and lighting.

- 120-V regulated instrument power system.
- Raceway system.
- Plant lighting system.
- Intraplant communications and paging system.
- Grounding system.

Generation System: Power will be generated by means of four generators rated 104.5, 104.5, 40, and 265 MVA as described earlier. Each generator will be connected to a step-up power transformer by means of isolated-phase bus. The four step-up power transformers will be rated 76, 76, 39, and 233 MVA, respectively.

Auxiliary power for the plant will be provided by three 27-MVA, normal station service transformers connected to three of the four generators through a tap in the isolated-phase bus.

Offsite power for plant startup and reserve will be supplied from the 138-kV switchyard through three 27-MVA reserve station service transformers. These transformers will supply the 4160-V buses for each of the three units during startup, shutdown, or emergency operation.

Distribution System: Existing substations located at each user's plant will be retained and modified as necessary to allow integration of the cogenerated electrical power with the present supply from GSU. The distribution system between the cogeneration plant and the users is capable of delivering 100 percent of the electrical requirements of any user. The distribution of power among the users should be apportioned by a specific formula developed by them.

Distribution voltage is 138 kV. Power is transmitted from the plant via overhead lines supported on wood pole-line structures.

As shown on Drawing No. 12977-EM1B, located in Appendix B, electrical distribution follows the piping right-of-way to each user. The switchyards of each user also serve as tie points for the distribution circuit.

Reliability is achieved by maintaining power availability from GSU in the event of a failure of the plant generator or distribution circuit.

4.4.2.2.8 Radwaste System

The radioactive waste system of the HTGR steamer includes liquid and gas waste systems and is designed to preclude the release of activity from the plant in excess of allowable limits. Since the HTGR does not produce significant amounts of solid wastes as a result of normal operations, an elaborate handling system is not required. Solid wastes that are generated are packaged in drums and shipped offsite for disposal.

Radioactive liquids will not be produced by the HTGR steamer in substantial quantities during normal operation. However, there is a liquid waste system for handling radioactive liquids generated by infrequent evolutions such as decontamination, and potential accident situations (steam generator tube failure). Low-level liquid waste is collected in a sump and pumped through a filter to a liquid waste receiver for sampling and subsequent discharge through radioactivity monitors. High-level liquid waste such as that produced during decontamination operations are prefiltered in the decontamination system before transfer to the liquid waste receivers.

Gases generated in the liquid waste receivers are vented to the gaseous waste system. Radioactive gaseous wastes from the helium purification system, fuel storage facility purge and exhaust systems, and the liquid waste receivers are collected and directed to either the low-activity inlet header or the high-activity inlet header for processing. Low-activity gases are filtered to remove particulate matter and iodine before release through the reactor plant exhaust system. High-activity gases are accumulated in storage tanks, isolated, and analyzed for isotopic composition and then released at a controlled rate to the reactor plant exhaust system.

4.4.2.2.9 Water Treatment System

The nonsafety-class water treatment system consists of the equipment required for condensate demineralization, feedwater treatment, and makeup water treatment. The quality of feedwater required is similar to that for a once-through steam generating system.

The nuclear steam system does not have any planned consumption of high purity water. Bearing water drains from the main circulator service system are normally returned to the heat cycle and the quantity so drained is replenished by a makeup stream from the feedwater pump discharge. Leakage from bearing water pump shaft seals and valve stems is expected to be insignificant under normal care and maintenance. During any conditions involving combined

turbine trip and loss of outside electric power, steam relief to atmosphere for limited periods would result in a demand on the storage of condensate.

The full-flow demineralizer system design is based on plant requirements. The system consists of mixed-bed demineralizers; full turbine load can be carried while one mixed-bed demineralizer is being regenerated or on standby. Post-filters are provided downstream of the demineralizers to prevent carryover of fines to the steam generators. Condensate, after passing through the gland steam condenser, flows through the mixed beds and filters and then on to the low-pressure feedwater heaters. A full-flow bypass is provided for emergency operation.

The makeup pretreatment and demineralizer system for the entire two-unit plant consists of a clarifier with sodium hypochlorite, lime, ferrous sulfate, and spare chemical feeders followed by two gravity filters and a filtered water clearwell with transfer pumps. The demineralizer section consists of two trains, each containing a carbon filter, cation, anion, and mixed-bed unit followed by a demineralized water storage tank with sufficient capacity to regenerate one complete train. Demineralized water transfer pumps feed to the condensers for deaeration and then to the condensate storage tanks of both units.

The regeneration system consists of sulfuric acid and sodium hydroxide storage tanks, automatically controlled metering pumps, and the necessary piping, valves, and controls.

The regenerant waste disposal system accepts regeneration wastes from both the condensate polishing and makeup demineralizing systems. This system consists of a neutralizing tank, recirculation pump, mixer, and pH control for addition of acid or caustic to neutralize the regenerant wastes. The neutralized wastes are then bled at a controlled rate into the makeup supply or discharged to the river.

The pretreatment waste disposal system accepts blowdown and backwash from the clarifier, gravity filters, and carbon filters. This system consists of a compartmented sludge lagoon. The individual compartments can be successively filled and decanted with the decant water drained at a controlled rate into the makeup supply or discharged to the river.

Oily wastes from the turbine room sumps and deluge water are drained into a surge pond followed by an oil/water separator. The separated oil and sludge are transported for offsite disposal and the water is degraded in an oxidation

pond before disposal at a controlled rate into the makeup supply or discharged to the river.

4.4.2.2.10 Ultimate Heat Sink

To remove decay heat from the reactor on shutdown, a cooling system consisting of intake structure, vertical cooling water pumps, traveling screens, trash rake, and gantry crane have been included in plant design. Redundant pumping equipment has also been included. Cooling water will be taken from the Mississippi River.

4.4.2.2.11 Buildings and Other Structures

This section describes the major structures of a HTGR nuclear power station. Table 4-9 lists the safety classifications of these structures. Safety classes are in conformance with present-day nuclear safety criteria.

Prestressed Concrete Reactor Vessel: The PCRV contains and shields the reactor core and the entire primary coolant system, including the steam generators and helium circulators. It functions as the primary coolant system pressure boundary. The complete PCRV is composed of: an internal steel liner acting as a sealing membrane; a thermal barrier and cooling system to limit concrete temperatures;

TABLE 4-9

SAFETY CLASSIFICATION OF STRUCTURES

<u>Structure</u>	<u>Safety*</u> <u>Class 1</u>	<u>Safety*</u> <u>Class 2</u>	<u>Safety*</u> <u>Class 3</u>	<u>No Safety**</u> <u>Class</u>
Reactor Containment Building, Penetrations, and Hatches		X		
Reactor Service Building		X		
Control Building		X		
Penetration Building		X		
Auxiliary Circulator Power Supply Buildings		X		
Diesel Generator Building		X		
Turbine Building				X
Helium Storage Building				X
Acid and Caustic Storage Structure				X
Raw Water Intake Building				X
Reactor Containment Building Interior Structures		X		
Substation Structures				X
Sewage Treatment Plant				X
Water Treatment Building				X
Office and Service Building				X

TABLE 4-9 (Cont)

SAFETY CLASSIFICATION OF STRUCTURES

<u>Structure</u>	<u>Safety*</u> <u>Class 1</u>	<u>Safety*</u> <u>Class 2</u>	<u>Safety*</u> <u>Class 3</u>	<u>No Safety**</u> <u>Class</u>
Auxiliary Boiler House				X
Circulating Water Pumphouse				X
Guard House				X
Warehouse				X

*Also Seismic Category I structures.

**Also nonseismic category structures.

penetrations and closures to provide access to the vessel cavities; and high-strength concrete with bonded reinforcing steel and prestressing systems to provide strength. The entire assembly is mounted on a support structure. The liner, concrete, reinforcing steel, and prestressing systems function as a composite structural system.

Reactor Containment Building: The reactor containment building is a Safety Class 2, Seismic Category I structure which provides a leakage barrier against significant fission product release to the atmosphere following an accident. The reactor containment building allows the atmospheric density in the PCRV to be maintained as required for adequate core cooling following a design basis accident. The concrete structure also provides shielding from fission products which could be airborne within the building under accident conditions.

The reactor containment building is a cylindrical, prestressed concrete structure bearing on sound soil. The foundation mat has conventional steel reinforcing. The cylindrical walls are prestressed with a post-tensioning tendon system in the vertical and horizontal directions. The dome is prestressed utilizing a three-way post-tensioning tendon system. Anchorages for the lower vertical tendon are located in a tendon gallery. Hoop tendons are anchored to three buttresses. The top vertical tendon anchorage and the dome tendon anchorage are located in the ring girder area. For easy accessibility, the PCRV tendon gallery and the reactor containment building tendon gallery have been cross-connected.

The inside surface of the reactor containment building is lined with carbon steel liner plate with stiffeners to ensure a high degree of leak tightness for the containment. Leak chase channels are provided for the bottom liner plate and for inaccessible areas.

The polar crane, with main and auxiliary hooks, will be supported from the vertical building walls.

Reactor Service Building: The Safety Class 2, Seismic Category I reactor service building houses new and used fuel storage facilities and reactor auxiliary systems not located in the reactor containment building.

The primary activity in the reactor service building will be refueling. The reactor will be refueled via the reactor service building through the access door connecting the refueling floor of the reactor containment building to the reactor service building. Both new and spent fuel are handled through this opening. Refueling equipment is normally stored in the reactor service building and will be transported into the containment through the equipment hatch when required.

The fuel storage concrete monolith contains the spent fuel elements. This massive structure comprises the inner core of the reactor service building and is also used for storage of radioactive tools, control rods, and other equipment. The remaining portion of the reactor service building below the refueling floor houses the fuel inspection and sealing facility, equipment service facility, fuel shipping facility, shipping cask transporter parking and service area, and other auxiliary systems.

A crane mounted on the top of the reactor service building makes all lifts necessary for storing fuel in the monolith and transferring fuel to the reactor. Also, along with its auxiliary hoist, this crane performs all necessary maintenance lifts. Fuel is transferred to the reactor in a transfer cask.

The reactor service building, a multistory structure beside the reactor containment building, is structurally independent of the other buildings. The foundation is a reinforced concrete mat on sound soil.

Control Building: This is a Safety Class 2, Seismic Category I structure housing the control room, auxiliary electrical equipment, ventilation equipment, controlled access area, and the reactor plant cooling water system. The following functional areas comprise the control building:

- Control and computer rooms
- Essential switchgear room
- Relay and instrument room
- Battery charging rooms
- Ventilation equipment
- Reactor plant cooling water system equipment

The control building has reinforced concrete floor slabs, walls, and roof. The building is protected from possible missile damage since it contains safety-related equipment.

Interior walls are reinforced concrete including elevator and stairwell enclosures, thus meeting fire resistance criteria. Walls, floor slab, and ceiling around the control access filters and emergency charcoal filters are reinforced concrete for biological shielding.

Penetration Building: The Safety Class 2, Seismic Category I penetration building protects both safety- and nonsafety-related penetrations. The building consists of a tunnel housing electrical control and power cables and valve pits housing main steam line stop valves. It is laid out so that it completely surrounds the reactor containment building thereby protecting the containment penetrations at different locations around the perimeter of the containment structure.

Auxiliary Circulator Power Supply Building: The Safety Class 2, Seismic Category I auxiliary circulator power supply building houses the three auxiliary circulator power supplies. The building is located on the perimeter of the electrical tunnel. Auxiliary circulator power supplies are placed 60 degrees apart within the building. Walls, roof, and mat of this structure are designed to withstand the impact of tornado-generated missiles.

Diesel Generator Building: The Safety Class 2, Seismic Category I diesel generator building houses standby power supplies consisting of three diesel generators for each unit.

The diesel generator building is designed to withstand short-term tornado loading including impact of tornado-generated missiles. Openings are provided with gratings to protect against missiles.

Turbine Building: The turbine building is a nonsafety-class, nonseismic-category structure that contains the turbine generator and other equipment related to the conventional portion of the plant.

The turbine building is a multistory steel-frame structure with a roof of built-up roofing, rigid insulation, and steel

deck supported by roof purlins and steel frames. The side walls are constructed of insulated metal siding. All floors are of reinforced concrete.

The turbine generator pedestal is a massive reinforced concrete structure designed to support the turbine generator with no objectionable deflections. Its natural frequency is above the dynamic vibration frequency of the turbine generator. The turbine generator pedestal is isolated from the turbine building and is supported on adequate subsoil material.

A bridge crane is provided to service the turbine building and has access to the laydown area and the railroad access bay.

Helium Storage Building: This nonsafety-class, nonseismic category structure houses the primary coolant helium storage bottles. The helium storage building is a pre-engineered steel and metal siding structure.

Acid and Caustic Storage Structure: This nonsafety-class, nonseismic category structure provides storage for acid and caustic required for plant operation. This building is a lean-to type structure of steel and metal siding.

Raw Water Intake Building: This nonsafety-class, nonseismic-category structure houses equipment required for supply water from a natural source adjacent to the plant. It is a partially subgrade structure. It includes a pumphouse for raw water pumps, a fire-pump pool, and a screening equipment area.

The bottom floor slab is a reinforced concrete mat bearing on sound soil. Walls are reinforced concrete. A diesel engine, engine housing, pumps, and miscellaneous equipment are also supported by a reinforced concrete floor slab.

Miscellaneous Buildings: The water treatment plant will be outdoors, except for a small laboratory and control building. Also included is a building for office and warehouse space. The buildings will be single-story steel-framed structures with insulated metal siding built on a concrete slab on grade.

4.4.2.2.12 Other Structural Criteria

Foundations: Based on available soils information for the proposed site, it may be necessary to remove a significant amount of existing soil down to an adequate soil bearing stratum in the area of the main plant. If so, a select compacted backfill will be used to replace the removed soil. All significant structures will be supported on reinforced

concrete mat foundations. Other structures and equipment will be supported on reinforced concrete spread footings or pile foundations.

Due to the groundwater level anticipated at the proposed site, extensive dewatering operations will be necessary during construction of the foundations.

Yardwork: The cost estimate includes clearing and grubbing the site, excavation and spoiling of undesirable material, railroad trackwork, permanent plant roads, and fencing. Also included are costs for the construction of two bridge structures over the New River for roadway and railroad.

4.4.3 ADVANCED FOSSIL FUEL TECHNOLOGY - FUTURE DEVELOPMENT

4.4.3.1 Eastern Coal Fluidized-Bed Boilers

Fluidized-bed combustion of coal in a bed of limestone offers the potential for utilizing our country's vast coal resources in an environmentally acceptable manner for cogeneration as well as electric utility power generation. Fluidized-bed combustion is a process which involves the burning of coal particles in a bed of inert solids fluidized by an evenly distributed upward flow of air. Heat is transferred from the bed of solids to heat transfer surfaces located in and above the bed. Combustion takes place between 1,500-1,600 F, which is important for two reasons: (1) the temperature is below the ash fusion point which prevents slagging and related corrosion from low melting sodium-potassium-sulfur compounds, and (2) oxides of nitrogen are minimized by substantially reducing the thermal NO_x production which occurs at higher temperatures. By using a bed of limestone, sulfur from the coal is captured in the bed so that SO₂ in the combustion gas is limited to acceptable levels without recourse to flue gas desulfurization systems.

In addition to offering a potentially sound environmental process for burning coal, the process permits the utilization of low grade coals. Fluidized-bed combustion was developed by the British, primarily to utilize low grade coals. The inherent design of the process, involving low combustion temperatures, allows the use of low rank U.S. coals, which to date have been difficult to burn without encountering environmental and other problems.

A final area of importance is the potential for smaller boiler volumes due to high heat-transfer coefficients for surface located in the bed. These coefficients are in the range of 3-5 times those experienced in convective surfaces of conventional pulverized-coal boilers. This potential

offers a possibility of lower capital investment for the boiler.

The following sections compare conventional plant and fluidized-bed boilers.

4.4.3.1.1 Conventional Cogeneration Plant Boilers

As shown on Drawing No. 12977-EP-2F, located in Appendix B, the total steam generation required for the Geismar cogeneration plant is 9,237,178 lb/hr at 2,415 psia, and 1,000 F. The steam is supplied by two boilers with boiler efficiencies of 86 percent. In contrast to the current typical electric utility boiler, there is no reheat involved.

4.4.3.1.2 Fluidized-Bed Boiler General Specifications

The size, number of boilers, and the steam conditions of atmospheric fluidized-bed (AFB) boilers are the same as conventional boilers. AFB boilers are designed to burn high-sulfur eastern or midwestern coals, for which pulverized-coal firing requires the use of flue gas desulfurization systems to comply with EPA SO₂ new source performance standards. Sulfur dioxide emissions from AFB boilers are controlled by the use of limestone in the bed. In addition, an important economic advantage is realized by using highly coking or slagging coals, which to date have been difficult to burn in conventional boilers. The flexibility of coal purchase possibilities is a very important advantage of AFB technology.

The cogeneration plant is designed to comply with both state and federal regulations. In Louisiana, the federal EPA new source performance standards for fossil fuel fired steam electric generating stations are the limiting regulations. For a coal-fired plant allowable emissions are 0.1 lb/10⁶ Btu heat input for particulate matter, 1.2 lb/10⁶ Btu for SO₂, and 0.7 lb/10⁶ Btu for NO_x. Compliance with particulate emission regulations requires either a hot electrostatic precipitator or a baghouse. Emission of SO₂ is controlled by limestone addition to the bed; NO_x would be inherently low (0.3-0.5 lb/10⁶ Btu) as a result of low combustion temperatures (1,500-1,600 F).

4.4.3.1.3 Boiler Equipment Differences

There are presently no physical examples of large fluidized-bed boilers of the size required for the present cogeneration study. The largest to date is a 300,000 lb/hr demonstration unit sponsored by the U.S. Department of Energy at the Rivesville station of the Monongahela Electric

Power Company. However, there exists a more suitable study for postulating the physical features and relative cost of the atmospheric fluidized-bed boilers in the form of designs developed by the two major manufacturers for another application. The study, titled "Conceptual Design For An Atmospheric Fluidized-Bed Direct Combustion Power Generating Plant," was undertaken by S&W for the Department of Energy under Contract No. EF-77-C-01-2583.⁽²²⁾ It includes AFB boiler designs of the Babcock and Wilcox Company, and Foster Wheeler Energy Corporation and is based on their respective interpretation of the present state of the art.

Although the electric utility application involves reheat, whereas there is none in the cogeneration case, an analogy can be made on the basis of total fuel heat input to the respective boilers. For the electric utility study application, the total fuel heat input is on the order of 5 1/2 billion Btu/hr as compared to slightly more than 10.5 billion Btu/hr for the cogeneration case. However, the latter would be shared by two boilers each with an input of about 5 1/4 billion Btu/hr, or each about 95 percent the size of the examples displayed in the electric utility boiler study.

Expressed in tons of coal per hour, the full-load burning rate per boiler for the electric utility application case is about 180, compared to a cogeneration requirement of 172 per boiler.

The electric utility application study examined the differences between the conventional coal-fired boiler and the fluidized-bed cases in detail. A general impression is obtained from viewing the following drawings selected from the study:

	<u>Base</u>	<u>B&W AFB</u>	<u>FW AFB</u>
	<u>S&W Drawing No. 12977</u>		
Site Plan	EM-1G	EM-1J	EM-1N
Side Elevation	EM-1H	EM-1K	EM-1O
General Arrangement Plan	-	EM-1L	EM-1P
Front Elevation	EM-1I	-	-
Composite (Front Elevation)	-	EM-1M	EM-1Q

Noting the portion of the site plans marked with elongated circles, a comparison of boiler and associated flue gas systems is possible. One of the main attractions of fluidized-bed combustion is that flue gas scrubber (SO₂ removal) equipment is omitted. However, the boiler size reduction frequently attributed to the fluidized-bed concept is largely offset by the greater size area required for related auxiliary systems. This tradeoff is shown in

greater detail on the elevation and plan view drawings listed above. From this comparison the requirements for two such boilers or moderately smaller capacity for cogeneration may be visualized.

Considering the equipment typically included in the scope supplied by the boiler manufacturer, there are many differences. For this study, it should suffice to point out three of the most significant: First, the conventional furnace combustion zone is replaced by a plurality of fluidized beds. In the B&W case, they can be seen on the plan and elevation drawings to include four main beds at each of two elevations and one at a lower elevation, and four carbon burnup beds at one elevation. In the Foster Wheeler case, there are main beds at each of five elevations and a carbon burnup bed at an adjacent lower elevation.

Second, there are no pulverizers or coal burners required for the fluidized-bed boilers. Instead, appropriately sized coal and limestone material is stored in bunkers and fed individually to each of the beds in combination with individually controlled combustion/fluidization air.

Third, in place of a bottom ash removal system, typical for conventional boilers, the fluidized-bed cases require a material letdown system for roughly 50 percent of the total ash and all of the spent limestone accumulated in the beds. Typically, the bed letdown material is received continuously in holding tanks from which it is periodically removed by disposal systems.

4.4.3.1.4 Balance of Plant Differences

With the foregoing in mind, a significant balance of plant difference may be seen. The omission of the flue gas desulfurization facilities (SO₂ removal equipment) is largely offset in site area by larger particulate collectors. Inasmuch as the flue gas from the AFB boilers is devoid of sulfur oxides, the resistivity of the fly ash with respect to electrostatic precipitation is much higher than for the base case wherein the precipitator precedes the sulfur removal. For this reason, B&W elected to use a hot precipitator and Foster Wheeler elected to use a fabric filter (baghouse), both of which are significantly larger than the base case precipitator.

For the AFB cases, notable differences from the conventional systems for preparation and handling of coal and limestone are apparent from the drawings of the electric utility power generation study. They result from the AFB need for finer in-the-yard grinding of the coal (to the final size for burning) than is typical for the conventional plant with pulverizers. The resulting addition of a new crusher house

can be seen on the two site plans. If the cogeneration plant employed fluidized-bed boilers exclusively, although of somewhat greater duty than those required for analogous conventional plants, they would be the only crushers required. Other differences in coal and limestone handling are apparent from the arrangement drawings which indicate that more extensive distributed coal and the limestone bunkering is required for the AFB cases than is typical of a conventional coal-fired boiler plant.

Solid wastes from the AFB boiler cases include dry handling of the fluid bed ash and spent limestone from the bed. These wastes are in contrast to the wet handling of furnace bottom ash and scrubber sludge in the conventional boiler case. The more important aspect is in the tradeoff between the handling problems of the wet scrubber sludge and the comparable quantity of dry spent limestone removed with ash from the beds. The relative cost of the two is covered in another section.

For the most part, the substitution of a fluidized-bed boiler in place of a conventional pulverized coal boiler involves differences in the boiler plant only. However, there are two important additional requirements for a fluidized-bed boiler; namely: (1) the need for a turbine bypass steam system and (2) special capabilities of the electrical auxiliary power systems. The first is needed to remove heat from the submerged tube bundles in the bed in the event of a turbine trip. This requirement is particularly essential to avoid overheating of submerged superheater tube material. The second is the need to accommodate larger horsepower electrical motors than may be typical for a conventional pulverized coal-fired plant. The latter requires a 13.2-kV auxiliary power system in addition to the more typical 4-kV service.

The remainder of the cogeneration plant would be the same as the coal-fired plant described in Section 4.4.1.2.1 and shown on Drawing No. 12977-EP-2F located in Appendix B. The steam output and electric generation would be the same so that water treatment, pumping, feedwater heating, turbine generators, steam, and electrical distribution would be unchanged.

4.4.3.1.5 Boiler Control Flexibility

It must be recognized that there are important fundamental differences in the control facilities required for a fluidized-bed boiler as compared to the conventional boiler. The most obvious is the nature of the fluidized bed as a fuel burning device. In contrast to combustion via burners in one common furnace of the conventional boiler, the AFB beds are in segments. In the examples of the electric power

generation study, the B&W case contained 20 operating segments divided between 1 1/2 boiler beds and 3 1/2 superheating beds, whereas the FW case also had 20 segments, but divided between two boiling beds, two superheating beds, and one reheating bed. In addition to the main beds, both designs included carbon burnup cells in which the collected carryover from the main beds is burned in order to improve overall combustion efficiency. The latter operates at lower fluidization velocity, higher excess air, and higher temperature than the main beds and does not contain submerged heat exchange surfaces other than the containing walls of the bed enclosure. Additional surfaces, including economizers, are included in the flue gas path following the exits from the beds.

Fuel and air to each bed must be controlled independently in order to regulate bed temperature within prescribed limits and be responsive to system demands. Load following is accomplished by cutting segments in and out, supplemented by regulation of bed temperature within limits. Additionally, the total inventory of material in each bed segment must be continuously regulated by extracting material. This letdown of spent limestone and ash from each segment is controlled as a direct function of the total material input to the segment supplemented by automatic correction of departure from normal bed level.

4.4.3.1.6 Cont Development and Potential

The problems just discussed leave some concern as to whether the challenging aspects of fluidized-bed combustion will be adequately offset by its advantages. It must be recognized that FB is not yet a mature commercial entity and that major improvements in aspects of the designs will evolve in time. With this expectation, the major organizations which are currently supporting AFB development programs associated with electric power generation are: Department of Energy, (DOE), Environmental Protection Agency (EPA), Electric Power Research Institute (EPRI), Tennessee Valley Authority (TVA), and the State of Ohio. DOE is the lead organization in the United States for funding AFB combustion; it is presently sponsoring two commercial plant conceptual design studies, cofunding with TVA a conceptual design for a 200-MW demonstration AFB plant, and funding the 30-MW Rivesville program. Table 4-10 summarizes the status of these programs.

EPRI is sponsoring several development programs designed to provide basic engineering design data in support of the DOE program. In addition to transport phenomena studies, EPRI is supporting the B&W 6-foot x 6-foot process development facility which recently started operation.

TABLE 4-10
DEPARTMENT OF ENERGY
ATMOSPHERIC FLUIDIZED-BED PROJECTS

<u>Project</u>	<u>Contractor</u>	<u>Size</u>	<u>Objective</u>	<u>Status</u>
Rivesville	Pope, Evans, & Robbins	30 MW	To demonstrate AFB plant on utility system	In the testing program
Utility Commercial Plant Conceptual Design	Stone & Webster	600 MW	To develop a commercial size utility plant design burning high sulfur eastern coal	Completed December 1977
Utility Commercial Plant Conceptual Design	Burns & Roe	600 MW	To develop a commercial size utility plant design burning noncompliance western coal	Completed March 1978
Utility Demonstration Plant	TVA	200 MW	To demonstrate AFB plant on a commercial scale	Phase I AFB boiler concep. design completed. Phase II detailed design to be undertaken in 1978

The State of Ohio is supporting four AFB projects as a means of lessening the state's dependence on gas and oil and promoting the use of Ohio high sulfur coal. One of these projects is a 30-MW AFB boiler at Columbus and Southern Ohio Electric Company, which is scheduled for startup in 1979.

DOE is planning to support one or more 200-MW demonstration plants in the near future: The present timetable for operation of these units is anticipated in 1982 or 1984. TVA also is planning a 200-MW plant in the same time frame. Both DOE and TVA anticipate commercial operation of large utility plants (600-800 MW) using AFB boilers by the late 1980's or early 1990's.

Current literature applicable to AFB technology, and specifically the utility industry, is summarized below:

- Preliminary Evaluation of Atmospheric Pressure Fluidized-Bed Combustion Applied to Electric Utility Large Steam Generators, February 1976, available from EPRI.
- Part IV. Technical Notes for the Conceptual Design for an Atmospheric Fluidized-Bed Direct Combustion Power Generating Plant, Stone & Webster Engineering Corporation, to be available through NTIS.
- The Conceptual Design of an AFBC Electric Power Generating Plant, December 1977, available from Burns and Roe, Incorporated.
- Application of Atmospheric Fluidized-Bed Combustion for Electric Power Generation, December 1977, available from Babcock & Wilcox Company.
- Conceptual Design of Foster Wheeler Energy Corporation Atmospheric Fluidized-Bed Steam Generator, December 1977, available from FW.
- Conceptual Design of a 570-MW Atmospheric Fluidized-Bed Steam Generator, December 1977, available from Combustion Engineering, Incorporated.

4.4.3.2 Eastern Coal Gasification

This section defines and develops three concepts utilizing gasification of eastern coal to provide the energy source for a cogeneration plant. The alternatives outlined in this section are:

- Burning coal-derived fuel gas in conventional boilers to generate steam.

- Burning coal-derived fuel gas in gas turbines to generate both electricity and steam.
- Utilizing coal-derived fuel gas in fuel cells to generate both electricity and steam.

A total of six coal gasification schemes were analyzed:

1. Air-blown coal gasification process with conventional gas-fired boiler.
2. Oxygen-blown coal gasification process with conventional gas-fired boiler.
3. Air-blown coal gasification process utilizing gas turbines with no limit on electrical generation.
4. Air-blown coal gasification process utilizing gas turbines with a limit on electrical generation.
5. Air-blown coal gasification process utilizing fuel cells with no limit on electrical generation.
6. Air-blown coal gasification process utilizing fuel cells with a limit on electrical generation.

In all cases, the basic requirement is to provide the steam to meet the projected 1985 demand. Electric power generation is the variable and is either left to seek its own level, or limited to approximate the output of the fossil fuel-fired cogeneration plant. Later in this section each coal gasification scheme is economically evaluated to determine the arrangement most adaptable to the cogeneration concept.

The main advantage of the coal gasification process is that sulfur is converted to hydrogen sulfide gas, which can be removed by commercially available processes, and ultimately recovered as elemental sulfur. This eliminates the need for precipitators, and flue gas desulfurization equipment.

Because of its commercial availability, the Lurgi coal gasification process was selected as the basis for this study. Although it is not the optimum coal gasification process of those listed, the general conclusions drawn by this study would remain the same if one of the other type coal gasifiers were substituted. Illinois No. 6 coal was utilized as the common fuel for all schemes because data for this coal were readily obtainable from various Electric Power Research Institute Reports already published. The properties of Illinois No. 6 coal are shown in Table 4-11, and can be compared to those of Alabama coal reflected in

Table 4-5. It was assumed that the delivered coal would be washed and sized to 1 1/2 inch x 1/4 inch.

TABLE 4-11

COAL CHARACTERISTICS

Illinois No. 6

<u>Proximate Analysis</u>	<u>Wt %</u>
Moisture	4.2
Ash	9.6
Fixed Carbon	52.0
Volatile Matter	<u>34.2</u>
TOTAL	100.0
<u>Ultimate Analysis DAF Coal</u>	<u>Wt %</u>
Carbon	77.26
Hydrogen	5.92
Oxygen	11.14
Nitrogen	1.39
Sulfur	<u>4.29</u>
TOTAL	100.00
<u>Heating Value (as received)</u>	<u>Btu/lb</u>
Higher (HHV)	12,235
Net (LHV)	11,709
HHV (MAF Basis)	14,194

The coal gasifiers described herein represent existing commercial or near commercial technology. Current commercial large-scale processes are Lurgi, Koppers-Totzek, and Winkler. Improved processes presently under development include the British Gas Corporation slagging version of the Lurgi gasifier, the Shell-Krupp Koppers pressurized entrained bed gasifier, the Texaco gasifier, the Foster-Wheeler gasifier, and the Babcock & Wilcox gasifier. Table 4-12 shows the size, capacity, and performance of various gasifier systems. The three large-scale processes and the developmental Texaco process are discussed in the following sections.

Lurgi Process: The only commercial pressurized gasifier at the present time is the Lurgi unit. None, however, have been installed in the United States. A 170-MW combined-cycle plant using the Lurgi air-blown system was built in Lunen, West Germany, in 1973.

TABLE 4-12
SIZE, CAPACITY, AND PERFORMANCE OF VARIOUS GASIFIERS

	<u>Lurgi</u>	<u>Lurgi</u>	<u>Winkler</u>	<u>Winkler</u>	<u>Koppers-Totzek</u>	<u>Texaco</u>	<u>Texaco</u>
Type Gasifier	Fixed	Fixed	Fluidized	Fluidized	Entrained	Entrained	Entrained
Oxygen or Air	Oxygen	Air	Oxygen	Air	Oxygen	Oxygen	Air
Pressure, Atm.	30	20	1	1	1	20-80	20-80
Gas, Btu/hr 10 ⁶	600	450	750	500	680	-	-
HHV, Btu/std cu ft	290-310	160-180	270-290	115-125	270-290	250-270	105-115
Temperature, °F	900-1,200	900-1,200	1,350-1,500	1,350-1,500	2,000-2,700	2,000-2,700	2,000-2,700
Coal Size, in	1/4-1 1/2	1/4-1 1/2	0-3/8	0-3/8	70% - 200 mesh	NA	NA
Coal - Tons/Day	780	587	1,000	700	850*	-	-
Lb Air or Oxygen/ Lb Coal	0.3-0.4	1.3-1.9	0.5	2.5	0.6-0.8	NA	NA
Lb Steam/Lb Coal	1.0-1.5	0.7-0.8	0.3	0.2	0.1-0.5	0.6-0.9 (water)	0.6-0.9 (water)
Turndown, % of max cap	25	25	35	35	65(1)-35(2)	50 per gasifier	50 per gasifier
Gasifier ID, ft	12	12	18	18	11	NA	NA
Ash Removal	Dry	Dry	Dry	Dry	Slag	Slag	Slag

(1)Two burners.

(2)Four burners.

NOTE: NA - Not available for publication.

Data for Lurgi, Winkler, and Koppers-Totzek based on Chemical Engineering Progress, June 1977, p 86.

The Lurgi gasifier operates between 350 and 450 psig, requires sized coal (1 1/2 inch x 1/4 inch), and can utilize either oxygen or air as the oxidant. Noncaking coals are handled most easily, although tests indicate that caking coals can also be processed. To date there is little commercial experience with caking coals.

Koppers-Totzek Process: This process operates at a pressure slightly above atmospheric, uses oxygen as the oxidant, and is capable of gasifying all types of coal. Air-blown operation is technically feasible, but thermally inefficient because large volumes of gas are generated at high temperatures.

For combined-cycle system application, the atmospheric-pressure gasification requires that the gas be compressed. A blower could be utilized to boost the effluent gas to the slightly higher pressure required for operating fired boilers or fuel cells.

Winkler Process: The Winkler coal gasification system is a fluidized-bed atmospheric pressure process. The gasifier has been operated successfully at 1.5 atmospheres and future development calls for testing United States coals up to 15 atmospheres in a proposed 10 ton/day pilot plant. Either air or oxygen can be used as an oxidant.

Winkler units can gasify solid fuels ranging from lignite to moderately caking bituminous coal. It is expected that bituminous coals with free-swelling indices of less than four can be fed without pretreatment. Carbon utilization is reduced by 15-30 percent of unconverted carbon contained in the char. If the char is utilized in a coal-fired boiler, the overall efficiency of the process can be increased.

Texaco Coal Gasification Process: The Texaco coal gasifier is high on the list for consideration in advanced technology coal gasification processes and is currently being studied under several governmental and industrial contracts. It has been successfully tested on various coals in a 15 ton/day pilot plant at Montebello, California. A 160 ton/day pilot plant is scheduled for startup in West Germany during 1978.

The process is based on partial oxidation using a coal/water or coal/oil slurry feed with oxygen or air. It is capable of operating at pressures in excess of 80 atmospheres. The gasifier is the entrained type utilizing a refractory lined vessel similar to those used in commercial oil gasification plants.

Virtually any type coal can be gasified in the Texaco gasifier to produce low-or-medium-Btu gas. The slurry feed consisting of ground coal mixed with water or oil is pumped

into the gasifier, together with air or oxygen. The slurry contains 50-60 percent solids. The slurry and air or oxygen are mixed in a special burner and fed to the gasifier. Within the gasifier, partial oxidation takes place under closely controlled conditions. The gaseous products are first cooled in a waste heat boiler or by direct water quench and then scrubbed with water to reduce the particulate matter in the gas. Soot from the scrubber is recycled to the gas generator. The effluent gas then passes through a hydrogen sulfide removal system to produce a clean boiler fuel.

The Texaco gasifier has several distinct advantages, namely:

- Simplicity
 - No moving parts
 - Single stage
- Feedstock flexibility
 - Virtually all U.S. coals
 - Coal/water or coal/oil slurries
- Absence of tar by-product reduces cleanup and downstream processing.
- Water slurry feed increases safety and reliability. This also serves to minimize aqueous effluent treatment requirements.
- Ability to operate at high pressure.
- Status of development
 - Several years' pilot plant (15 TPD) operating experience
 - Operating results on 160 TPD German unit expected in 1978

Accessory Process Equipment: Major equipment and processes required to complete the Lurgi coal gasification systems discussed in this report are:

- Acid gas (hydrogen sulfide) removal units. The Allied Chemical Selexol Process, which is commercially available, has been selected.
- Sulfur recovery unit. The well-established Claus process has been selected.
- Process condensate treating to remove phenols and ammonia from the water scrubbing liquor. The Lurgi Phenosolvan process removes phenols, and ammonia is recovered by further processing.

- Low-level heat recovery to produce power. A Rankine cycle utilizing isobutane as the working fluid has been selected.
- Gas turbines operating at 1,950 F inlet temperature. These turbines are presently available, although further development work is also in progress for operation at yet higher temperatures.

4.4.3.2.1 Eastern Coal Gasification with Conventional Boilers

This scheme considers both the air-blown and oxygen-blown moving-bed coal gasification systems in conjunction with a cogeneration plant using coal-derived fuel gas-fired boilers to produce steam for consumers. Coal-derived fuel gas provides the heat input to the boilers shown on Drawing No. 12977-EP-2F located in Appendix B. Major changes within the cogeneration portion of the plant to suit firing of coal-derived fuel gas include modifying the boilers and their related accessory equipment, deletion of the precipitators and scrubbers, and increasing the capacity of the coal handling facilities and water treating system. For a description of the cogeneration portion of the plant refer to Section 4.4.1.2.

Block-type flow diagrams for these plants are shown on Drawings No. 12977-EP-2R and 2S in Appendix B. These drawings reflect the various estimated material flows for the air-blown and oxygen-blown gasifiers, respectively. The required boiler feedwater, cooling water, and wastewater treatment are provided by increasing the facilities within the cogeneration plant.

In addition to the electric generation from the cogeneration plant, the coal gasification plant also provides a net output of 122.5 MW and 124.5 MW for the air and oxygen gasifiers, respectively.

A coal feed rate of 16,040 and 16,294 tons/day for air- and oxygen-blown gasifiers, respectively, is needed to provide sufficient coal fuel gas for the two 4,700,000 lb/hr boilers in the cogeneration plant.

4.4.3.2.2 Eastern Coal Gasification with Combined Cycle Gas Turbines

This section considers the use of a gas turbine combined cycle in the cogeneration plant. Clean fuel gas generated in a Lurgi coal gasification system provides the fuel for steam and power generation. Because the combined cycle is inherently a primary producer of electricity rather than

steam, two separate schemes were developed and evaluated. In both cases, the prime objective was the generation of steam to meet the projected 1985 requirements. This permitted direct comparison with the other types of cogeneration plants.

A review of the Electric Power Research Institute's report on coal gas cleaning indicates that a somewhat higher thermal efficiency is obtained for an air-blown Lurgi gasifier than with an oxygen-blown unit⁽²⁴⁾. The evaluation of the two schemes proceeded with the air-blown gasifier rather than the oxygen-blown based on this information. A summary of thermal efficiencies, not reproduced herein, is shown in Table 4-8A of that EPRI report.

The first scheme, referred to as Alternate A, utilizes the hot turbine effluent to generate the required steam with no limit on the resulting power generated. The second scheme, Alternate B, limits the net electric generation to 352 MW, which in turn limits the flow of turbine effluent and corresponding waste heat recovery, and necessitates the addition of fuel gas-fired boilers to meet the steam demand. The electrical output was established to approximate the output of the fossil fuel-fired cogeneration plants to permit economic evaluation and comparison.

The arrangement of Alternate A, along with the steam flows, coal requirements, feedwater flow, and power generation, are shown on Drawing No. 12977-LP-2T located in Appendix B. The clean fuel gas is burned in a combustor with excess air. The combustion products are quenched with additional air to about 1,950 F before being fed into the gas turbines of the combined cycle cogeneration plant. Each gas turbine drives an air compressor and an electric generator.

Turbine effluent gas at approximately 1,000 F flows to a waste heat recovery section where steam is generated at three levels: 970, 690, and 290 psia to meet users' demands. In addition to users' demands, 690 psia steam is generated to supply the gasifier steam requirements. Additional steam at 290 psia is also generated for deaerator heating. The process side-turbine effluent leaves the waste heat recovery section as stack gas at about 320 F.

Net electrical generation is 1854 MW based on the summation of the gross output of the gas turbine generators plus the tar combustion generators, less the power required for the gasifier air compressor and all other coal gasification plant and cogeneration plant auxiliary loads.

The A scheme requires a coal feed of 2,276,569 lb/hr (27,319 ton/day) to generate the clean coal-derived fuel gas required for the gas turbine cycle.

Drawing No. 12977-EP-2U, located in Appendix B, shows an overall block diagram with flows for Alternate B using the same Lurgi air-blown gasification system, but with the addition of coal-derived fuel gas-fired boilers to generate steam.

Gas turbine effluent first passes through a heat recovery section where a portion of the required 690 psia superheated steam is generated. This gas stream, which consists of combustion products as well as an appreciable amount of oxygen, is cooled from 1,000 F to approximately 600 F. The high oxygen content of this steam supplements the combustion air to the fuel gas-fired boilers.

The steam generation section consists of gas-fired boilers which generate steam at 970, 690, and 290 psia. As with Alternate A, steam is generated to meet the export demands of the users, and the internal requirements of the gasifiers and the deaerator.

The electric output of the plant is generated by the gas turbine generators and the tar combustion unit. After allowance for auxiliary power, the net generation does not exceed the required 352 MW.

A feed flow of 1,291,487 lb/hr (15,498 ton/day) of coal is required to generate sufficient clean coal-derived fuel gas to operate the combined cycle and provide fuel for the boilers. Boiler fuel has a higher heating value of 2,977 Btu/lb (177 Btu/SCF).

4.4.3.2.3 Fuel Cell with Coal Gasification

Fuel cells combine fuel, usually hydrogen gas and oxygen (supplied either as air or oxygen gas), electrochemically to produce direct current electricity. A simplified diagram of the basic principle of the fuel cell is shown on Drawing No. 12977-EP-2X located in Appendix B.

Units of several kW capacity, operating on hydrogen and oxygen, have been used for military and space applications. Development programs for commercialization are in progress, but fuel cells have not yet demonstrated adequate endurance and low enough cost for commercial applications. Factors hindering development are the high cost of low temperature cells and difficulty in obtaining materials suitable for high temperature cells. The types of fuel cells that are being developed and are most likely to be considered for commercial use are the phosphoric acid cell and the molten carbonate cell. These two types of cells and their application are discussed in the next paragraphs.

Phosphoric Acid Cell: A 1-MW direct-current phosphoric acid cell has been operated using carbon monoxide and hydrogen gas produced by the naphtha steam reforming process. An inverter converts the direct current to alternating current. Investigation of this cell has been sponsored by various utility companies and by United Technologies Corporation (UTC).

In 1978, a 4.8-MW phosphoric acid cell is to be delivered to Con Edison in Manhattan for operation on naphtha fuel. The naphtha will be steam reformed to produce a gas that will be reacted in a CO converter to reduce the CO content to 1-2 percent. The object is to obtain a fuel cell feed gas that has a maximum hydrogen concentration since hydrogen is the reactive component in the fuel cell.

About 80 percent of the hydrogen in the feed gas is consumed in the fuel cell and the unreacted hydrogen and other gases are purged and used as a fuel in the naphtha reformer. Waste heat is recovered as steam.

The phosphoric acid cell operates in a temperature range of 300-375 F, limiting the pressure of the waste heat steam to 15-60 psia. This pressure limitation prohibits its use in a cogeneration plant, which requires steam at pressures from 290 to 970 psia.

Molten Carbonate Fuel Cell: The molten carbonate fuel cell has been run on a small scale in stacked units of 1 and 1 1/2 kW. It is expected that demonstration units in megawatt size will probably be available in the early 1980's. A study by UTC and Burns & Roe evaluated a conceptual design for a molten carbonate fuel cell power plant using gas from a low Btu coal gasifier. The proposed system comprised:

- U-gas process fluidized-bed air-blown gasifier (under development by Institute of Gas Technology) to produce fuel gas.
- Iron oxide system (under development by Morgantown Energy Research Center) to remove sulfur from the gas.
- Molten carbonate cell (under development) to produce electric power.
- Steam bottoming cycle to produce electric power.

The overall efficiency of this system (coal pile to busbar) is approximately 49 percent with two-thirds of the gross ac power being generated by the fuel cell and one-third

supplied by the bottoming cycle. The estimated installed cost for a 635-MW plant is \$595/kW.

The molten carbonate cell operates at 1,200 F and can generate 2,400 psia steam, making it suitable for the cogeneration plant. About 36 percent of the energy in the coal appears as electricity and 27 percent as high-quality steam. The hot exhaust gas, similar to high-temperature, high-pressure combusted air is utilized by waste heat recovery. (Molten carbonate fuel cells have not yet been run on gas derived from coal.)

The status and characteristics of the phosphoric acid cell and the molten carbonate cell are outlined in Table 4-13.

TABLE 4-13

CHARACTERISTICS & STATUS OF
PHOSPHORIC & MOLTEN CARBONATE FUEL CELLS

	<u>Phosphoric Acid</u>	<u>Molten Carbonate</u>
Technology Generation	First	Second
Status	Demonstration	Developmental
Module Size, MW	4.8	Not Developed
Reactant Gas	Hydrogen	Hydrogen & Carbon Monoxide
Heat Rate, Btu/kWh	9,300	7,500 (Goal)
Operating Temperature, F	300-375	1,200
Operating Pressure, psia	50	100-150
Projected Installed Cost, \$/kW	250	335-465
Sulfur Tolerance, Max. PPM H ₂ S	200	Less than 10
Cell Endurance Goal, Hours	40,000	40,000

Fuel Cell Application: This section covers two schemes for application of the fuel cell in a cogeneration plant. In both cases, clean coal-derived fuel gas from a Lurgi coal gasification system is used as the fuel for a cell which generates electricity and provides waste heat for generation of steam. Waste heat in a fuel cell results from the inefficiency of converting fuel heating value to electrical energy. Steam for the projected 1985 industrial requirements is produced in each case.

The first scheme utilizes fuel cell waste heat to generate the steam with no limitation on the amount of electric power generated. The arrangement of this system is shown on Drawing No. 12977-EP-2V located in Appendix B. Required

coal feed to the gasifier is 3,065,417 lb/hr (36,785 ton/day).

The second scheme differs by limiting the net electric generation to 352 MW, which is the same power output as the fossil fuel-fired plant. The steam demand, which cannot be met by available waste heat recovery alone, requires that supplemental coal-derived fuel gas-fired boilers be installed. A block-type diagram for this plant is shown on Drawing No. 12977-EP-2W located in Appendix B. Feed rate to the gasifier of 1,251,750 lb/hr (15,021 ton/day) provides the gas for the fuel cell and boilers.

Tables 4-14 and 4-15 indicate projected development dates and cost and performance parameters for fuel cell systems.

TABLE 4-14

FORECAST OF FUEL CELL DEVELOPMENT

Year	TYPE COMMERCIAL OPERATION		
	Baseload Generation	Peak-load Generation (4 hr or less per day)	Intermediate Load Generation (daily cycling)
1980-1985	Fuel Cell/Integrated Coal Gasifier	Fuel Cell-Naptha	Hydrocarbon Fuel Cells (1st and 2nd generation)

Source: U.S. Energy Research and Development Agency. Comparing New Technologies for the Electrical Utilities. Draft ERDA-6-141, December 1976.

TABLE 4-15

PREDICTED COST & PERFORMANCE PARAMETERS
FOR FUEL CELL POWER SYSTEM

	Earliest Year <u>On-line</u>	Net Conversion <u>Efficiency %</u>	Capital Costs* <u>\$/kW (1975 Dollars)</u>
Base-Load <u>Generation</u>			
Molten Carbonate Fuel Cell	1987	50	335 - 465
Peak-Load <u>Generation</u>			
Fuel Cell- Naphtha	1982	37	205 - 265
Intermediate <u>Load Generation</u>			
Molten Carbonate Fuel Cell	1987	50	335 - 465

*Capital costs do not include interest during construction
or provisions for inflation.

Source: U.S. Energy Research and Development Agency.
Comparing New Technologies for the Electrical
Utilities. Draft ERDA-6-141, December 1976.

SECTION 5

COST ESTIMATES

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SECTION 5
COST ESTIMATES

This section presents order-of-magnitude cost estimates for each type of cogeneration plant discussed in the previous section. The estimates include the cost for engineering, design, and construction. Fossil fuel plants (Alabama and Wyoming coal and No. 6 oil fired) and nuclear plants (CNSS and HTGR steamer) are costed for both the Orange and Geismar sites. The future advanced technology plants (fluidized-bed boiler and plants utilizing coal gasification) are costed for the Geismar site only.

In addition to the direct costs, each estimate includes distributables and indirect costs and an allowance for indeterminates. These are defined as follows:

- Indirects: Those costs, including salaries, expenses, overhead, payroll taxes, and fee, associated with the architectural-engineer's (AEs) engineering and design activities including all support services.
- Distributables: Those field costs associated with the operation of construction management field offices and support of direct construction activities. This includes both "temporary services," manual labor, and field-supervisory nonmanual labor with associated benefits, payroll taxes, insurance, expenses, and premium pay. Also included are materials and equipment associated with the construction facilities, such as utilities.
- Allowance For Indeterminates: This is a contingency figure provided for unknowns and is affected by the type of estimate and engineering information available.

For conceptual estimates, the amount allowed for each of these items is usually a percentage established from previous projects of similar nature.

The estimates were prepared and are presented according to accounts established by the Federal Power Commission.

The estimates for the cogeneration plants do not include items which each user must provide to permit receipt of electric power and steam and the return of condensate to the cogeneration plant. Depending on existing facilities at each user's plant, these items may include the following:

- Condensate return pumps
- Condensate storage tank

- Steam and condensate piping, including valves, insulation, pipe supports, and pipe-supporting structures from the plant property line
- Pressure reducing stations
- Step-down transformers with associated switching and protective equipment
- Subdistribution within the user's plant
- Steam and electric metering
- Instrumentation.

Also excluded from any of the cogeneration plant cost estimates are:

- Cogeneration plant land costs, including rights-of-way
- Land costs for steam and electric distribution systems
- Escalation during construction (accounted for in plant evaluation)
- Licensing effort
- Environmental impact statement preparation
- Public presentations
- Relocation of existing underground services
- Relocation of existing railroad spurs
- Relocation of existing above-ground structures
- Spare parts
- Dismantling of the cogeneration plant at the end of its useful life.

5.1 ORANGE SITE

5.1.1 FOSSIL FUEL PLANTS - CURRENT TECHNOLOGY

Order-of-magnitude cost estimates for No. 6 fuel oil-, Alabama coal-, and Wyoming coal-fired plants were developed by obtaining current market prices for major equipment and systems and utilizing existing cost data for the remainder of the plant. These estimates are shown in Tables 5-1 through 5-3.

TABLE 5-1

COST ESTIMATE FOR
NO. 6 OIL-FIRED COGENERATION PLANT
AT ORANGE, TEXAS

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	6,031
Waste Treatment	868
Steam and Condensate Distribution System	10,303
Electric Distribution System	355
Turbine Building	2,493
Screenwell Structure	526
Water Treatment Plant	1,000
Office and Shops	261
Warehouse and Miscellaneous Structures	207
Boiler Plant Equipment	96,866
Open Boiler Structure	5,949
Oil Handling Facility	8,097
Turbine Generator Unit	19,574
Electrical Accessories	12,025
Miscellaneous Power Plant Equipment	1,898
Substation and Switchgear Station	156
Substation and Switchgear Station Equipment	<u>3,698</u>
 TOTAL DIRECT COSTS	 \$170,307
 Distributables and Indirects	 54,498
Allowance for Indeterminates	<u>22,481</u>
 TOTAL	 \$247,286

*In January 1978 dollars.

Each plant consists of two 1,800,000 lb/hr boilers which generate 3,441,382 lb/hr of 2,415 psia, 1,000 F steam and three steam turbine generators which produce a gross output of 185.3 MW.

TABLE 5-2

COST ESTIMATE FOR
ALABAMA COAL-FIRED COGENERATION PLANT
AT ORANGE, TEXAS

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	7,184
Waste Treatment	868
Steam and Condensate Distribution System	10,303
Electric Distribution System	355
Turbine Building	2,493
Screenwell Structure	526
Water Treatment Plant	1,000
Office and Shops	261
Warehouse and Miscellaneous Structures	207
Boiler Plant Equipment	112,756
Open Boiler Structure	5,949
Coal Handling Facility	22,277
Turbine Generator Unit	19,574
Electrical Accessories	12,025
Miscellaneous Power Plant Equipment	1,898
Substation and Switchgear Station	156
Substation and Switchgear Station Equipment	<u>3,698</u>
 TOTAL DIRECT COSTS	 \$201,530
 Distributables and Indirects	 64,490
Allowance for Indeterminates	<u>26,600</u>
 TOTAL	 \$292,620

*In January 1978 dollars.

TABLE 5-3

COST ESTIMATE FOR
WYOMING COAL-FIRED COGENERATION PLANT
AT ORANGE, TEXAS

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	7,184
Waste Treatment	868
Steam and Condensate Distribution System	10,303
Electric Distribution System	355
Turbine Building	2,493
Screenwell Structure	526
Water Treatment Plant	1,000
Office and Shops	261
Warehouse and Miscellaneous Structures	207
Boiler Plant Equipment	114,389
Open Boiler Structure	5,949
Coal Handling Facility	22,277
Turbine Generator Unit	19,574
Electrical Accessories	12,025
Miscellaneous Power Plant Equipment	1,898
Substation and Switchgear Station	156
Substation and Switchgear Station Equipment	<u>3,698</u>
TOTAL DIRECT COSTS	\$203,163
Distributables and Indirects	65,012
Allowance for Indeterminates	<u>26,818</u>
TOTAL	\$294,993

*In January 1978 dollars.

5.1.2 NUCLEAR PLANTS (ORANGE) - ADVANCED TECHNOLOGY UNDER DEVELOPMENT

5.1.2.1 Consolidated Nuclear Steam System

This order-of-magnitude estimate was prepared assuming an nth-of-a-kind unit using the cost estimate contained in Babcock & Wilcox's report (see Table 5-4).⁽¹⁹⁾ Equipment and systems were deleted to adapt the electric generating plant proposed by B&W to a cogenerating plant (see Table 5-5). Costs were escalated to raise the September 1976 cost level to January 1978. Equipment and systems were added to convert the plant to cogeneration (see Table 5-6).

TABLE 5-4

COST ESTIMATE, PART I (B&W CNSS)
CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT
AT ORANGE, TEXAS

	Direct Costs* (\$ x 1,000)
Land and Land Rights	380
Special Material	---
Structural and Site Facilities	48,967
Reactor Plant Equipment	64,121
Turbine Plant Equipment	48,300
Electric Plant Equipment	13,220
Miscellaneous Plant Equipment	4,536
Construction Facilities and Equipment	11,533
Engineering Services	31,035
Other Costs	<u>9,285</u>
SUBTOTAL	\$ 231,377
Contingency (10%)	23,138
SUBTOTAL	\$ 254,515
Indirect Costs	<u>53,346</u>
TOTAL	\$ 307,861

*In September 1976 dollars.

TABLE 5-5

COST ESTIMATE, PART II (ESCALATION AND DEDUCTIONS)
 CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT
 AT ORANGE, TEXAS

	Direct Costs*
	<u>(\$ x 1,000)</u>
Cost Estimate, Part I (Table 5-4)	307,861
<u>Deductions*</u>	
Land and Land Rights	380
Construction Facilities and Equipment	11,533
Engineering Services	31,035
Other Costs	9,285
Contingency (10%)	23,138
Indirect Costs	<u>53,346</u>
TOTAL DEDUCTIONS*	\$ <u>128,717</u>
TOTAL COST*	\$ 179,144
Escalated Cost (9%) **	195,267
<u>Deductions**</u>	
Condenser Equipment	2,500
Circulating Water System	2,050
Circulating Water Equipment	450
400-MW Turbine Generator	25,900
400-MW Substation	<u>3,150</u>
TOTAL DEDUCTIONS**	\$ <u>34,050</u>
TOTAL (Modified CNSS - 1 Unit)**	\$ 161,217

*In September 1976 dollars.

**In January 1978 dollars.

TABLE 5-6

COST ESTIMATE, PART III (SUMMARY)
FOR CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT
AT ORANGE, TEXAS

	Direct Costs* <u>(\$ x 1,000)</u>
CNSS Modified (Table 5-5)	161,217
Yardwork	3,297
Waste Treatment	---
Steam and Condensate Distribution System	10,303
Electrical and Distribution System	355
Turbine Building	---
Screenwell	---
Water Treatment	---
Offices and Shops	---
Warehouses	188
Reactor Structure	---
Reactor Plant	---
Turbine Generator Unit	4,500
Electrical Accessories	2,316
Miscellaneous Power Plant Equipment	---
Substation Equipment	1,044
Guard House	775
Reboiler	4,444
Superheater	17,285
Fuel Oil System	1,336
Cooling Towers	<u>4,454</u>
 TOTAL DIRECT COSTS	 \$ 211,514
Indirects	57,400
Distributables	69,300
QA/QC	8,000
Allowance for Indeterminates	<u>34,586</u>
 TOTAL	 \$ 380,800

*In January 1978 dollars.

5.1.2.2 High Temperature Gas Reactor Steamer

The order-of-magnitude estimate for the high temperature gas reactor was prepared assuming an nth-of-a-kind unit. Costs were developed utilizing existing in-house data and information obtained from General Atomic Company.⁽²¹⁾

The cost estimate is shown on Table 5-7.

TABLE 5-7

COST ESTIMATE FOR HIGH TEMPERATURE GAS-COOLED REACTOR AT ORANGE, TEXAS

	Direct Costs* (\$ x 1,000)
Yardwork	6,700
Control Building	11,124
Turbine Building	5,910
Administration Building	1,160
River Water Intake Structure	580
Miscellaneous Buildings and Structures	2,800
Auxiliary Building	1,510
Reactor Service Building	10,025
Reactor Containment Building	18,750
Reactor Plant Equipment	105,310
Turbine Generator Unit	22,603
Electrical Accessories	29,400
Miscellaneous Power Plant Equipment	3,702
Substation and Switching Station	3,000
Steam and Condensate Distribution System	10,303
Electrical Distribution System	355
TOTAL DIRECT COSTS	\$ 233,232
Indirects	55,610
Distributables	73,416
QA/QC	10,495
Allowance for Indeterminates	37,247
TOTAL	\$ 410,000

*In January 1978 dollars.

5.2 GEISMAR SITE

5.2.1 FOSSIL FUEL PLANTS

Cost estimates for No. 6 fuel oil-, Alabama coal-, and Wyoming coal-fired plants were developed by obtaining current market prices for major equipment and systems and utilizing existing cost data for the remainder of the plant. These estimates are shown on Tables 5-8 through 5-10.

TABLE 5-8

COST ESTIMATE FOR
NO. 6 OIL-FIRED COGENERATION PLANT
AT GEISMAR, LOUISIANA

	Direct Costs* (\$ x 1,000)
Yardwork	8,406
Waste Treatment	1,325
Steam and Condensate Distribution System	84,091
Electric Distribution System	2,535
Turbine Building	3,530
Screenwell Structure	952
Water Treatment Plant	1,237
Office and Shops	324
Warehouse and Miscellaneous Structures	256
Boiler Plant Equipment	217,812
Open Boiler Structure	20,392
Oil Handling Facility	16,366
Turbine Generator Unit	47,707
Electrical Accessories	23,827
Miscellaneous Power Plant Equipment	4,181
Substation and Switchgear Station	195
Substation and Switchgear Station Equipment	<u>4,999</u>
TOTAL DIRECT COSTS	\$ 438,135
Distributables and Indirects	140,203
Allowance for Indeterminates	<u>57,834</u>
TOTAL	\$ 636,172

*In January 1978 dollars.

Each plant consists of two 4,700,000 lb/hr boilers which generate 9,237,178 lb/hr of 2,415 psia, 1,000 F steam and four steam turbine generators which produce a gross output of 448.8 MW.

TABLE 5-9

COST ESTIMATE FOR
ALABAMA COAL-FIRED COGENERATION PLANT
AT GEISMAR, LOUISIANA

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	8,089
Waste Treatment	1,325
Steam and Condensate Distribution System	84,091
Electric Distribution System	2,535
Turbine Building	3,530
Screenwell Structure	952
Water Treatment Plant	1,237
Office and Shops	324
Warehouse and Miscellaneous Structures	256
Boiler Plant Equipment	254,080
Open Boiler Structure	20,392
Coal Handling Facility	33,665
Turbine Generator Unit	47,707
Electrical Accessories	23,827
Miscellaneous Power Plant Equipment	4,181
Substation and Switchgear Station	195
Substation and Switchgear Station Equipment	<u>4,999</u>
TOTAL DIRECT COST	\$ 491,385
Distributables and Indirects	157,243
Allowance for Indeterminates	<u>64,863</u>
TOTAL	\$ 713,491

*In January 1978 dollars.

TABLE 5-10

COST ESTIMATE FOR
WYOMING COAL-FIRED COGENERATION PLANT
AT GEISMAR, LOUISIANA

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	8,089
Waste Treatment	1,325
Steam and Condensate Distribution System	84,091
Electric Distribution System	2,535
Turbine Building	3,530
Screenwell Structure	952
Water Treatment Plant	1,237
Office and Shops	324
Warehouse and Miscellaneous Structures	256
Boiler Plant Equipment	256,850
Open Boiler Structure	20,392
Coal Handling Facility	33,665
Turbine Generator Unit	47,707
Electrical Accessories	23,827
Miscellaneous Power Plant Equipment	4,181
Substation and Switchgear Station	195
Substation and Switchgear Station Equipment	<u>4,999</u>
TOTAL DIRECT COSTS	\$ 494,155
Distributables and Indirects	158,130
Allowance for Indeterminates	<u>65,229</u>
TOTAL	\$ 717,514

*In January 1978 dollars.

5.2.2 NUCLEAR PLANTS (GEISMAR) - ADVANCED TECHNOLOGY UNDER DEVELOPMENT

5.2.2.1 Consolidated Nuclear Steam System

This order-of-magnitude estimate was prepared assuming an nth-of-a-kind unit using the cost estimate contained in Babcock & Wilcox's report (see Table 5-11).⁽¹⁹⁾ Equipment and systems were deleted to adapt the electric generating plant proposed by B&W to a cogenerating plant (see Table 5-12). Costs were escalated to raise the September 1976 cost level to January 1978. Equipment and systems were added to convert the plant to cogeneration (see Table 5-13).

TABLE 5-11

COST ESTIMATE, PART I (B&W CNSS) CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT AT GEISMAR, LOUISIANA

	Direct Costs* (\$ x 1,000)
Land and Land Rights	380
Special Material	---
Structural and Site Facilities	48,967
Reactor Plant Equipment	64,121
Turbine Plant Equipment	48,300
Electric Plant Equipment	13,220
Miscellaneous Plant Equipment	4,536
Construction Facilities and Equipment	11,533
Engineering Services	31,035
Other Costs	<u>9,285</u>
SUBTOTAL	\$ 231,377
Contingency (10%)	23,138
SUBTOTAL	\$ 254,515
Indirect Costs	<u>53,346</u>
TOTAL	\$ 307,861

*In September 1976 dollars.

TABLE 5-12

COST ESTIMATE, PART II (ESCALATION AND DEDUCTIONS)
 CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT
 AT GEISMAR, LOUISIANA

		Direct Costs* <u>(\$ x 1,000)</u>
Cost Estimate, Part I (Table 5-11)		307,861
<u>Deductions*</u>		
Land and Land Rights	380	
Construction Facilities and Equipment	11,533	
Engineering Services	31,035	
Other Costs	9,285	
Contingency (10%)	23,138	
Indirect Costs	<u>53,346</u>	
TOTAL DEDUCTIONS*		\$ <u>128,717</u>
TOTAL COST*		\$ 179,144
Escalated Cost (9%) **		195,267
<u>Deductions**</u>		
Condenser Equipment	2,500	
Circulating Water System	2,050	
Circulating Water Equipment	450	
400-MW Turbine Generator	25,900	
400-MW Substation	<u>3,150</u>	
TOTAL DEDUCTIONS**		\$ <u>34,050</u>
TOTAL (Modified CNSS - 1 Unit)**		\$ 161,217
TOTAL (Modified CNSS - 2 Units) **		\$ 322,434

*In September 1976 dollars.

**In January 1978 dollars.

TABLE 5-13

COST ESTIMATE, PART III (SUMMARY)
 CONSOLIDATED NUCLEAR STEAM SYSTEM PLANT
 AT GEISMAR, LOUISIANA

	Direct Costs* (\$ x 1,000)
CNSS Modified (Table 5-12)	322,434
Yardwork	3,098
Waste Treatment	---
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Turbine Building	---
Screenwell	---
Water Treatment	---
Offices and Shops	---
Warehouses	188
Reactor Structure	---
Reactor Plant	---
Turbine Generator Unit	9,660
Electrical Accessories	6,752
Miscellaneous Power Plant Equipment	---
Substation Equipment	1,102
Guard House	775
Boiler	40,207
Reboiler	10,545
Superheater	21,259
Fuel Oil System	<u>1,975</u>
TOTAL DIRECT COSTS	\$ 504,621
Indirects	88,700
Distributables	157,700
QA/QC	16,900
Allowance for Indeterminates	<u>76,779</u>
TOTAL	\$ 844,700

*In January 1978 dollars.

5.2.2.2 High Temperature Gas Reactor Steamer

The order-of-magnitude estimate for the high temperature gas reactor was prepared assuming an nth-of-a-kind unit. Costs were developed utilizing existing in-house data and information obtained from General Atomic Company.⁽²¹⁾ The cost estimate is shown on Table 5-14.

TABLE 5-14

COST ESTIMATE FOR
HIGH TEMPERATURE GAS REACTOR
AT GEISMAR, LOUISIANA

	Direct Costs* (\$ x 1,000)
Yardwork	20,100
Control Buildings	33,372
Turbine Building	6,000
Administration Building	1,200
River Water Intake Structures	1,740
Miscellaneous Buildings and Structures	8,400
Auxiliary Buildings	4,530
Reactor Service Buildings	30,075
Reactor Containment Buildings	56,250
Reactor Plant Equipment	315,930
Turbine Generator Unit	41,603
Electrical Accessories	88,200
Miscellaneous Power Plant Equipment	11,106
Substation and Switching Station	4,400
Steam & Condensate Distribution System	84,091
Electrical Distribution	<u>2,535</u>
TOTAL DIRECT COSTS	\$ 709,532
Indirects	87,728
Distributables	198,768
QA/QC	28,602
Allowance for Indeterminates	<u>102,370</u>
TOTAL	\$1,127,000

*In January 1978 dollars.

5.2.3 ADVANCED FOSSIL FUEL TECHNOLOGY COST ESTIMATES FUTURE DEVELOPMENT

5.2.3.1 Eastern Coal Fluidized-Bed Boiler

The order-of-magnitude estimate for the atmospheric fluidized-bed (AFB) steam generating plant was developed utilizing data contained in the report prepared by Stone & Webster for the U.S. Department of Energy under Contract No. EF-77-C-01-2583.⁽²²⁾ It compares the economics of an AFB combustion power plant with a conventional pulverized coal-fired plant. Foster Wheeler Energy Corporation and Babcock & Wilcox, under contract with Stone & Webster, provided the AFB boiler design data and cost information.

Differences in plant design developed in the report were costed and system (block) multipliers calculated and applied to the eastern coal-fired plant at Geismar to arrive at estimated costs. Tables 5-15 and 5-16 provide these cost estimates for AFB plants at Geismar using B&W and FW boilers.

TABLE 5-15

COST ESTIMATE FOR ATMOSPHERIC FLUIDIZED-BED PLANT
USING BABCOCK & WILCOX BOILER AT GEISMAR, LOUISIANA

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	8,089
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Turbine Building	4,363
Screenwell	952
Water Treatment Plant	1,237
Offices and Shops	324
Warehouses and Miscellaneous	256
Boiler Plant Equipment	172,092
Open Boiler Structure	25,205
Coal Handling	42,081
Turbine Generator Unit	44,413
Electrical Accessories	28,259
Miscellaneous Power Plant Equipment	4,181
Substation and Switchyard	<u>5,194</u>
 TOTAL DIRECT COSTS	 \$ 571,788
Distributables and Indirects	165,692
Allowance for Indeterminates	<u>68,348</u>
 TOTAL	 \$ 751,828

*In January 1978 dollars.

TABLE 5-16

COST ESTIMATE FOR ATMOSPHERIC FLUIDIZED-BED PLANT
USING FOSTER WHEELER BOILER AT GEISMAR, LOUISIANA

	Direct Costs* <u>(\$ x 1,000)</u>
Yardwork	8,089
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Turbine Building	2,898
Screenwell	952
Water Treatment Plant	1,237
Offices and Shops	324
Warehouses and Miscellaneous	256
Boiler Plant Equipment	104,679
Open Boiler Structure	16,742
Coal Handling	42,081
Turbine Generator Unit	44,413
Electrical Accessories	27,783
Miscellaneous Power Plant Equipment	4,181
Substation and Switchyard	<u>5,194</u>
 TOTAL DIRECT COSTS	 \$ 431,269
 Distributables and Indirects	 138,006
Allowance for Indeterminates	<u>56,927</u>
 TOTAL	 \$ 626,202

*In January 1978 dollars.

5.2.3.2 Eastern Coal Gasification With Conventional Boiler (Oxygen-Blown and Air-Blown Gasifiers)

Order-of-magnitude estimates for this cogeneration plant arrangement using oxygen-blown and air-blown gasifiers are shown in Tables 5-17 and 5-18. The estimates are comprised of the cost of the coal gasification plant and the cost of the eastern coal-fired cogeneration plant (see Table 5-9) modified to account for larger coal handling facilities, coal gas-fired boilers, larger water treatment facilities, deletion of the precipitators and scrubbers, modifications to the waste treatment facilities, and other related items. See Section 4.4.1.2 for a description of the plant. The costs for the coal gasification process were prorated and escalated from the Electric Power Research Institute Report entitled Economics of Current and Advanced Gasification Processes for Fuel Gas Production.⁽²³⁾

TABLE 5-17

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH
CONVENTIONAL BOILER AND OXYGEN-BLOWN GASIFIER

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	39,400
Oxidant Feed System	100,116
Gasification and Ash Handling	108,561
Gas Cooling	82,068
Acid Gas Removal	50,455
Process Condensate Treating	125,690
Power Recovery	39,895
Utility and Offsite Facilities	114,400
Initial Chemical and Catalyst Charge	2,960
Yardwork	8,500
Waste Treatment	700
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Turbine Building	3,530
Screenwell Structure	952
Water Treatment Plant	1,000
Office and Shops	324
Warehouse and Miscellaneous	256
Boiler Plant Equipment	136,930
Open Boiler Structure	16,855
Turbine Generator Unit	47,707
Electrical Accessories	23,327
Miscellaneous Power Plant Equipment	4,181
Substation & Switchyard Station	195
Substation & Switchyard Equipment	<u>4,999</u>
 TOTAL DIRECT COSTS	 \$ 999,627
 Distributables and Indirects	 319,883
Allowance for Indeterminates	131,950
Royalties (Paid)	<u>21,979</u>
 TOTAL	 \$1,473,439

*In January 1978 dollars.

TABLE 5-18

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH
CONVENTIONAL BOILERS AND AIR-BLOWN GASIFIER

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	39,000
Oxidant Feed System	42,682
Gasification and Ash Handling	107,540
Gas Cooling	50,307
Acid Gas Removal	66,174
Process Condensate Treating	100,202
Power Recovery	45,602
Utility and Offsite Facilities	89,000
Initial Chemical and Catalyst Charge	4,385
Yardwork	8,500
Waste Treatment	700
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Turbine Building	3,530
Screenwell Structure	952
Water Treatment Plant	1,000
Office and Shops	324
Warehouse and Miscellaneous	256
Boiler Plant Equipment	136,930
Open Boiler Structure	16,855
Turbine Generator Unit	47,707
Electrical Accessories	23,327
Miscellaneous Power Plant Equipment	4,181
Substation & Switchyard Station	195
Substation & Switchyard Equipment	<u>4,999</u>
TOTAL DIRECT COSTS	\$ 880,974
Distributables and Indirects	281,926
Allowance for Indeterminates	116,300
Royalties (Paid)	<u>17,886</u>
TOTAL	\$1,297,086

*In January 1978 dollars.

5.2.3.3 Eastern Coal Gasification With Gas Turbines and
Waste Heat Boilers (Unlimited and Limited Power
Generation)

The order-of-magnitude estimates for this cogeneration plant arrangement using unlimited and limited power are shown in Tables 5-19 and 5-20. The estimates were developed from data contained in the Electric Power Research Institute report entitled Comparative Evaluation of High and Low Temperature Gas Cleaning for Coal Gasification - Combined Cycle Power Systems.⁽²⁴⁾ This report was prepared by Stone & Webster for EPRI, under Research Project 243-2, to evaluate the incentives for developing hot-gas purification technology for application to coal gasification combine-cycle power generating systems.

The cost information from this report was prorated on the basis of coal gas output to develop the cost of the coal gasification plant. The balance of plant cost was developed by obtaining current market prices for major equipment and systems and utilizing existing in-house cost data.

TABLE 5-19

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH GAS TURBINES AND WASTE
HEAT BOILERS - UNLIMITED POWER GENERATION

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	60,000
Gasification	185,539
Gas Cooling/Heating	96,177
Air Compression	79,532
Water Treatment	211,806
Cold Purification	132,832
Combined Cycle	499,887
Offsites	273,278
Tar-Fired Power Unit	306,894
Initial Charge for Catalyst and Chemicals	10,690
Yardwork	3,235
Waste Treatment Plant	800
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Screenwell Structure	1,200
Water Treatment (Feedwater & Condensate)	1,500
Office and Shops	150
Warehouse and Miscellaneous Structures	100
Boiler Plant Equipment	34,220
Electrical Accessories	8,050
Miscellaneous Power Plant Equipment	1,000
Substation and Switchyard Station	700
Substation and Switchyard Station Equipment	<u>17,020</u>
 TOTAL DIRECT COSTS	 \$2,011,236
Distributables and Indirects	645,317
Allowance for Indeterminates	<u>266,000</u>
 SUBTOTAL PROJECT COST	 \$2,922,553
Royalties (Paid)	<u>53,447</u>
 TOTAL	 \$2,976,000

*In January 1978 dollars.

TABLE 5-20

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH GAS TURBINES AND WASTE
HEAT BOILERS - LIMITED POWER GENERATION

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	37,700
Gasification	89,834
Gas Cooling/Heating	46,566
Air Compression	38,508
Water Treatment	102,552
Cold Purification	64,315
Combined Cycle	180,339
Offsites	132,316
Tar-Fired Power Unit	148,592
Initial Charge for Catalyst and Chemicals	5,398
Yardwork	2,750
Waste Treatment Plant	680
Steam and Condensate Distribution System	84,091
Electrical Distribution System	2,535
Screenwell Structure	1,020
Water Treatment (Feedwater and Condensate)	1,275
Office and Shops	125
Warehouse and Miscellaneous Structures	85
Boiler Plant Equipment	24,000
Electrical Accessories	6,000
Miscellaneous Power Plant Equipment	850
Substation and Switchyard Station	226
Substation and Switchyard Station Equipment	<u>5,640</u>
TOTAL DIRECT COSTS	\$1,082,500
Distributables and Indirects	346,511
Allowance for Indeterminates	<u>144,000</u>
SUBTOTAL PROJECT COST	\$1,573,011
Royalties (Paid)	<u>26,989</u>
TOTAL	\$1,600,000

*In January 1978 dollars.

5.2.3.4 Eastern Coal Gasification With Fuel Cell (Unlimited and Limited Power Generation)

This scheme assumes that clean coal gas can be used directly in a molten carbonate fuel cell. The gasification system portion is a Lurgi air-blown system. Tables 5-21 and 5-22 show the estimates for unlimited and limited power generation.

The fuel cell costs were assumed to be \$350/kW, based on an upper range for predicted cost given in a report prepared for ERDA by United Technologies.⁽²⁵⁾

TABLE 5-21

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH
FUEL CELLS - UNLIMITED POWER GENERATION

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	69,300
Oxidant Feed System	82,980
Gasification and Ash Handling	208,010
Gas Cooling	97,800
Acid Gas Removal	128,650
Process Condensate Treating	187,040
Power Recovery	88,650
Utilities and Offsites	205,945
Fuel Cells	897,934
Initial Chemical and Catalyst Charge	11,125
Steam and Condensate Distribution System	84,091
Electrical Distribution System	<u>2,535</u>
 TOTAL DIRECT COSTS	 \$2,064,060
 Distributables and Indirects	 660,500
Allowance for Indeterminates	<u>27,250</u>
 SUBTOTAL PROJECT COST	 \$2,751,810
 Royalties (Paid)	 <u>45,420</u>
 TOTAL	 \$2,797,230

*In January 1978 dollars.

TABLE 5-22

COST ESTIMATE FOR
EASTERN COAL GASIFICATION WITH
FUEL CELLS - LIMITED POWER GENERATION

	Direct Costs* <u>(\$ x 1,000)</u>
Coal Handling Facilities	41,230
Oxidant Feed System	41,120
Gasification and Ash Handling System	103,600
Gas Cooling	48,460
Acid Gas Removal	63,750
Process Condensate Treating	82,930
Power Recovery	43,930
Utilities and Offsites	100,100
Fuel Cells	88,040
Fuel Fired Boiler System	98,590
Initial Chemical and Catalyst Charge	3,577
Steam and Condensate Distribution System	84,091
Electrical Distribution System	<u>2,535</u>
TOTAL DIRECT COSTS	\$ 801,953
Distributables and Indirects	256,647
Allowance for Indeterminates	<u>105,900</u>
SUBTOTAL PROJECT COST	\$1,164,500
Royalties (Paid)	<u>14,600</u>
TOTAL	\$1,179,100

*In January 1978 dollars.

U.S. DEPARTMENT OF AGRICULTURE
WASHINGTON, D.C. 20250

SECTION 6

ECONOMIC ANALYSIS

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SECTION 6

ECONOMIC ANALYSIS

This section presents the basic assumptions and data necessary to make an economic comparison of plant cogeneration alternatives. The basic assumptions and economic data are included in Section 6.1. Analyses of these data are discussed in Section 6.2, Economic Comparisons.

Other factors impacting the design and economics of the cogeneration plant are developed in Section 6.3, which discusses the reliability of steam generating equipment; Section 6.4, which describes the economics of condensing capabilities using a consolidated nuclear steam system (CNSS) and a high temperature gas-cooled reactor (HTGR) steamer; and Section 6.5, which investigates sequential installation.

6.1 ECONOMIC ASSUMPTIONS AND TABULATIONS

This section contains the basic assumptions and economic tabulations developed to permit economic comparison of the various cogeneration plant concepts at each site. The basic assumptions and economic factors are listed in Table 6-1. Sample calculations depicting the method used to determine the total capital costs and annual operating costs for Tables 6-4 and 6-5 are shown in Tables 6-2 and 6-3, respectively.

Tables 6-4 and 6-5, for Orange and Geismar, respectively, summarize the operating conditions, capital costs, operating costs, and process steam costs for both current technology and advanced technology presently being developed. Because of the potential utilization of inherent excess steam generating capacity in the CNSS plant, data are included for plants with and without condensing capabilities. For comparison purposes, process steam costs are also shown for the users' facilities assuming that they would continue operating using No. 2 fuel oil. These costs include only fuel and operating and maintenance costs with no allowance for capital costs, which are unknown but assuredly would be necessary.

The cost data for Tables 6-4 and 6-5 were calculated using assumptions from Table 6-1 and the capital cost estimates in Section 5.

Since the different alternatives have unequal economic lives, comparison has been made on the basis of uniform annual costs to the users. These are based on the minimum revenue requirements of the cogeneration entity necessary to

realize a rate of return of 10 percent, which is a return that is appropriate for a utility. The higher rates typically required by unregulated industries would increase users' steam costs.

The fixed charges are the components of the revenue requirements, which are a function of the invested capital. These include return, depreciation, income tax, other taxes, and insurance. The fixed charge rate is the sum of all these components expressed as a percentage of the investment capital. The higher fixed charge rate for the nuclear alternatives results from a higher percentage for income tax calculated for a longer construction period and operating life.

The levelized fuel and operating and maintenance charges are the uniform annual costs which have the same present value in the first year of operation as the predicted costs. The total of these operating costs and the fixed charges represents revenue which must be realized from the users. However, for this they receive electric power which is shown as a credit based on the levelized utility rate. The net annual operating cost represents the users' levelized before-income-tax cash flow chargeable to process steam. The net-of-taxes cash flow would be reduced by the users' effective income tax rate.

The bottom line shows the average levelized cost per thousand pounds of process steam assuming that the cogeneration plant is able to supply steam equivalent to full load capacity for 7884 hours per year. This equates to a load factor of 90 percent which is based on users' requirements, not plant availability. (Plant reliability is treated separately in Section 6.3.) Cogeneration plant outages would increase the unit steam cost and entail backup expenses as shown in Figure 7-1. No attempt has been made to develop the sale price of steam at the various pressures which would be affected by heat input, electric power generated, and the quantity and condition of returned condensate.

The advanced technology costs which were investigated only for Geismar are shown in Table 6-6.

Table 6-7 provides various unit cost economic data for reference and general information. It must be emphasized that these data are site specific and therefore are correct only for Geismar and Orange and their projected steam requirements.

TABLE 6-1

ASSUMPTIONS USED IN ECONOMIC ANALYSES

	<u>Fuel Oil</u>		<u>Coal</u>				<u>Coal</u>			
	No. 6	No. 2	Eastern	Western	CNSS	HTGR	Gasifi- cation	AFB	Fuel Cells	Comb. Cycle
1. Construction period (yrs)	5	-	6	6	7	7	6	6	6	6
2. Operating date	1984	-	1985	1985	1986	1986	1985	1985	1985	1985
3. Basis for capital costs	1/78	-	1/78	1/78	1/78	1/78	1/78	1/78	1/78	1/78
4. Escalation of capital costs (% per year) (1)	7	-	7	7	7(6)	7	7	7	7	7
5. Interest during con- struction (% per year) (2)	9	9	9	9	9	9	9	9	9	9
6. Operating life of unit (yrs)	30	-	30(5)	30(5)	35(7)	35	30	30	30	30
7. Rate of return (%)	10	-	10(5)	10(5)	10(5)	10	10	10	10	10
8. Annual fixed charge rate (%) (16)	15	-	15(5)	15(5)	16	16	15	15	15	15
9. Load factor (%)	90	90	90	90	90	90	90	90	90	90
10. Fuel cost (1977 \$ per 10 ⁶ Btu)	1.98(3)	2.55(3)	1.11	1.22(4)	0.72(8)	0.63	1.11	1.11(12)	1.11	1.11
11. Escalation of fuel cost (% per year)	7(4)	7	6	6	(10)	(10)	6	6	6	6
12. Limestone cost (1977 \$ per ton)	13	-	13	13	-	-	-	13	-	-

TABLE 6-1 (Cont)

	<u>Fuel Oil</u>		<u>Coal</u>				<u>Coal</u> <u>Gasifi-</u> <u>cation</u>		<u>Fuel</u> <u>Cells</u>	<u>Comb.</u> <u>Cycle</u>
	No. 6	No. 2	Eastern	Western	CNSS	HTGR		AFB		
13. Escalation of lime- stone (% per year)	6	-	6	6	-	-	-	6	-	-
14. O&M costs (1977 \$/10 ⁶ Btu)	0.23	0.14	0.29	0.27	0.18	0.16	(13)	0.26	(14)	(15)
15. Escalation for O&M costs (% per year)	6	6	6(9)	6(9)	6(9)	6	6	6	6	6
16. GSU electric power rates (1977 mills/kWh)	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
17. Escalation for electric power (% per year):										
To 1985	11	11	11	11	11	11	11	11	11	11
Beyond 1985	7	7	7	7	7	7	7	7	7	7
18. Sulfur (\$ per ton)	-	-	-	-	-	-	20	-	20	20
19. Escalation for sulfur (% per year)	-	-	-	-	-	-	6	-	6	6
20. Aqueous ammonia (\$ per ton)	-	-	-	-	-	-	24	-	24	24
21. Escalation for aqueous ammonia, (% per year)	-	-	-	-	-	-	6	-	6	6
22. Anhydrous ammonia (\$ per ton)	-	-	-	-	-	-	120	-	120	120
23. Escalation for anhydrous ammonia (% per year)	-	-	-	-	-	-	6	-	6	6

TABLE 6-1 (Cont)

NOTES

Unless noted otherwise, economic factors are best estimates by Stone & Webster Engineering Corporation.

- (1) Escalation compounded through 60% of the construction period.
- (2) Simple interest (not compounded) during last 40% of construction period.
- (3) From Reference (c) for No. 6 and No. 2 fuel oil.
- (4) From Reference (c).
- (5) From Reference (a) Section 5.9.
- (6) From Reference (b) page 4-18.
- (7) From Reference (b) page 4-15, assuming same life of CNSG and CNSS.
- (8) From Reference (d) page B-4 excluding plutonium credit and escalated one year.
- (9) From Reference (e) page 28.
- (10) Yellowcake escalation (1/3) is estimated at 6% per year. Conversion, enrichment, shipping, and fabrication escalation (2/3) is estimated at 4% per year.
- (11) Scrubbers included for fossil units except for No. 2 oil.
- (12) Comparison made on basis of eastern coal.
- (13) 0.52 for air-blown OEM, 0.54 for oxygen-blown.
- (14) 0.61 for unlimited power, 0.54 for limited power.
- (15) 0.63 for unlimited power, 0.57 for limited power.
- (16) Includes taxes, insurance, and debt service.

REFERENCES

- (a) Steam Supply Study in Geismar Area for Gulf States Utilities, prepared by Stone & Webster Engineering Corporation, Cherry Hill, N.J. (July 1975).
- (b) Nuclear Power Plant Siting Study, prepared for Department of the Army by United Engineers and Constructors, Inc. (June 1976).
- (c) R. G. Chapman, Gulf States Utilities Company, to R. B. Steiner, Stone & Webster Engineering Corporation, communication dated July 22, 1977.
- (d) 400-MWe Consolidated Nuclear Steam System (CNSS) - 1200 MWe/Conceptual Design, prepared by Babcock & Wilcox Company for Oak Ridge National Laboratory, ORNL/Sub-4390/4 (June 1977).
- (e) Evaluation of Geismar Steam - Electric Project, prepared for Gulf States Utilities Company by Arthur D. Little, Inc. (December 12, 1975).

TABLE 6-2
SAMPLE CALCULATIONS FOR ECONOMIC COMPARISON
CAPITAL COSTS

	Capital Costs <u>(\$ x 1,000)</u>
Example is for Geismar coal-fired plant using eastern coal:	
6-Year Construction Period 1985 Service Date	
Estimated capital cost (in January 1978 dollars) .	713,491
Escalation based on 7% per year compounded through 60% of construction period.	
$(1.07)^{1+(0.6 \times 6)} - 1 = 0.3651 \times \text{capital cost}$	<u>260,496</u>
SUBTOTAL (Escalated Capital Cost)	\$ 973,987
Interest during construction at 9% per year simple interest during last 40% of construction period.	
$(0.09) \times (6 \text{ yrs} \times 0.4) = 0.216 \times \text{escalated capital cost}$	<u>210,381</u>
TOTAL CAPITAL COSTS	\$1,184,368

Annual
Operating Costs
(\$ x 1,000)

Example is for Geismar coal-fired plant using eastern coal:

Assumptions

30-Year Operating Life
Rate of Return - 10%
Boiler Efficiency - 86%
Availability - 90%

1. Fixed charges at 15% of total capital cost for insurance, taxes, and debt service. \$177,655

2. Fuel costs (\$1.11/(10)⁶ Btu) escalated at 6% and levelized.

$$\frac{\$1.11 \times 1.59385 \times 16.771225}{9.426914} = \$3.15/(10)^6 \text{ Btu}$$

$$\frac{2630.958 \text{ Mwt} \times 3413 (10)^3 \times 3.15 \times 7,884 \text{ hr/yr}}{0.86 \times (10)^6} \quad \text{span style="float: right;">\$259,304}$$

3. O&M costs (\$0.29/(10)⁶ Btu) escalated at 6% and levelized.

$$\frac{\$0.29 \times 1.59385 \times 16.771225}{9.426914} = \$0.82/(10)^6 \text{ Btu}$$

$$\frac{2630.958 \text{ Mwt} \times 3413 (10)^3 \times 0.82 \times 7,884 \text{ hr/yr}}{0.86 \times (10)^6} \quad \text{span style="float: right;">\$ 67,501}$$

SUBTOTAL (Annual Operating Cost) \$504,460

4. Credit for power (16.5 mills/kWh) escalated at 11% to 1985 and 7% thereafter and levelized.

$$\frac{16.5 \times 2.30454 \times 18.79176}{9.426914} = 75.7 \text{ mills/kWh}$$

$$352.2 \text{ MWe} \times 7,884 \text{ hrs} \times 0.0757 (10)^3 \quad \text{span style="float: right;">\$210,200}$$

NET ANNUAL OPERATING COST \$294,260

5. Steam cost/1000 lb process steam

$$\frac{\$294,260 (10)^3}{5,840 \text{ lb} \times (10)^3/\text{hr} \times 7,884 \text{ hr/yr}} \quad \text{span style="float: right;">\$ 6.39}$$

TABLE 6-3

SAMPLE CALCULATIONS FOR ECONOMIC COMPARISON
OPERATING COSTS

	Annual Operating Costs <u>(\$ x 1,000)</u>
Example is for Geismar coal-fired plant using eastern coal:	
<u>Assumptions</u>	
30-Year Operating Life	
Rate of Return - 10%	
Boiler Efficiency - 86%	
Availability - 90%	
1. Fixed charges at 15% of total capital cost for insurance, taxes, and debt service.	\$177,655
2. Fuel costs (\$1.11/(10) ⁶ Btu) escalated at 6% and levelized. $\frac{\$1.11 \times 1.59385 \times 16.771225}{9.426914} = \$3.15/(10)^6 \text{ Btu}$ $\frac{2630.958 \text{ MWt} \times 3413 (10)^3}{0.86 \times (10)^6} \times 3.15 \times 7,884 \text{ hr/yr}$	\$259,304
3. O&M costs (\$0.29/(10) ⁶ Btu) escalated at 6% and levelized. $\frac{\$0.29 \times 1.59385 \times 16.771225}{9.426914} = \$0.82/(10)^6 \text{ Btu}$ $\frac{2630.958 \text{ MWt} \times 3413 (10)^3}{0.86 \times (10)^6} \times 0.82 \times 7,884 \text{ hr/yr}$	\$ 67,501
SUBTOTAL (Annual Operating Cost)	\$504,460
4. Credit for power (16.5 mills/kWh) escalated at 11% to 1985 and 7% thereafter and levelized. $\frac{16.5 \times 2.30454 \times 18.79176}{9.426914} = 75.7 \text{ mills/kWh}$ $352.2 \text{ MWe} \times 7,884 \text{ hrs} \times 0.0757 (10)^3$	\$210,200
NET ANNUAL OPERATING COST	\$294,260
5. Steam cost/1000 lb process steam $\frac{\$294,260 (10)^3}{5,840 (10)^3 \text{ lb/hr} \times 7,884 \text{ hr/yr}}$	\$ 6.39

TABLE 6-4
ECONOMIC COMPARISON - ORANGE SITE

Existing No. 2 Oil-Fired Plants Compared With Plants That Are:				Proposed Plants					
				Fossil-Fired			Nuclear		
				Alabama Coal	Wyoming Coal	No. 6 Fuel Oil	HTGR (1-1200 MWt)	CNSS* (1-1200 MWt) without condensing	CNSS* (1-1200 MWt) with condensing
Coal	Oil	Nuclear							
Initial Steam Press (psia)				2,415	2,415	2,415	2,415	640	640
Initial Steam Temp. (F)				1,000	1,000	1,000	1,000	700	700
Steam Flow (lb/hr)				3,441,382	3,441,382	3,441,382	3,239,239	2,695,872	4,298,788
Service Date				1985	1985	1984	1986	1986	1986
Gross Generation (MWe)				185.3	185.3	185.3	188.2	42.86	183.06
Aux. Power & FW Pump (MWe)				36.7	36.7	30.1	23.6	19.06	30.76
Net Generation (MWe)				148.6	148.6	155.2	164.6	23.6	152.3
Heat Input (MWt)				989.360	989.360	989.360	1007.363	871.083	1315.560
Heat Output (MWt)				816.162	816.162	816.162	815.775	830.114	1136.545
<u>Capital Cost (\$ x 1,000)</u>									
(1/78) Cost				292,620	294,993	247,286	410,000	380,800	424,200
Escalation				106,836	107,702	76,659	172,897	160,583	178,885
Total				399,456	402,695	323,945	582,897	541,383	603,085
Int. During Construction				86,282	86,982	58,310	146,890	136,429	151,977
Total				485,738	489,677	382,255	729,787	677,812	755,062
<u>Annual Cost (\$ x 1,000)</u>									
Fixed Charges				72,861	73,452	57,338	116,766	108,450	120,810
Fuel Charges				247,989	231,797	196,258	42,286	64,389	85,678
O&M Charges				11,306	10,652	19,192	13,824	14,227	21,044
Total				195,755	204,394	272,788	172,876	187,066	227,532
Credit for Power				(88,687)	(88,687)	(86,508)	(113,160)	(16,362)	(104,704)
Net Annual Operating Cost				107,068	115,707	186,280	59,716	170,704	122,828
Process Steam Cost (\$/1,000 lb - 7,884 hr/yr @ 2,195,000 lb/hr)				14.98**	14.01**	10.76	3.45	9.86	7.10

*Plus oil-fired superheater.

**Process steam cost based on operating costs only.
No allowance for capital cost (fixed charges).

TABLE 6-5

ECONOMIC COMPARISON - GEISMAR SITE

Existing No. 2 Oil-Fired Plants Compared With Plants That Are:				Proposed Plants					
				Fossil-Fired			Nuclear		
				Alabama Coal	Wyoming Coal	No. 6 Fuel Oil	HTGR (3-1200 MWt)	CNSS* (2-1200 MWt) without condensing	CNSS* (2-1200 MWt) with condensing
Coal	Oil	Nuclear							
Initial Steam Press (psia)				2,415	2,415	2,415	2,415	690	690
Initial Steam Temp. (F)				1,000	1,000	1,000	1,000	750	750
Steam Flow (lb/hr)				9,237,178	9,237,178	9,237,178	8,633,414	6,784,539	8,591,312
Service Date	1985	1984	1986	1985	1985	1984	1986	1986	1986
Gross Generation (MWe)				448.8	448.8	448.8	462.1	90.8	248.8
Aux. Power & FW Pump (MWe)				96.6	96.6	79.1	62.1	52.4	65.6
Net Generation (MWe)				352.2	352.2	369.7	400	38.4	183.2
Heat Input (MWt)				2630.958	2630.958	2630.958	2684.883	2371.290	2872.295
Heat Output (MWt)				2214.604	2214.604	2214.604	2213.709	2286.277	2631.678
<u>Capital Cost (\$ x 1,000)</u>									
(1/78) Cost				713,491	717,514	636,172	1,127,000	844,700	888,900
Escalation				260,496	261,964	197,213	475,256	356,210	374,849
Total				973,987	979,478	833,385	1,602,256	1,200,910	1,263,749
Int. During Construction				210,381	211,567	150,009	403,769	302,629	318,465
Total				1,184,368	1,191,045	983,394	2,006,025	1,503,539	1,582,214
<u>Annual Cost (\$ x 1,000)</u>									
Fixed Charges				177,655	178,657	147,509	320,964	240,566	253,154
Fuel Charges	685,749	640,975	789,436	259,304	284,823	521,900	112,702	206,219	230,215
O&M Charges	31,263	29,456	34,955	67,501	63,385	51,038	36,845	39,914	47,598
Total				504,460	526,865	720,447	470,511	486,699	530,967
Credit for Power				(210,200)	(210,200)	(206,070)	(274,994)	(26,399)	(125,947)
Net Annual Operating Cost				294,260	316,665	514,377	195,517	460,300	405,020
Process Steam Cost (\$/1,000 lb - 7,884 hr/yr @ 5,840,000 lb/hr)	15.57**	14.56**	17.90**	6.39	6.88	11.17	4.25	10.00	8.80

*Plus oil-fired boiler and superheater.

**Process steam cost based on operating costs only.

Nothing included for capital costs (fixed charges).

TABLE 6-6

ECONOMIC COMPARISON - ADVANCED TECHNOLOGY (FUTURE DEVELOPMENT) - GEISMAR SITE

	Atmospheric Fluidized-Bed		Coal Gasification					
	Foster-Wheeler	Babcock & Wilcox	With Conventional Boiler		Air-Blown Gasification With			
			Air-Blown	Oxygen-Blown	Combined Cycle		Fuel Cell	
					Unlimited Power	Limited Power	Unlimited Power	Limited Power
Initial Steam Pressure (psia)	2,415	2,415	2,415	2,415	970/690/290	970/690/290	970/690/290	970/690/290
Initial Steam Temp. (F)	1,000	1,000	1,000	1,000	850/684/509	850/684/509	850/684/509	850/684/509
Steam Flow (lb/hr)	9,237,178	9,237,178	9,237,178	9,237,178	8,316,158			
Service Date	1985	1985	1985	1985	1985	1985	1985	1985
Gross Generation (MWe)	448.832	448.832	-	-	2206.7	552	-	-
Aux. Power (MWe)	104.532	108.932	-	-	352.7	200	-	-
Net Generation (MWe)	344.3	339.9	474.7(1)	476.7(1)	1854	352	2701.3	352
Heat Input (MWt)	2630.958	2630.958	4791.713	4867.592	8161.096	4629.752	10989.0	4487.3
Heat Output (MWt)	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604	2214.604
Capital Cost (\$ x 1,000)								
1/78 Cost	626,202	751,828	1,297,086	1,473,439	2,976,000	1,600,000	2,797,230	1,179,100
Escalation	228,626	274,492	473,566	537,953	1,086,538	584,160	1,021,269	430,489
Total	854,828	1,026,320	1,770,652	2,011,392	4,062,538	2,184,160	3,818,499	1,609,589
Int. During Const.	184,643	221,685	382,461	434,461	877,508	471,779	824,796	347,671
Total	1,039,471	1,248,005	2,153,113	2,445,853	4,940,046	2,655,939	4,643,295	1,957,260
Annual Costs (\$ x 1,000)								
Fixed Charges	155,921	187,201	322,967	366,878	741,007	398,391	696,494	293,589
Fuel Charges	258,163	259,787	406,148	412,579	691,739	392,420	931,431	380,346
O&M Charges	60,402	60,782	189,536	200,396	397,475	208,045	511,548	184,739
Total	474,486	507,770	918,651	979,853	1,830,221	998,856	2,139,473	858,674
Credit								
Power	(205,485)	(202,859)	(283,310)	(284,504)	(1,106,502)	(210,080)	(1,612,187)	(210,080)
Sulfur	-	-	(8,942)	(9,072)	(15,354)	(8,711)	(20,507)	(8,374)
Ammonia	-	-	(22,003)	(22,450)	(37,810)	(21,450)	(50,460)	(20,605)
Net Operating Cost	269,001	304,911	604,396	663,827	670,555	758,615	456,319	619,615
Process Steam Cost (\$/1,000 lb - 7,884 hr/yr @ 5,840,000 lb/hr)	5.84	6.62	13.13	14.42	14.56	16.48	9.91	13.46

(1) Sum of fossil plant and gasification plant outputs.

TABLE 6-7

UNIT COST DATA

	Net kWh per 1,000 Lb Process Steam	Net Operating Cost \$/1,000 lb Process Steam		Capital Cost Per 1,000 lb/hr Process Steam		Capital Cost/kW	
		Before Credit for Power	After Credit for Power	January 1978 Dollars	Including Escalation and I.D.C.	January 1978 Dollars	Including Escalation and I.D.C.
<u>Geismar</u>							
Eastern Coal	60.3	10.96	6.39	122,173	202,803	2,026	3,363
Western Coal	60.3	11.44	6.88	122,862	203,946	2,037	3,382
No. 6 Fuel Oil	63.3	15.65	11.17	108,934	168,389	1,721	2,660
HTGR	68.5	10.21	4.25	192,979	343,497	2,818	5,015
CNSS	6.6	10.57	10.00	144,640	257,455	21,997	39,155
AFB							
Foster-Wheeler	59.0	10.31	5.84	107,226	177,992	1,819	3,019
Babcock & Wilcox	58.2	11.03	6.62	128,738	213,699	2,212	3,672
Coal Gasification							
Air-Blown w/Boilers	81.3	19.95	13.13	222,104	368,684	2,732	4,536
Oxygen-Blown w/Boilers	81.6	21.28	14.42	252,301	418,810	3,091	5,131
w/Comb. Cycle-Unlimited Power	317.5	39.75	14.56	509,589	845,898	1,605	2,665
w/Comb. Cycle-Limited Power	60.3	21.69	16.48	273,973	454,784	4,545	7,545
w/Fuel Cell-Unlimited Power	462.6	46.47	9.91	478,978	795,085	1,036	1,719
w/Fuel Cell-Limited Power	60.3	18.65	13.46	201,901	335,147	3,350	5,560
<u>Orange</u>							
Eastern Coal	67.7	11.31	6.19	133,312	221,293	1,969	3,269
Western Coal	67.7	11.81	6.69	134,393	223,087	1,985	3,295
No. 6 Fuel Oil	70.7	15.76	10.76	112,659	174,148	1,593	2,463
HTGR	75.0	9.99	3.45	186,788	332,477	2,491	4,434
CNSS (Without Condensing)	10.8	10.81	9.86	173,485	308,798	16,000	28,479

6.2 ECONOMIC COMPARISONS

The objective is to compare cost data for the various alternatives for each site and arrive at the most economical plant arrangement based on net steam costs. It should be emphasized that the following are economic comparisons for nth-of-a-kind plants providing the required process steam. The nuclear plants use standard designs, which result in a mismatch of steam generating capacity and higher capital costs. Condensing capability utilizing inherent excess steam generating capacity to generate additional electric power is not included in the basic plant arrangement used in the comparisons, but it is treated separately.

Pairs of plants were compared in a logical sequence. For example, the two coal-fired plants were first compared to establish which was best economically; the choice was then compared to the reference oil-fired plant. This method was used for both current and advanced technologies and then between those technologies. Figure 6-1 shows the step-by-step procedure, the combinations compared, and the resulting conclusions. Similar cost data allowed conclusions applicable at both sites.

Final plant selection, considering all major factors, is developed in Section 7 of this report.

6.2.1 COAL-FIRED PLANTS (EASTERN COAL VS WESTERN COAL) AT ORANGE AND GEISMAR

Review and comparison of the economic evaluation data (Tables 6-4 and 6-5) for the eastern and western coal-fired plants at Orange and Geismar indicate that the high-sulfur eastern (Alabama) coal is the better choice of fuel for the coal-fired cogeneration plant.

The cost estimates and economic evaluations show that the capital costs for western coal-fired plants are only slightly higher than eastern coal, principally because of the higher cost of the boilers, their accessories, and the precipitators. Net annual operating costs favor eastern coal by 7.6 percent at Geismar and 8 percent at Orange. This amounts to an annual savings of \$22,405,000 and \$8,639,000, respectively. On the basis of dollars per thousand pounds of process steam, eastern coal is approximately \$0.49 less than western coal (\$6.88 and \$6.39 at Geismar, \$6.69 and \$6.19 at Orange).

Although the delivered price of western coal for the regions considered is less than for eastern coal, the higher Btu value of eastern coal results in a 9 percent fuel savings. This savings exceeds the 6.5 percent higher operating and maintenance cost created by the high sulfur content of the

coal. For eastern coal to have the same operating cost as western coal, fuel cost per million Btu would have to increase from \$1.11 to \$1.207, or about 8.64 percent. Limestone cost would have to more than double to equalize net operating costs.

6.2.2 EASTERN COAL-FIRED VS OIL-FIRED PLANTS AT ORANGE AND GEISMAR

The total capital cost is about 17 percent less for an oil-fired plant; however, as shown below, the coal-fired plant burning eastern coal is the better choice economically.

The annual costs for fixed charges and operating and maintenance are 19 percent less at Geismar and 22 percent less at Orange for the oil-fired steam generating plant; i.e., \$46,609,000 and \$21,715,000, respectively. However, the levelized cost difference for the two fuels is \$3.19 per million Btu, making the coal-fired plant fuel favorable by \$262,596,000 per year at Geismar. Fuel savings at Orange amount to \$98,748,000 per year.

When a credit for electric power generation is included, the cost per thousand pounds of process steam is \$6.31 for the coal-fired plant compared to \$11.17 for the oil-fired plant at Geismar. The costs at Orange are \$6.19 for coal and \$10.76 for oil. Eastern coal is about 43 percent less per thousand pounds of process steam at both sites.

Historically, maintenance outages for coal-fired plants have been higher than for oil-fired plants. The above analysis, which is based on 7,884 hours per year for both plants, tends to favor the coal-fired plant. However, this factor does not greatly impact the overall results. Assuming that users' facilities are operated during a boiler outage, the difference in fuel cost and credit for power reduces the difference in net operating cost. To equal the cost differences shown on Tables 6-4 and 6-5, one coal-fired boiler would have to be out of service at least 6,500 hours per year more than the oil-fired unit. Based on reliability data, downtime of this magnitude is not expected.

6.2.3 CONSOLIDATED NUCLEAR STEAM SYSTEM VS HIGH TEMPERATURE GAS-COOLED REACTOR AT ORANGE AND GEISMAR

The HTGR emerges, by far, as the better economic choice for a nuclear-powered cogeneration plant when compared with the CNSS for the conditions encountered at Orange and Geismar.

Capital cost of the HTGR is approximately 8 percent higher than the CNSS at Orange. At Geismar, the HTGR is approximately 33 percent higher due to the fact that three

1200-MW units must be used to provide the 2631-MW heat input required. This results in excess steam generating capacity. A third CNSS unit is not required because steam users' projected needs can be met with two CNSS units, a superheater, and an oil-fired steam generator.

The annual operating costs for the CNSS are slightly higher than the HTGR (3.4 percent at Geismar and 8 percent at Orange) before credit is taken for power generated and exported. The net power generation after deducting requirements for auxiliaries at Geismar is 400 MW for the HTGR versus only 38.4 MW for the CNSS. At Orange, net generated power is 164.6 MW for the HTGR versus 23.8 MW for the CNSS. The annual value of these differences is \$248,595,000 and \$96,798,000, respectively, making the net annual operating cost less for the HTGR by 57 percent at Geismar and 65 percent at Orange. In terms of dollars per thousand pounds of process steam, steam cost using the HTGR at Geismar is \$4.25 compared to \$10.00 for the CNSS. At Orange, steam costs are \$3.45 versus \$9.86.

6.2.4 EASTERN COAL AND HIGH TEMPERATURE GAS-COOLED REACTOR AT ORANGE AND GEISMAR

Economically, the HTGR is the better choice of steam generator when compared to an eastern coal-fired boiler. This results from a fuel cost which is only one-half that of an eastern coal-fired boiler on an escalated and levelized basis. Also, the net available electrical output for export is 12 percent higher because of lower auxiliary power requirements for the HTGR plant. The maintenance costs for the HTGR are also estimated to be considerably less. These factors result in a net cost of \$4.25 per thousand pounds of process steam for the HTGR plant, which represents approximately 67 percent of the cost for the eastern coal-fired plant at Geismar. At Orange, the estimated net cost of \$3.45 per thousand pounds of process steam represents approximately 56 percent of the eastern coal-fired plant steam cost. At the projected 1985 steam demand level, this amounts to annual savings of \$98,743,000 and \$47,352,000 for Geismar and Orange, respectively.

Initial total capital costs are considerably higher for the HTGR: 69 percent at Geismar and 50 percent at Orange. The Geismar plant is somewhat more because the HTGR units are not operating at 100 percent capacity. Two HTGR units are insufficient to meet the users' demands and a third unit would have to be added, creating excess capacity. The excess steam generating capacity could be available initially to generate additional power or to provide process steam for future needs.

Methods of utilizing the excess capacity are dependent on ownership of the cogeneration plant and the owners' specific needs. The basic arrangement and cost estimate does not consider methods of utilizing the excess steam generating capacity, since the original concept of the study is to provide a cogeneration plant capable of meeting the users' projected steam requirements, not to meet users' electric power needs.

Section 6.2.10 discusses the merits of utilizing the excess steam capacity in a condensing steam turbine.

6.2.5 COAL GASIFICATION ALTERNATIVES GENERATING LIMITED POWER

This section considers oxygen- and air-blown gasifiers with conventional boilers, gas turbines, and fuel cells used in a limited power generation mode. A cogeneration plant that uses air-blown coal gasification in combination with conventional coal gas-fired boilers produces the lowest net operating cost when compared to arrangements using either fuel cells or the gas turbine combined cycle.

To allow comparison on an equivalent basis, three coal gasification arrangements were developed to produce the required process steam while limiting the net electrical output to 352 MW. This output corresponds to the power developed by fossil fuel fired cogeneration plants.

In the first alternative studied, the coal gasification plant provides coal gas to conventional boilers in a cogeneration plant. Both air-blown and oxygen-blown gasification plants were considered. The results indicate the air-blown gasifier to be the more economical choice. This particular arrangement provides more than 352 MW of electric power due to the electrical generation which is available from the gasification plant.

Although either air-blown or oxygen-blown Lurgi gasifiers are suitable to produce coal gas, the arrangements utilizing gasification with the gas turbine combine cycle and the fuel cell are based on air-blown gasifiers, which provide higher thermal efficiency.

The air-blown gasifier has lower net operating costs than the oxygen-blown system when combined with conventional boilers. Net costs are \$59,431,000 less per year, with the cost per thousand pounds of process steam being \$13.13 compared to \$14.42, or approximately 9 percent less than the oxygen-blown arrangement. This combination also results in the lowest operating costs of the three cases studied.

The cost of \$13.13 per thousand pounds of process steam is only slightly less (2 1/2 percent) than the \$13.46 for the coal gasification arrangement with fuel cells, waste heat recovery, and gas-fired boilers and yields an annual savings of \$15,219,000. It is about 20 percent lower than the combined cycle arrangement which amounts to an annual savings of \$154,219,000. The lower cost is attributable mainly to the higher credits for electric power and byproduct chemicals.

6.2.6 COAL GASIFICATION CONSIDERING GAS TURBINES AND FUEL CELLS WITH NO LIMIT ON ELECTRIC POWER GENERATION

For the required process steam to be generated by waste heat alone, both the gas turbine combined cycle and the fuel cell system generate considerably more electric power than is required by the industrial users. With no limit specified for electric power, the fuel cell in combination with coal gasification provides the process steam at a lower net operating cost than the combined cycle.

Although the fuel cell total annual operating cost is about 17 percent higher than the combined cycle, the net operating cost is considerably less after credit is taken for electric power, sulfur, and ammonia. On an economic basis, the fuel cell is the better choice with the cost per thousand pounds of process steam at \$9.91, versus \$14.56 for the gas turbine system. This amount represents a 32 percent savings, or \$214,236,000 per year, due primarily to the 847 MW of additional power generated.

6.2.7 FUEL CELLS WITHOUT LIMITATION OF ELECTRIC POWER AND AIR-BLOWN GASIFICATION WITH CONVENTIONAL BOILERS

Based solely on economics, with no consideration for plant ownership and ultimate use of the electric power generated, the coal gasification/fuel cell cogeneration plant utilizing only waste heat to generate process steam with no limit on electric power generated provides a net operating cost 25 percent lower than a gasification/conventional boiler arrangement having limited electric power output. The savings in operating costs results primarily from the large quantity of electric power generated.

After credit for power and byproduct sulfur and ammonia, the cost per thousand pounds of process steam is \$9.91 compared to \$13.13 for a plant that has an electric power output of 474.7 MW.

Although the total annual operating costs are almost three times as much, the net electric power output of 2786 MW provides a sufficient credit to reduce the cost of steam to

make the fuel cell scheme with no limit on electrical generation the more economical.

6.2.8 ATMOSPHERIC FLUIDIZED-BED BOILER VS FUEL CELL WITH UNLIMITED ELECTRIC GENERATION

A cogeneration plant employing the AFB to generate process and feedwater heating steam has a lower net operating cost than a coal gasification/fuel cell plant which has been sized to generate the required export steam using only waste heat with no limitation on electric power output.

Although the fuel cell arrangement generates considerably more electric power, the overall net operating cost (\$9.91 per thousand pounds of process steam) is 59 percent higher than the \$6.23 average cost of the two AFB plants studied. This represents an annual savings of \$169,363,000. The use of the average cost of the B&W and FW AFB boilers was considered justified because of the present state of the art and the differences in design philosophies of the two manufacturers.

The higher costs for the fuel cell are attributed to the high initial capital costs and its higher operating costs. Fuel input requirements for the fuel cell are approximately four times that of the AFB.

6.2.9 HIGH-TEMPERATURE GAS-COOLED REACTOR AND ATMOSPHERIC FLUIDIZED-BED BOILER AT GEISMAR

When compared with the AFB, the HTGR cogeneration plant provides a considerably lower net cost per thousand pounds of process steam. This result is similar to the results obtained when comparing the HTGR plant with the eastern coal plant.

The HTGR cost of \$4.25 per thousand pounds of steam is 32 percent less than the \$6.23 average cost for the AFB plant. This savings amounts to approximately \$91,439,000 per year, assuming 7,884 operating hours.

Cost differences are attributable to lower fuel costs, lower operating and maintenance costs, and lower auxiliary power usage, which results in higher net electric output and credit.

6.3 RELIABILITY - FOSSIL FUEL AND NUCLEAR PLANTS - ORANGE AND GEISMAR

This section examines fossil and nuclear fuel systems in an effort to ascertain the economics of adding a spare steam generating unit.

The basis of this evaluation consists of:

- Establishing operating availability for the steam generating equipment.
- Determining capital investment necessary to add a spare steam generator.
- Calculating the annual fixed charges.
- Comparing fuel costs and electric power credits for the cogeneration plant operating with and without a spare boiler and utilizing the users' existing steam generators.

Availability of the steam generators for the various arrangements was calculated using factors obtained from the Edison Electric Institute's (EEI) Report on Equipment Availability for the Ten Year Period - 1966 to 1975.⁽²⁶⁾ Operating availability (cumulative percent) and hours of planned outages were extracted on the basis of equivalent MWe rating of the cogeneration plant. These data are shown in Table 6-8.

The cogeneration plants were developed to generate the projected 1985 steam demand with backup provided by the existing facilities within users' plants. Utilizing data from the EEI report, an analysis was made to determine and compare the expected combined fuel costs and the electric power credit with and without a spare steam generating unit at the cogeneration plant. The steam flows, fuel rates, credit for power, operating hours, and costs are shown in Tables 6-9 and 6-10 for Orange and Geismar, respectively.

These tables also indicate the savings in yearly fuel costs which can be used to justify installation of a spare steam generator.

Tables 6-11 and 6-12 show the estimated capital costs for installation of the spare units and the resulting annual fixed charges at Orange and Geismar. Comparison of the fixed charge to fuel savings provides a means of evaluating the economics of spare steam generating facilities.

The reboilers within the CNSS plant are an integral part of the system and have been accounted for in the reliability analysis. Contemplated redundancy for the superheaters required in the CNSS cycle should achieve an availability of +99 percent. For this reason, they were not considered in the steam reliability analysis.

The following assumptions were used in the analysis:

Fuels - Levelized Cost Per (10)⁶ Btu

Date of Plant Startup:	1984	1985	1986
Western Coal	-	\$3.46	-
Eastern Coal	-	\$3.15	-
No. 6 Fuel Oil	\$6.34	-	\$7.80
No. 2 Fuel Oil	\$8.15	\$8.73	\$10.05
Nuclear - HTGR	-	-	\$1.56
Nuclear - CNSS	-	-	\$1.78

Credit for Electric Power

Mills/kWh (Levelized)	70.7	75.7	87.2
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Boiler Efficiencies

Cogeneration Plants	86%
Users' Plants	78%

Reactor Efficiencies

- Nuclear fuel costs were adjusted to account for reactor efficiency.

Miscellaneous

- Operating and maintenance costs were assumed to remain constant with and without spare steam generating capacity.
- Costs were escalated to the plant service date and levelized for the projected plant life.
- Steam distribution to the users with one cogeneration steam generator out of service was made to achieve the least total net cost (fuel cost less power generation credit).
- A condensate return temperature of 68°F was assumed to calculate fuel consumption of users' boilers.
- Users' boiler fuel costs were based on No. 2 fuel oil.

TABLE 6-8

AVAILABILITY FACTORS

	<u>Planned Outages</u> <u>(Hours/Year)</u>	<u>Operating</u> <u>Availability</u> <u>(Cumulative %)</u>	<u>Operating</u> <u>Availability*</u> <u>(Adjusted %)</u>
<u>Geismar</u>			
Fossil	604.31	84.3	90.5
Nuclear	773.78	81.1	89.0
<u>Orange</u>			
Fossil	464.15	89.7	94.7
Nuclear	773.78	81.1	89.0

*Adjusted operating availability when not on planned
outage = $\frac{\text{Operating Availability} \times (8,760 \text{ hr/yr})}{8,760 \text{ hr/yr} - \text{Planned Outage}}$

NOTE: An availability factor of 98 percent for the
reboilers in the CNSS plant was obtained from
Reliability Estimation for Multiunit Nuclear and
Fossil-Fired Industrial Energy Systems, Oak Ridge
National Laboratory, ORNL/TM-5837, August 1977.

TABLE 6-9

RELIABILITY ANALYSIS
ORANGE, TEXAS

Cogeneration Plant								Steam Users Plant		Total Net Cost Fuel Cost	Total Yearly Fuel Costs (Levelized)				Savings
Fuel	Units Opera- ting	Steam Flow (lb/hr)		Fuel		Electric Power		Fuel		Less Elec- tric Credit (\$/hr)	Without Spare Steam Generator		With Spare Steam Generator		
		Total Generated	To Users	Input (10 ⁶ Btu hr)	Cost (\$/hr)	Exported (MW)	Credit (\$/hr)	Input (10 ⁶ Btu/ hr)	Cost (\$/hr)		Operation (hr/yr)	\$/hr x (10) ³	Operation (hr/yr)	\$/hr x (10) ³	
Western Coal	2	3,441,382	2,195,000	3926.4	13,585	148.6	11,249	0	0	2,336	7023.54	16,407	8556.4	19,988	
	1	1,720,000	1,395,584	2411.6	8,344	77.6	5,874	1322.7	11,547	14,017	1665.26	23,342	198.6	2,784	
	0	0	0	0	0	0	0	3571.2	31,177	31,177	71.2	2,220	5.0	156	
Totals											8760	41,969	8760	22,928	19,041
Eastern Coal	2	3,441,382	2,195,000	3926.4	12,368	148.6	11,249	0	0	1,119	7023.54	7,859	8556.4	9,575	
	1	1,720,000	1,395,584	2411.6	7,597	77.6	5,874	1332.7	11,547	13,270	1665.26	22,098	198.6	2,635	
	0	0	0	0	0	0	0	3571.2	31,177	31,177	71.2	2,220	5.0	156	
Totals											8760	32,177	8760	12,366	19,811
No. 6 Oil	2	8,441,382	2,195,000	3926.4	24,893	155.2	10,973	0	0	13,920	7023.54	97,768	8556.4	119,105	
	1	1,720,000	1,395,584	2411.6	15,290	77.6	5,486	1322.7	10,793	20,597	1665.26	34,299	198.6	4,091	
	0	0	0	0	0	0	0	3571.2	29,141	29,141	71.2	2,075	5.0	146	
Totals											8760	134,142	8760	123,342	10,800
HTGR	1	3,239,239	2,195,000	3438.1	5,363	164.6	14,353	0	0	(8,990)	7104.36	(63,868)	8332.451	(74,908)	
	0	0	0	0	0	0	0	3571.2	35,891	35,891	1655.64	59,423	427.549	15,384	
Totals											8760	(4,445)	8760	(59,524)	55,079
CNSS	1	2,695,872	2,195,000	3037.2	8,167	23.8	2,075	0	0	6,092	6965.58	42,434	8332.451	50,761	
	0	0	0	0	0	0	0	3632.3	36,505	36,505	1794.42	65,505	427.549	15,608	
Totals											8760	107,939	8760	66,369	41,079

TABLE 6-10

RELIABILITY ANALYSIS
GEISMAR, LOUISIANA

Cogeneration Plant								Steam Users Plant		Total Net Cost Fuel Cost	Total Yearly Fuel Costs (Levelized)				Savings \$/hr x (10) ³
Fuel	Units Operating	Steam Flow (lb/hr)		Fuel		Electric Power		Fuel		Less Elec- tric Credit (\$/hr)	Without Spare Steam Generator		With Spare Steam Generator		
		Total Generated	To Users	Input (10 ⁶ Btu hr)	Cost (\$/hr)	Exported (MW)	Credit (\$/hr)	Input (10 ⁶ Btu/ hr)	Cost (\$/hr)		Operation (hr/yr)	\$/hr x (10) ³	Operation (hr/yr)	\$/hr x (10) ³	
Western Coal	2	9,237,178	5,840,000	10441.2	36,127	352.2	26,662	0	0	9,465	6184.77	58,539	8255.71	78,140	
	1	4,520,000	3,752,390	6477.7	22,413	163.3	12,362	3449.4	30,113	40,164	2392.26	96,083	481.98	19,358	
	0	0	0	0	0	0	0	9690	84,594	84,594	182.97	15,478	22.31	1,887	
Totals											8760	170,100	8760	99,385	70,715
Eastern Coal	2	9,237,178	5,840,000	10441.2	32,890	352.2	26,662	0	0	6,228	6184.77	38,519	8255.71	51,417	
	1	4,520,000	3,752,390	6477.7	20,405	163.3	12,362	3449.4	30,113	38,156	2392.26	91,279	481.98	18,390	
	0	0	0	0	0	0	0	9690	84,594	84,594	182.97	15,478	22.31	1,887	
Totals											8760	145,276	8760	71,694	73,582
No. 6 Oil	2	9,237,178	5,840,000	10441.2	66,197	369.7	26,138	0	0	40,059	6184.77	247,755	8255.71	330,715	
	1	4,620,000	3,752,390	6477.7	41,069	163.3	11,545	3449.4	28,147	57,671	2392.26	137,964	481.98	27,796	
	0	0	0	0	0	0	0	9690	79,070	79,070	182.97	14,467	22.31	1,764	
Totals											8760	400,186	8760	360,275	39,911
HTGR	3	8,633,414	5,840,000	9163.3	14,295	400	34,880	0	0	(20,585)	4539.056	(93,436)	7493.401	(154,252)	
	2	7,821,640	5,290,882	8301.9	12,951	366	31,915	923.7	9,283	(9,681)	3521.754	(34,094)	1134.813	(10,986)	
	1	3,910,820	2,645,441	4151.0	6,476	216.3	18,861	5330.9	53,576	41,191	662.532	27,290	126.837	5,225	
Totals											8760	(96,670)	8760	(159,531)	62,861
CNSS Boiler*	1	453,284	370,000	520	4,056	Neg.	Neg.	0	0	4,056	8142.849	33,027	8730.856	35,412	
	0	0	0	0	0	0	0	656.8	6,601	6,601	617.151	4,074	29.144	192	
	Boiler*														
Totals											8760	37,101	8760	35,604	1,497
CNSS	2	6,784,539	5,470,000	7852.4	22,232	38.4	3,348	0	0	18,884	5598.717	105,726	7899.598	149,176	
	1	4,287,240	3,499,524	4962	14,048	27.4	2,389	3382.7	33,996	45,655	2733.734	124,809	649.281	29,643	
	0	0	0	0	0	0	0	9347.1	93,938	93,938	427.549	40,163	211.121	19,832	
Totals											8760	270,698	8760	198,651	72,047

*No. 6 oil-fired boiler for 970 psia steam demand.

6.4 ECONOMICS CONSIDERING ADVANCED TECHNOLOGY CONDENSING CAPABILITIES (HTGR AND CNSS)

It was initially established that condensing capabilities were not to be considered in the design of the cogeneration plant. The basic concept was to provide the required process steam with electric power generation as a by-product. The fossil fuel fired plants are readily sized to meet the specific steam conditions, but both the HTGR and CNSS plants have excess steam generating capacity due to the standard size of available designs. However, a cursory investigation was made to determine the benefits of utilizing this excess capacity in a condensing turbine generator. In addition, the study was extended to evaluate the operating costs with the addition of a third half-size boiler in the eastern coal plants. The resulting data are shown in Table 6-13.

The basic approach taken in this analysis was to develop the differential annual operating costs attributable to the operation of the condensing facilities for each of the three types of plants. The net annual costs, which result in a savings, are the summation of the additional fuel and operating and maintenance costs and the credit for the additional net electric power generated. All of these costs are based on the projected yearly operating hours developed for the reliability analysis and shown in Tables 6-9 and 6-10.

The net annual savings were then equated to the annual fixed charges which would provide the required return on investment. Applying the appropriate fixed charge rates, escalation rates and interest during construction yielded the break-even capital costs, in January 1978 dollars, to provide the equipment necessary to utilize the condensing feature. Any cost up to this amount is economically justified.

From the results in Table 6-13, it appears that the addition of condensing facilities to use inherent excess steam capacity could be easily justified by virtue of the revenue from the additional electric power generated and lower costs for installation of the condensing facilities. On the same basis, installation and use of a spare boiler in a condensing cycle may be justified.

Looking at each type of plant separately, the CNSS cogeneration plant has a great potential for utilizing condensing because the excess steam generating capacity, which involves high capital investment, already exists due to the size of available equipment used in the basic plant design. At both Geismar and Orange, the large amount of additional power which would be generated yields a savings

more than adequate to pay for the required equipment. Generally, condensing could be utilized by the addition of a condensing turbine-generator, a condenser, condensate pumps, deaerator, feedwater heater, feedwater pumps, additional piping, a cooling water recirculating system including the cooling tower, and the related additional electrical equipment.

The order-of-magnitude cost estimates for adding condensing capabilities amount to \$44,200,000 at Geismar and \$43,400,000 at Orange and are much lower than the corresponding justified costs of \$169,224,000 and \$186,868,000 for the CNSS. Since the CNSS is a viable option, data for plants with condensing capabilities were included in the economic comparisons in Tables 6-4 and 6-5 which show results in levelized costs per thousand pounds of process steam based on 90 percent load factor. Utilizing condensing reduces CNSS process steam costs by 12 percent at Geismar and 28 percent at Orange. Although not less than the coal-fired plants, the steam costs are lower than an oil-fired cogeneration plant and the continued operation of the existing oil-fired facilities.

The capital costs justified by the HTGR are also adequate to pay for the condensing equipment which would be similar to the CNSS; but since the HTGR is not considered a viable option based on its present development status, it has not been included in the economic comparison tables.

The coal-fired plants may also justify addition of condensing facilities. However, the capital costs would be higher because no excess steam generating capacity is available and a third boiler must be provided in addition to the equipment outlined for the CNSS.

If and when the cogeneration plant becomes an actuality, whether it be nuclear or fossil fuel, it is recommended that the economics of adding condensing capabilities be reevaluated using applicable economic factors, current equipment costs, and considering institutional implications.

TABLE 6-11

RELIABILITY ANALYSIS SUMMARY - COMPARISON OF CAPITAL COSTS FOR SPARE STEAM GENERATING UNIT VS FUEL SAVINGS - ORANGE SITE

	(\$ x 1,000)			
	<u>Fossil-Fired Boilers</u>		<u>HTGR</u>	<u>CNSS</u>
	<u>Western Coal</u>	<u>Eastern Coal</u>		
Capital Cost - January 1978	74,720	73,531	229,350	184,129
Escalation	<u>27,280</u>	<u>26,846</u>	<u>96,717</u>	<u>77,647</u>
SUBTOTAL	102,000	100,377	326,067	261,776
Interest During Construction	<u>22,032</u>	<u>21,681</u>	<u>82,169</u>	<u>65,968</u>
TOTAL	124,032	122,058	408,236	327,744
Annual Fixed Charges	18,605	18,309	65,318	52,439
Annual Fuel Savings With Spare Steam Generating Unit (Levelized)	19,041	19,811	55,079	41,570
Spare Steam Generator Warranted	Marginal	Marginal	No	No

TABLE 6-12

RELIABILITY ANALYSIS SUMMARY - COMPARISON OF CAPITAL COSTS FOR SPARE STEAM GENERATING UNIT VS FUEL SAVINGS - GEISMAR SITE

(\$ x 1,000)

	<u>Fossil-Fired Boilers</u>		<u>HTGR</u>	<u>CNSS</u>	<u>CNSS Oil-Fired Boiler</u>
	<u>Western Coal</u>	<u>Eastern Coal</u>			
Capital Cost for Spare Unit - January 1978	172,325	167,748	229,350	184,129	42,244
Escalation	<u>62,916</u>	<u>61,245</u>	<u>96,717</u>	<u>77,647</u>	<u>17,814</u>
SUBTOTAL	235,241	228,993	326,067	261,776	60,058
Interest During Construction	<u>50,812</u>	<u>49,462</u>	<u>82,169</u>	<u>65,968</u>	<u>15,135</u>
TOTAL	286,053	278,455	408,236	327,744	75,193
Annual Fixed Charges	42,908	41,812	65,318	52,439	12,031
Annual Fuel Savings With Spare Steam Generating Unit (Levelized)	70,715	73,582	62,861	72,047	1,497
Spare Steam Generator Warranted	Yes	Yes	Marginal	Yes	No

TABLE 6-13

OPERATING AND CAPITAL COSTS RELATED
TO ADDITIONAL ELECTRIC GENERATION RESULTING FROM CONDENSING CAPABILITIES
(\$ x 1,000)

	<u>Geismar</u>			<u>Orange</u>		
	<u>HTGR</u>	<u>CNSS</u>	<u>Eastern Coal</u>	<u>HTGR</u>	<u>CNSS</u>	<u>Eastern Coal</u>
Condensing Capacity Availability (hr/yr)	4,539.06	5,598.71	5,149.27	5,712.97	6,965.58	6,257.1
Additional Net Electric Power (MWe)	355.6	144.8	465	76.8	128.5	174
Credit for Add. Power (\$/yr) *	(140,749)	(70,692)	(181,257)	(38,260)	(78,051)	(82,417)
Increase Annual Operating Costs						
Fuel (\$/yr)	23,288	1,704.1	82,431	6,316	18,809	37,573
O&M (\$/yr)	7,614	5,457	21,458	2,065	6,023	9,781
Net Annual Oper. Costs (\$/yr)	(109,847)	(48,194)	(77,368)	(29,879)	(53,219)	(35,063)
Capital Costs Assuming Increased Revenue for Power is Equal to Fixed Charges (\$)	686,544	301,213	515,787	186,743	332,619	233,753
Int. During Construction (\$)	138,186	60,627	91,620	37,587	66,949	41,522
Escalation (\$)	162,652	71,362	113,445	44,242	78,802	51,413
Capital Cost Justified by Added Power (January 1978 \$)	385,706	169,224	310,722	104,914	186,868	140,818

*Based on availability of steam generators from Tables 6-9 and 6-10.

6.5 SEQUENTIAL INSTALLATION OF THE HIGH TEMPERATURE GAS-COOLED REACTOR AND CONSOLIDATED NUCLEAR STEAM SYSTEM

Sequential installation of steam generators was investigated for the HTGR and CNSS at Geismar only, because the system planned at that site contains the greater number of units, indicating what could be expected for any of the other schemes considered in this study.

Options of installing only two HTGRs or three HTGRs on an extended construction schedule at Geismar were analyzed.

Under the base option, all three steam generators would be placed in service in 1986. The first alternative provides for installation of two units initially and for operation in 1986. In this case, the third unit would not be installed and the steam load not produced in the cogeneration plant would be provided by the users' facilities. (Two units provide almost 90 percent of the required heat input.)

The second alternative provides for two units to operate in 1986, with the third unit 5 years later. The third alternative considers one HTGR initially for operation in 1986, and the other two following at 5-year intervals in 1991 and 1996.

Because there are only two units involved in the CNSS plant, there was only one alternative to the base case which provides for two units initially with startup in 1986. As an alternative, one unit would begin operating in 1986 and one in 1991.

Tables 6-14 and 6-15 reflect a comparison of the operating costs of each alternate for the HTGR and CNSS, respectively. The operating costs include the annual fixed charges based on the escalated capital costs. Fuel costs and operating and maintenance costs for both the cogeneration plant and the users' facilities were combined, since sequential installation requires both the existing and cogeneration plant to provide the required 5,840,000 lb/hr of process steam. Appropriate credit was given for the net electric power generated under each option.

As shown in Table 6-14, which covers 16 years of operation, of the options which call for the installation of all three HTGRs, Alternate II has a better operating cost up until the third unit is added. At that time, the higher fixed charges that result from the construction delay cause the annual costs to exceed the base case. Alternate III spreads the capital cost over 16 years (1979 to 1996), which results in much higher operating costs due to related escalation and the higher user's fuel cost for an extended period. Based

on present worth, in 1986 dollars, the base option provides the least net operating cost when considering a three-unit plant.

The figures in Table 6-14 also show that Alternate II has lower annual operating costs until 1995 and that the total present worth is lower for the 16-year study period. After 1995, the difference in operating costs continually increases each year with the base case having the advantage. By the year 2009, the present worth of the operating costs for both plants would be equal.

The initial advantage of Alternate II is the much lower capital costs caused by the omission of the third steam generator. As the years progress, this is eventually overcome by the higher fuel costs for No. 2 oil in the users' plants and the increasing credit for the higher electric output. The initial fuel oil price is more than three times the cost of the nuclear fuel and escalates at a higher rate.

An analysis indicates that installation of two CNSS steam generators for operation in 1986 is the more economical choice. Table 6-15 shows that operating costs are always lower than for an installation on a delayed schedule. This is a result of higher cost of users' fuel oil, the low amount of net electric power generation, and the increase in fixed charges due to escalated capital cost resulting from the delay.

The data reflected on Tables 6-14 and 6-15 indicate clearly that for the conditions and economic factors associated with the study, the least present worth dollars over the life of the plant can be achieved by installing all units simultaneously. Reasons for this result are:

- Capital cost and resulting fixed charges are lower due to less escalation.
- Cogeneration fuel costs are lower.
- More credit is derived for electric power since the users' plants do not contain electric generating capabilities.

The economics of sequential installation for all the schemes and sites associated with this study may vary, but the conclusions would be the same. It should be noted, however, that these analyses are site specific and apply only under the conditions set forth in this report. Each cogeneration plant must be investigated for the specific conditions associated with its installation and operation. The addition of condensing capabilities would not affect the results since it would improve the economics of the preferred option more than the others. Sequential installations also require continued use of oil which is not in accordance with the national energy policy.

TABLE 6-14

COMPARISON OF HTGR NET OPERATING COSTS FOR COMPLETE
INITIAL CONSTRUCTION VS EXTENDED CONSTRUCTION AT GEISMAR⁽¹⁾
(Current \$ x 1,000)

	<u>Base Option</u> ⁽²⁾	<u>Alternate I</u> ⁽³⁾	<u>Alternate II</u> ⁽⁴⁾
1986	281,111	248,673	356,839
1987	276,556	246,988	368,480
1988	271,629	245,114	380,902
1989	266,265	243,034	394,157
1990	260,435	240,729	408,176
1991	254,106	295,535	279,479
1992	247,240	288,669	276,654
1993	239,792	281,221	273,519
1994	231,719	273,148	270,067
1995	222,974	264,403	266,275
1996	213,501	254,930	341,478
1997	203,250	244,679	331,227
1998	192,150	233,579	320,127
1999	180,137	221,566	308,114
2000	167,151	208,580	295,128
2001	153,111	194,540	281,088
Present Worth			
in Dollars			
as of 1/86	\$1,914,184	\$1,979,309	\$2,613,055

⁽¹⁾Costs are based on escalated values and operating at full capacity for 7,884 hours per year.

⁽²⁾Three 1200-MW HTGRs installed for operation in 1986.

⁽³⁾Two HTGRs installed for operation in 1986, the third for operation in 1991.

⁽⁴⁾One HTGR installed for operation in 1986, 1991, and 1996, respectively.

TABLE 6-15

COMPARISON OF CNSS NET OPERATING COSTS FOR
 COMPLETE INITIAL CONSTRUCTION VS EXTENDED CONSTRUCTION AT GEISMAR
 (Current \$ x 1,000)

	<u>Base Option⁽¹⁾</u>	<u>Alternate I⁽²⁾</u>
1986	311,763	432,433
1987	288,126	409,361
1988	266,486	387,877
1989	246,632	367,904
1990	228,417	349,289
1991	211,720	240,189
1992	196,379	222,261
1993	182,263	205,790
1994	169,312	190,701
1995	157,383	176,825
1996	146,446	164,123
1997	136,347	152,415
1998	127,089	141,700
1999	118,503	131,782
2000	110,634	122,708
2001	103,341	114,315
Present Worth in Dollars as of 1/86	\$3,000,841	\$3,806,673

(1) Two 1200-MW CNSS units installed for operation in 1986.

(2) First unit installed for operation in 1986, second unit for operation in 1991.

6.6 DISCOUNTED CASH FLOW ANALYSIS

The economic comparisons contained in Sections 6.1 and 6.2 were based on the revenue requirements which must be realized from the sale of steam in order to produce the minimum acceptable rate of return, taken as 10 percent. An "expense center" analysis has also been made to determine, for each fossil-fired and nuclear alternative, the net present value of the cash flow both during the construction period and for 30 years of operation. For simplicity, the start of construction for the fossil-fired alternatives has been delayed so that all alternatives have the same year of initial operation, 1986.

Tabulations of the net present value for four different fuel costs and three discount rates are shown on Table 6-16 for existing plants (fuel, operation and maintenance, working capital only), eastern coal, western coal, No. 6 fuel oil, the HTGR, and the CNSS at both Orange and Geismar. These results are compared graphically on Figures 6-2 through 6-9. Annual fuel costs were taken as 90, 100, 150, and 200 percent of the 1986 costs used in the minimum revenue requirements study. The net present worth has been determined for each fuel cost at discount rates of 10, 15, and 20 percent. Cash flow computer printouts for four different fuel costs are contained in Appendix C along with a description of the method and input used for the calculations.

Utilities' industrial rates are affected by fuel cost pass-through charges. A sensitivity analysis of the GSU electric power rates used to calculate the credit for power was not included in the scope of this study. All of the computer printouts have been included to permit interested users of this report to perform additional sensitivity analyses. These can be done with a desk calculator.

The ratios of the net present value of each alternative to the net present value for the eastern coal-fired plants are shown in Figures 6-10 and 6-11 for a fuel cost of 100 percent. The range of the discount rate has been extended to 25 percent. These curves clearly show the discount rates where the HTGR, eastern coal, and existing plants are the economic choice. The ratios are valid for steam costs, which are a linear function of the net present value.

Table 6-17 shows levelized steam costs (LSC) calculated from the following equation:

$$LSC = \frac{(1 + i)^7 (NPV)}{\frac{1}{i} \left[1 - \left(\frac{1}{1 + i} \right)^{30} \right] (S)}$$

TABLE 6-16

PRESENT VALUE OF NET CASH OUTFLOW

(1979 \$ x 10³)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS
Orange	90	10	675,068	276,386	297,952	513,997	160,794	414,206
	90	15	296,124	199,534	209,852	290,062	201,241	289,093
	90	20	150,455	151,510	157,246	189,525	194,847	220,155
	100	10	744,412	303,356	327,592	572,676	171,451	430,185
	100	15	326,035	211,487	222,991	315,369	206,102	296,213
	100	20	165,398	157,600	163,949	202,164	197,377	223,803
	150	10	1,091,144	438,205	475,769	866,051	224,739	510,072
	150	15	475,572	271,257	288,668	441,895	230,418	331,813
	150	20	240,111	188,082	197,436	265,385	210,044	242,026
	200	10	1,437,868	573,052	623,947	1,159,423	278,027	589,974
	200	15	625,109	331,033	354,348	568,425	254,727	367,414
	200	20	314,826	218,563	230,927	328,601	222,704	260,252
Geismar	90	10	1,786,205	690,414	743,527	1,326,839	429,173	1,011,118
	90	15	784,100	481,969	506,926	736,940	523,303	666,772
	90	20	398,675	361,008	374,604	477,065	507,040	493,246
	100	10	1,969,440	758,953	818,832	1,475,937	456,317	1,059,805
	100	15	863,126	512,351	540,309	801,246	535,690	688,321
	100	20	438,158	376,501	391,625	509,194	513,488	504,222
	150	10	2,885,617	1,101,670	1,195,362	2,221,418	592,029	1,303,206
	150	15	1,258,261	664,259	707,205	1,122,758	597,612	796,033
	150	20	635,581	453,960	476,730	669,835	545,739	559,097
	200	10	3,801,788	1,444,390	1,571,892	2,966,903	727,736	1,546,619
	200	15	1,653,393	816,175	874,100	1,444,276	659,536	903,755
	200	20	832,997	531,424	561,833	830,472	577,989	613,975

TABLE 6-17

LEVELIZED STEAM COST AFTER TAXES

BASED ON THE DCF ANALYSIS

(\$/1000 LB)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS	
Orange	90	10	8.06	3.30	3.56	6.14	1.92	4.95	1.20
	90	15	6.93	4.67	4.91	6.79	4.71	6.77	1.21
	90	20	6.26	6.30	6.54	7.88	8.10	9.16	1.22
	100	10	8.89	3.62	3.91	6.84	2.05	5.14	1.25
	100	15	7.63	4.95	5.22	7.38	4.82	6.93	1.26
	100	20	6.88	6.55	6.82	8.41	8.21	9.31	1.27
	150	10	13.03	5.23	5.68	10.35	2.68	6.09	1.31
	150	15	11.13	6.35	6.76	10.34	5.39	7.77	1.32
	150	20	9.98	7.82	8.21	11.04	8.73	10.06	1.33
	200	10	17.18	6.85	7.45	13.85	3.32	7.05	1.37
	200	15	14.63	7.75	8.30	13.31	5.96	8.60	1.38
	200	20	13.09	9.09	9.60	13.67	9.26	10.82	1.39
Geismar	90	10	8.02	3.10	3.34	5.96	1.93	4.54	1.43
	90	15	6.90	4.24	4.46	6.48	4.60	5.87	1.44
	90	20	6.23	5.64	5.86	7.46	7.93	7.71	1.45
	100	10	8.84	3.41	3.68	6.63	2.05	4.76	1.49
	100	15	7.59	4.51	4.75	7.05	4.71	6.06	1.50
	100	20	6.85	5.88	6.12	7.96	8.03	7.88	1.51
	150	10	12.96	4.95	5.37	9.97	2.66	5.85	1.55
	150	15	11.07	5.84	6.22	9.88	5.26	7.00	1.56
	150	20	9.93	7.10	7.45	10.47	8.53	8.74	1.57
	200	10	17.07	6.48	7.06	13.32	3.27	6.94	2.3
	200	15	14.55	7.18	7.69	12.71	5.80	7.95	2.4
	200	20	13.02	8.31	8.78	12.98	9.03	9.60	2.5
									2.7

Where LSC = steam cost levelized over the 30 years of operation, 1986 \$/10³ lb
i = discount rate
NPV = net present value, 1979 dollars from DCF analysis
S = annual process steam sendout, 10³ lb

These levelized steam costs are after taxes. The break-even price of purchased steam to give the same levelized after-tax costs are shown in Table 6-18. These prices are not exactly comparable to the levelized steam costs in Tables 6-4 and 6-5 since the fossil-fired plants tabulated there begin operation earlier, and the nuclear plant costs are levelized over 35 years.

Table 6-19 shows the figures from Tables 6-4 and 6-5 adjusted to a starting date of 1986 and 30 years of operation. For comparison, the before tax break-even purchased steam prices are shown for 100 percent fuel cost and 10 percent discount factor. The numbers are very close, showing that if industrial owners were willing to accept a 10 percent rate of return, it would make little difference economically whether they owned the cogeneration plant or bought steam from a plant owned by others.

The fixed charge rate of 15 percent is a typical value for a utility with roughly equal debt and equity financing, a minimum acceptable rate of return of 10 percent, and a 30-year plant operating life. The site-specific fixed charge rate would be on the order of 1 percent higher at Orange than at Geismar because of the effect of taxes. This would account for the slightly different ratios at the two sites.

If the hurdle rate of return were 15 or 20 percent, there would be a definite economic advantage to purchasing steam from an entity whose rate of return was limited by regulation. If this is not possible, the economic choice at a hurdle rate of return of 15 percent is between the HTGR and the coal-fired plants. Eastern coal produces the lowest cost steam at a fuel cost of 90 percent, but the HTGR has the advantage at fuel costs of 150 and 200 percent. At a fuel cost of 100 percent, the two are competitive. The CNSS with a fuel cost of 90 percent would become competitive with eastern coal plants having a fuel cost at about 150 percent.

At a hurdle rate of return of 20 percent the HTGR is not competitive with coal-fired plants except at a fuel cost above 200 percent. The CNSS with a fuel cost of 90 percent becomes competitive with coal plants with fuel costs of about 200 percent. Fuel, operating and maintenance, and working capital costs for existing oil/gas plants fall below the coal-fired plant costs at a fuel cost of 100 percent for discount rates above 20 percent. Replacement costs for existing boilers will affect this comparison, and it is questionable whether the use of oil and gas for the next 37 years is a viable option. 6-36

TABLE 6-18(1)

BREAK-EVEN PURCHASED STEAM PRICE

(1986 \$/1000 LB)

Site	Fuel Cost (%)	Discount Rate (%)	Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS
Orange	90	10	14.93	6.11	6.59	11.37	3.56	9.17
	90	15	12.83	8.65	9.09	12.57	8.72	12.54
	90	20	11.59	11.67	12.11	14.59	15.00	16.96
	100	10	16.46	6.70	7.24	12.67	3.80	9.51
	100	15	14.13	9.17	9.67	13.67	8.93	12.83
	100	20	12.74	12.13	12.63	15.57	15.20	17.24
	150	10	24.13	9.69	10.52	19.17	4.96	11.28
	150	15	20.61	11.76	12.52	19.15	9.98	14.39
	150	20	18.48	14.48	15.20	20.44	16.17	18.63
	200	10	31.81	12.69	13.80	25.65	6.15	13.06
	200	15	27.09	14.35	15.37	24.65	11.04	15.93
	200	20	24.24	16.83	17.78	25.31	17.15	20.04
Geismar	90	10	15.42	5.96	6.42	11.46	3.71	8.73
	90	15	13.27	8.15	8.58	12.46	8.85	11.29
	90	20	11.98	10.85	11.27	14.35	15.25	14.83
	100	10	17.00	6.56	7.08	12.75	3.94	9.15
	100	15	14.60	8.67	9.13	13.56	9.06	11.66
	100	20	13.17	11.31	11.77	15.31	15.44	15.13
	150	10	24.92	9.52	10.33	19.17	5.12	11.25
	150	15	21.29	11.23	11.96	19.00	10.12	13.46
	150	20	19.10	13.65	14.33	20.13	16.40	16.81
	200	10	32.83	12.46	13.58	25.62	6.29	13.35
	200	15	27.98	13.81	14.79	24.44	11.15	15.29
	200	20	25.04	15.98	16.88	24.96	17.37	18.46

(1)Based on nominal income tax rate of 46 percent at Orange and 48 percent at Geismar (See Appendix C).

TABLE 6-19

COMPARISON OF MINIMUM REVENUE REQUIREMENTS (MRR) STEAM COST FOR 10% RATE OF RETURN AND 15% FIXED CHARGE RATE WITH DISCOUNTED CASH FLOW (DCF) BREAK-EVEN PURCHASED STEAM PRICE FOR 10% DISCOUNT FACTOR

	MRR Steam Cost (\$/10 ³ lb)	DCF Break-Even Price ⁽¹⁾ (\$/10 ³ lb)	Ratio MRR/DCF
<u>Orange Site</u>			
Eastern coal	6.55	6.70	0.978
Western coal	7.06	7.24	0.975
No. 6 fuel oil	12.28	12.67	0.969
HTGR	3.33	3.80	0.876
CNSS	9.29	9.51	0.977
<u>Geismar Site</u>			
Eastern coal	6.76	6.56	1.030
Western coal	7.27	7.08	1.027
No. 6 fuel oil	12.75	12.75	1.000
HTGR	4.07	3.94	1.033
CNSS	9.40	9.15	1.027

NOTE: All figures are levelized over a 30-year period for plants beginning operation in 1986.

⁽¹⁾Based on nominal income tax rate of 46 percent at Orange and 48 percent at Geismar.

6.7 PRESENT VALUE STEAM COST

Steam costs levelized over a 30-year period beginning in 1986 are good for comparison of alternatives, but are difficult to compare with present steam costs. A present value steam cost (PVSC) may be calculated from the net present value (NPV) using the following equation:

$$PVSC = \frac{(1 + i)^7 (NPV)}{(1 + e)^7 \left(\frac{1}{i - e} \left[1 - \left(\frac{1 + e}{1 + i} \right)^{30} \right] \right) (S)}$$

Where PVSC = present value steam cost, \$/10³ lb
 NPV = net present value in 1979 \$
 i = rate of return
 e = rate of steam cost escalation
 s = process steam sendout, 10³ lb.

The present value steam cost calculated from this equation is the cost which, if escalated year-by-year for 37 years, would yield the given NPV for steam use during the 30-year period beginning in 1986. The curves in Figure 6-12 show the ratio of levelized steam cost to present value steam cost for discount rates from 10 to 20 percent and escalation rates from 5 to 9 percent. The present value steam cost is quite sensitive to the assumed rate of escalation. Table 6-20 shows the present value steam costs for the five alternative plants at Orange and Geismar for 100 percent fuel cost, 6 and 7 percent escalation, and discount rates of 10, 15, and 20 percent. For comparison, fuel and operation and maintenance costs only are shown for the existing plants net-of-taxes. At discount rates of 10 and 15 percent the coal-fired plants and the HTGR show a clearcut economic advantage over continued operation of existing plants with No. 2 fuel oil. The CNSS plant has an advantage over existing plants and new, No. 6 fuel oil plants at discount rates of 10 and 15 percent, except for one case at Orange.

TABLE 6-20

PRESENT VALUE STEAM COST NET-OF-TAXES

(1979 \$/1000 LB)

Site	Escalation Rate (%)	Discount Rate (%)	*Existing Plants	Eastern Coal	Western Coal	No. 6 Fuel Oil	HTGR	CNSS
Orange	6	10	2.73	1.35	1.46	2.56	0.77	1.92
	6	15	2.73	2.13	2.25	3.18	2.08	2.98
	6	20	2.73	3.11	3.24	3.99	3.90	4.42
	7	10	2.73	1.13	1.22	2.14	0.64	1.61
	7	15	2.73	1.83	1.93	2.73	1.78	2.56
	7	20	2.73	2.73	2.84	3.50	3.42	3.88
Geismar	6	10	2.73	1.27	1.37	2.48	0.77	1.78
	6	15	2.73	1.94	2.05	3.03	2.03	2.61
	6	20	2.73	2.80	2.91	3.78	3.81	3.74
	7	10	2.73	1.06	1.15	2.07	0.64	1.49
	7	15	2.73	1.67	1.76	2.61	1.74	2.24
	7	20	2.73	2.45	2.55	3.31	3.34	3.28

*1979 Fuel, Operation and Maintenance Costs Only, Net-of-Taxes (not derived from NPV)

PRESENT DAY TECHNOLOGY
GEISMAR & ORANGE

ADVANCED TECHNOLOGY
UNDER DEVELOPMENT
GEISMAR & ORANGE

ADVANCED TECHNOLOGY
FUTURE DEVELOPMENT
GEISMAR

FIGURE 6-1. DIAGRAM OF ECONOMIC COMPARISONS OF COGENERATION PLANTS AT GEISMAR AND ORANGE

FIGURE 6-2. NET PRESENT VALUE VS DISCOUNT RATE
AT ORANGE WITH 90% FUEL COST

FIGURE 6-3. NET PRESENT VALUE VS DISCOUNT RATE
AT ORANGE WITH 100% FUEL COST

FIGURE 6-4. NET PRESENT VALUE VS DISCOUNT RATE
AT ORANGE WITH 150% FUEL COST

FIGURE 6-5. NET PRESENT VALUE VS DISCOUNT RATE
AT ORANGE WITH 200% FUEL COST

FIGURE 6-6. NET PRESENT VALUE VS DISCOUNT RATE
AT GEISMAR WITH 90% FUEL COST

FIGURE 6-7. NET PRESENT VALUE VS DISCOUNT RATE
AT GEISMAR WITH 100% FUEL COST

FIGURE 6-8. NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 150% FUEL COST

FIGURE 6-9. NET PRESENT VALUE VS DISCOUNT RATE AT GEISMAR WITH 200% FUEL COST

FIGURE 6-10. RATIOS OF NPV (AND STEAM COSTS) FOR ALTERNATIVES TO THE NPV (AND STEAM COST) FOR EASTERN COAL AT ORANGE

FIGURE 6-11. RATIOS OF NPV (AND STEAM COSTS) FOR ALTERNATIVES TO THE NPV (AND STEAM COST) FOR EASTERN COAL AT GEISMAR

FIGURE 6-12. RATIO OF LEVELIZED STEAM COSTS TO NET PRESENT VALUE OF STEAM VS DISCOUNT RATE FOR VARIOUS ESCALATION RATES

CONCLUSIONS

SECTION 7

CONCLUSIONS

This section discusses the conclusions reached from the study, specifically addressing the following areas:

1. Site Selection
2. Heat Cycle Optimization
3. Current Technology
4. Advanced Technology - Under Development
5. Advanced Technology - Future Development
6. Plant Size and Steam Conditions
7. Plant Reliability
8. Condensing Capabilities
9. Sequential Construction - High Temperature Gas-Cooled Reactor (HTGR) and Consolidated Nuclear Steam System (CNSS)
10. Comparison With Existing Plants
11. Sensitivity
12. Energy Savings
13. Discounted Cash Flow Analysis

The conclusions reflect the assumption that all plants represent the nth of a kind. In reality, it is impossible to apply some of the concepts considered at this time. This is especially true for the CNSS, HTGR, AFB, and the coal gasification plants. However, the report attempts to define the role each might have relative to those which are available.

Further, this report does not address itself to future availability of the various fuels involved. It is assumed that all fuels will be available at a price commensurate with the anticipated normal rate of inflation.

Although two coal gasification concepts were developed with no restriction on electric power generation, the basic criterion was to provide the process steam required by the industrial users and develop electricity as a byproduct. Ultimate ownership and operation of the cogeneration plant

may have an influence on the final plant selection - the utility may be interested in maximum electric power generation and the industrial users may desire to limit it.

7.1 SITE SELECTION

An in-depth investigation of the four regions designated by DOE/GSU as having the best potential for the cogeneration concept resulted in the selection of sites at Geismar, Louisiana, and Orange, Texas. Ten sites studied within the four regions resulted in Geismar Site B and Orange Site B being ranked best according to the summation of the numerical values assigned to various siting factors. Since the variations in the total siting scores for other candidate sites are not significantly less than the selected sites, a cogeneration plant would be suitable at other sites and may be considered for future expansion planning.

It is recommended that the siting factor approach be used to determine site adequacy and suitability in connection with any cogeneration plants contemplated for the future.

7.2 HEAT CYCLE OPTIMIZATION

Analyses show that the higher steam turbine inlet pressures reduce the net operating cost due to the increased credit for electric power generation that results from the expansion of the steam through the turbines. The 2,400 psig selected as the optimum operating pressure is consistent with today's trend and technology and affords adequate operating experience.

Ideally, maximum work is obtained using an infinite number of stages of feedwater heating with a given initial and final feedwater temperature. The number of feedwater heaters used in a final plant design is determined by the incremental return on investment for the additional equipment and installation costs. The three stages of feedwater heating selected for fossil-fired plants in this study produce about 70 percent of the infinite-stage work. The four stages of feedwater heating selected for the HTGR plant produce about 80 percent of the infinite-stage work.

7.3 CURRENT TECHNOLOGY

A coal-fired cogeneration plant is recommended to meet the immediate needs of industrial users. This conclusion is based on the alternatives studied, the steam costs developed, and the present state of technology. A coal-fired cogeneration plant can be built with confidence because the technology is known and performance can be predicted with a high degree of accuracy. In addition, the

SECTION 7

CONCLUSIONS

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7-1	Annual Fuel Cost to Generate Steam in Users' Plants at Orange and Geismar Sites
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 Costs, Fuel Cost, and O&M for HTGR and
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 Costs, Fuel Costs, and O&M for the HTGR and
 Eastern Coal at Orange
- 7-5 Effect of Changes in Escalation Rate for
 Electric Power at Geismar and Orange

use of coal as a fuel agrees favorably with the present energy program directed toward utilization of coal reserves.

Based on the economic considerations shown in Table 6-1, the eastern coal-fired plants are marginally more economical than western coal-fired plants at both Orange and Geismar. Should a coal-fired cogeneration plant be contemplated, we strongly recommend a thorough investigation and establishment of prevailing economic factors. Because the choice of eastern coal over western coal is marginal, the selection of economic factors is critical to the final economic choice.

The inclusion of scrubbers in the fossil-fired cogeneration plant adds appreciably to both the capital costs and the operating costs. The following indicates the high investment required to remove the SO_2 from the flue gas:

Cost for SO_2 Scrubbers Expressed as a percent of <u>the Total Estimated Capital Cost</u>		
	<u>Geismar</u>	<u>Orange</u>
Eastern Coal	15%	14%
Western Coal	13%	13%
No. 6 Oil	16%	16%

The operating and maintenance costs for the scrubbers amount to about 25 percent of the total for western coal and about 40 percent for the oil-fired plant and eastern coal.

Maximum flexibility should be incorporated in the design of a coal-fired cogeneration plant in order to accommodate both eastern and western coals. For example, flue gas scrubbers should be sized for high-sulfur eastern coal, while the boilers, coal handling, and ash handling systems should be sized to handle the lower-Btu western coals. The increased capital cost to achieve this flexibility appears to be justified to ensure against uncertainties in fuel supply.

An eastern coal-fired cogeneration plant requires 39 percent less coal storage area than a western coal-fired plant because of eastern coals' higher Btu value. This advantage could be a prime consideration because most cogeneration plants will be located in established industrial areas.

7.4 ADVANCED TECHNOLOGY UNDER DEVELOPMENT - HIGH TEMPERATURE GAS-COOLED REACTOR AND CONSOLIDATED NUCLEAR STEAM SYSTEM

The CNSS was not suitable for either cogeneration plant because of the relationship of steam pressure and temperature limitations to users' steam requirements at Orange and Geismar. The addition of reboilers and oil-fired superheaters at both sites and an auxiliary oil-fired boiler at Geismar to generate the 970 psia, 850°F steam adds to the capital cost and complexity of the plants. In addition, electric power generation is minimal, which results in less credit for power and, consequently, a significantly higher net operating cost.

Use of the HTGR in the cogeneration plants at both Geismar and Orange would result in lower steam cost. The lower net operating costs (a result of the lower fuel cost, assuming the uranium/thorium reprocessing fuel cycle) make the HTGR very attractive. At present, however, the HTGR concept is under development and cannot be considered as an immediate candidate plant because:

- There has been minimal operating experience and limited success in the United States.
- Projected schedules and startup date are very optimistic considering present state of the art and historical licensing schedules. Long lead time is not practical for industrial expansion.
- The HTGR as a reliable source for process steam generation has not been demonstrated to industrial users.
- Technical problems within the HTGR require resolution to increase reliability.
- Fuel reprocessing is currently unauthorized.

The attractiveness of the lower steam cost suggests that problems associated with the HTGR be defined and solutions developed to increase its reliability for possible future implementation.

7.5 ADVANCED TECHNOLOGY - FUTURE DEVELOPMENT

7.5.1 ATMOSPHERIC FLUIDIZED-BED BOILERS

The cost estimate for the atmospheric fluidized-bed boilers was based on the designs of Babcock & Wilcox and Foster-Wheeler. Due to the state of the art and the magnitude of the difference in cost estimates of the two AFB

boilers, their costs were averaged for the purpose of comparison with the other alternatives. Estimated capital and operating costs were found to be very similar to those of the basic pulverized coal-fired cogeneration plants, with the cost per thousand pounds of process steam in the same general range.

The coal and limestone feeding systems and the boiler auxiliaries require slightly more electric power than the conventional pulverized coal-fired boiler so that the net electric power output is somewhat less. The lower power credit in turn increases the net operating cost. Thermal efficiencies were found to be similar to that of conventional pulverized coal-fired boilers.

Until sufficient experience has been accumulated on large-scale installations, application of the AFB boiler to cogeneration plants should not be contemplated. A major problem requiring further study and resolution involves the method of feeding coal and limestone to the boiler. Experience to date with systems that utilize numerous injection points for the coal and limestone mixture indicates the need for further work.

Present ongoing development anticipates commercial operation of large-scale utility plants before the end of the century. Since the fluidized-bed combustion of coal in a bed of limestone offers the potential for utilizing our vast low-grade coal resources in an environmentally acceptable manner, development of fluidized-bed combustion should be continued and encouraged.

7.5.2 COAL GASIFICATION

Only advanced concepts that generate the required process steam and a limited amount of electric power should be considered when comparing coal gasification plants on an equivalent basis. Utilization of the waste heat to generate required steam results in a plant which produces an abundance of electric power. This creates more or less a special case beyond the limits of the basic concept of the cogeneration plants studied. The following conclusions are therefore derived from considering plants with the same general capacities as the eastern pulverized coal-fired cogeneration plant.

It should first be noted that in all cases, the use of coal gasification requires considerably more fuel input than the basic coal-fired boiler plant. Table 7-1 lists the three comparable coal gasification concepts and compares fuel input with the basic coal-fired plant. The atmospheric fluidized-bed boiler plant, which is considered as an advanced technology, is also included in the table.

TABLE 7-1

COMPARISON OF COAL CONSUMPTION -
ADVANCED TECHNOLOGY (FUTURE DEVELOPMENT) VS
EASTERN PULVERIZED COAL-FIRED COGENERATION PLANT

<u>Cogeneration Plant</u>	<u>Coal Consumption*</u> <u>(Tons Per Day)</u>	<u>Percent Over</u> <u>Coal-Fired Plant</u>
Eastern Pulverized Coal-Fired	10,241	-
Atmospheric Fluidized- Bed (Average of Two Mfgs)	10,241	-
Air-Blown Coal Gasifi- cation With Conventional Gas-Fired Boiler	16,040	56
Oxygen-Blown Coal Gasi- fication With Conventi- onal Gas-Fired Boiler	16,294	59
Air-Blown Coal Gasifi- cation With Gas Turbines and Limited Power	15,498	51
Air-Blown Coal Gasifi- cation With Fuel Cells and Limited Power	15,021	47

*Based on 12,235 Btu/lb.

As shown by economic comparison of the gasification alternatives, the lowest estimated cost for process steam results from a cogeneration plant utilizing coal gasification and employing an advanced type of fuel cell. At the present time, forecasted development of fuel cells indicates that commercial application will not be feasible for at least 25 to 30 years. Fuel cells suitable for direct use of gasified coal are presently in the development stage, and associated cost estimates should be viewed with that in mind.

The largest fuel cell considered available in the near future is rated at 26 MWe. At this rating 10 to 12 cells would be required for a plant producing limited power. A plant providing unlimited power would require over 100 cells of this size. Another factor to consider when developing the overall plant arrangement is that fuel cells have not yet been operated on gas derived from coal. It has been assumed that this operation will be possible after further development.

While the coal gasifiers selected for this study represent commercial or near-commercial technology, development work presently in progress should result in improved processes within the next 5 to 10 years. The main disadvantage of coal gasification is the loss of heating value in converting coal to a clean gas. For the generation of electricity, conversion of coal to a clean gas is attractive because gas turbine combined cycles appear to be more efficient than the conventional condensing steam turbine cycle.

The use of a coal gasification system in conjunction with a gas turbine cycle is not suitable for cogeneration if the basic criteria require that most of the export energy be in the form of steam. Limitation of power while generating the necessary process steam requires the addition of conventional coal gas-fired boilers firing fuel gas derived from coal. In either case, with limited or unlimited power output, the cost of process steam is considerably higher than a conventional coal-fired plant.

At present, the use of clean coal gas from a gasification plant in a conventional gas-fired boiler is not yet competitive with pulverized coal firing and limestone flue gas scrubbing.

Any type of coal gasification, whether it be in conjunction with gas-fired boilers, gas turbines, or fuel cells, adds a considerable amount of operating equipment to a cogeneration plant causing increased operating and maintenance costs and reduced overall plant reliability.

In summary, use of the coal gasification process with gas turbines or fuel cells produces most of the product energy as electric power and is not suitable for cogeneration plants with process steam as the principal commodity. Operating costs for all gasification alternatives were found to be higher than the current coal technologies investigated. Fuel cells cannot be considered for any near-term, large cogeneration application because considerable development effort is required to use coal-derived gas.

7.6 PLANT SIZE AND STEAM CONDITIONS

A review of the economic comparisons for Geismar and Orange indicates that plant size does not impact the end results. The same relationships exist among each of the cogeneration plants studied for the two locations with process steam flows of 5,840,000 lb/hr and 2,195,000 lb/hr, respectively. Comparison of the net operating costs per thousand pounds of process steam results in the same economic choices for each site. The differences at the sites are very slight when expressed as percentages.

Operating cost per thousand pounds of process steam, before credit for electric power, is generally lower at Geismar, the larger of the two plants. However, the net operating costs on the same basis are slightly higher because of the credit for the electric power generated by the steam. Steam at Orange is expanded through the turbines from 2,415 psia to 290 and 640 psia and at Geismar from 2,415 psia to 290, 690, and 970 psia. Because the steam expansion is greater at Orange, more work is done and therefore more electric power is generated. The increased power credit decreases the unit cost per thousand pounds of process steam.

7.7 PLANT RELIABILITY

A review of the reliability data for pulverized coal-fired plants indicates that the availability factor directly affects the operating costs and the justification for spare or backup units. At Geismar, a spare boiler is clearly warranted, while at Orange a spare boiler is only marginally justified.

A thorough economic analysis should be made to determine the number and size of boilers that would provide the optimum reliability prior to cogeneration plant design. The use of multiple boilers improves availability but increases capital costs making reliability evaluations a delicate balance, sensitive to prevailing economic factors.

At Geismar, where there are three HTGR units each operating at about 70 percent capacity, a spare unit appears to be

marginally justified. The increase in availability does not increase the fuel savings sufficiently to offset the increase in annual fixed charges related to the higher capital costs for installation of a spare unit. At Orange, with the lower steam demand and the same capital costs, a spare HTGR steam generator could not be justified.

Although not a candidate plant, a spare steam generator for the CNSS plant can be justified at Geismar because of the increase in fuel savings. A spare CNSS unit at Orange does not yield the required return on investment and therefore cannot be justified.

7.8 CONDENSING CAPABILITIES

Providing steam turbine condensing equipment to generate additional electric power by utilizing excess steam capacity is justified by the revenue derived from the additional power if the increase in plant capital cost does not exceed the values shown in Table 6-13. This is true for the HTGR and CNSS cogeneration plants, both of which have excess capacity, at Orange and Geismar. Similarly, a third half-size boiler with steam turbine condensing equipment may be economically justified for the fossil-fired plants, provided the increased electric power output can be used or sold.

In both the nuclear and fossil fuel cases, the addition of steam turbine condensing capability provides additional electric power output. The addition of steam generation for use in condensing facilities in a fossil fuel cogeneration plant offers further benefits by creating a backup steam source and contributing toward improved plant reliability. Availability of steam for process is, however, contingent upon the electrical load being interruptible.

A detailed study of condensing using the excess steam generating capacity in the CNSS plants confirmed that the added capital and operating costs are more than justified by the credit received for the resulting increase in power generation. Applying this net gain to costs, however, does not reduce the steam costs sufficiently to compete with the coal-fired plants. It does make it more attractive when comparing costs with an oil-fired cogeneration plant or continued operations of the present facilities.

At Orange, use of the condensing concept reduces steam cost from \$9.86 to \$7.10 per thousand pounds, or 28 percent. Use of condensing in the CNSS plant at Geismar would reduce costs only 12 percent, from \$10.00 to \$8.80.

Generally speaking, utilization of condensing equipment is appropriate for a cogeneration plant owned and operated by

parties having a need or market for electric power. Industrial users are usually interested in generation of process steam. Installation of condensing equipment should be evaluated for a particular plant site, taking into account the specific steam and power requirements and ownership.

7.9 SEQUENTIAL CONSTRUCTION OF THE HIGH TEMPERATURE GAS-COOLED REACTOR AND CONSOLIDATED NUCLEAR STEAM SYSTEM

Extending the construction period of the nuclear plants at Geismar by installing the reactors at 5-year intervals was studied, and it was concluded that the accumulated operating cost over the life of the plant is higher than with simultaneous installation. Higher operating costs result for every year by installing one HTGR at a time. Installing two HTGRs initially yields lower costs for the first 5 years but after the third unit is added, the costs reverse. Using present worth, the total is higher than simultaneous installation of three units.

Another option studied considers installation of only two HTGRs initially and totally omitting the third. Compared to the base case, this alternate has lower annual operating costs until 1995. After that time, the cost difference continually increases in favor of the three-unit plant, and, by the year 2009, the total present worth of the operating costs for both plants would be equal. Over the full life of the plant, the base case would still have the lower total present worth. The alternate also has the disadvantage of using fuel oil to make up the steam deficiency of the cogeneration plant.

The addition of condensing capabilities would not affect the conclusions for sequential installations. It would make the base case an even better option since additional credit for power would occur at the initial startup. Addition of condensing would improve the position of the three HTGRs when compared with only two.

Installation of one CNSS unit at a time is of no advantage because annual savings in operating costs of a plant with two units initially exceeds the fixed charges incurred for the second CNSS. Installation of two CNSSs initially results in lower operating costs for each year over the life of the plant.

7.10 COMPARISON WITH EXISTING PLANTS

Tables 6-4 and 6-5 include steam costs for the existing plants based on estimated fuel, operating, and maintenance costs. These costs assume burning No. 2 fuel oil in existing boilers and generation of steam at current conditions. No scrubber costs or fixed charges are included, and credit for power is not applicable.

Even without scrubber operating costs and the fixed charges for existing equipment or modifications for conversion to allow for oil firing, the net cost of process steam is generally higher for the existing plants than for the cogeneration plants with a 10 percent rate of return. The following comparisons of the cost per thousand pounds of process steam indicate that cogeneration plants can provide steam at a cost much lower than the existing plants using No. 2 oil:

	<u>Comparison of the Cost of Steam (\$/1000 lb)</u>			
	<u>ORANGE</u>		<u>GEISMAR</u>	
	<u>Existing Plants</u>	<u>Cogeneration Plant</u>	<u>Existing Plants</u>	<u>Cogeneration Plant</u>
Eastern Coal	\$13.90	\$ 6.19	\$11.83	\$ 6.39
Western Coal	\$13.90	\$ 6.69	\$11.83	\$ 6.88
No. 6 Fuel Oil	\$12.99	\$10.76	\$11.06	\$11.17
HTGR	\$15.98	\$ 3.45	\$13.60	\$ 4.25
CNSS without Condensing	\$15.98	\$ 9.86	\$13.60	\$10.00
CNSS with Condensing	\$15.98	\$ 7.10	\$13.60	\$ 8.80

7.11 SENSITIVITY

The results shown in Tables 6-4 and 6-5 and other sections of this report involve specific economic assumptions. Some of these assumptions, such as load factor and escalation rates, have been forecast on the basis of historical data and/or best available information. Additionally, estimated costs are of the order of magnitude type.

Figures 7-1 through 7-5 were developed to indicate the effect of certain variables on the net cost of steam. Figure 7-1 reflects users' fuel costs when generating process steam at Geismar and Orange facilities burning No. 2 fuel oil.

Figure 7-2 shows how the cost of steam increases for the CNSS, HTGR, and eastern coal at Orange and Geismar when the load factor is assumed lower than 90 percent (equivalent to 7,884 hours per year). For example, HTGR steam costs at Orange increase from \$3.45 to \$6.82, or almost 100 percent, using a 60 percent load factor. Steam cost of an eastern coal-fired cogeneration plant at Orange increases from \$6.19 to \$8.29, reflecting a 34 percent increase.

Figures 7-3 and 7-4 reflect the changes in cost caused by deviations from the base figures for capital, operating and maintenance, and fuel costs for Geismar and Orange, respectively. These curves show the effect for the CNSS, HTGR, and eastern coal. It can be seen that changes in fuel, operating, and maintenance costs of an HTGR at Geismar have little impact on steam costs. Capital costs of the HTGR must increase more than 30 percent before net steam costs equal those of eastern coal. Changes in cost of fuel have more effect than changes in capital cost in an eastern coal plant. Changes for each of the items can be noted from the graphs and the total effect on steam cost determined by summing the changes in cost.

Figure 7-5 shows the effect on changes in the escalation rate of credited electric power when determining net steam costs. At both Geismar and Orange, the cost per kWh was escalated at a rate of 11 percent to 1985 and 7 percent from 1985 over the life of the plant, based on present economic assumptions. Again, figures represent the economically more attractive HTGR and eastern coal and the CNSS with and without condensing capabilities.

Another variable that would have a substantial effect on steam cost is the rate of escalation assumed for fuel. As an example, the following shows how steam costs would change for the eastern coal plant for escalation rates of 2 to 16 percent with the rate of return held at 10 percent. A rate of 6 percent was used in the base calculations for Tables 6-4 and 6-5.

Effect of Fuel Escalation Rates on Steam Costs For
Eastern Coal-Fired Plants

<u>Escalation Rate</u> (%)	<u>Steam Cost - \$/1000 lb</u>	
	<u>Geismar</u>	<u>Orange</u>
2	4.51	4.31
4	5.32	5.12
6	6.39	6.19
8	7.87	7.68
10	9.91	9.72
12	12.79	12.60
14	16.87	16.68
16	22.69	22.51

Although there is an interrelationship between coal prices and power costs, the above analysis holds power cost at a constant price. In reality, the cost of power would have to be similarly escalated to determine net steam costs.

It is apparent that the basic assumptions have a great impact on the results. A change in the escalation rate from 6 to 10 percent causes a 55 percent increase in the cost of steam. For a range of escalation rates from 2 to 16 percent, the fuel costs are 40 to 80 percent of the total operating costs before credit for power.

7.12 ENERGY SAVINGS

All of the fossil-fired cogeneration plants, categorized as current technology, provide a global saving in energy at both sites when compared to maintaining the present steam generating facilities and continuing to purchase all electric power. Similarly, the nuclear plants also yield a reduction in total energy input. Energy savings result from higher operating efficiencies and the lower heat chargeable to cogenerated electric power.

Only the AFB provides an energy saving among the cogeneration plants considered as advanced technology, future development.

Table 7-2 shows the expected energy savings, or loss, expressed in Btu x 10⁶/hour for each of the alternative plants with limited electric power output.

At Orange, the fuel oil input for steam generation by the existing industrial facilities amounts to 25,000 gph based on a heating value of 142,000 Btu/gallon. At Geismar, the required fuel oil input is 70,000 gph. This amount of oil would be replaced if either a coal-fired or HTGR plant were implemented. Because oil is used as the fuel for the superheaters and boilers required in the CNSS plants, oil

TABLE 7-2

ENERGY SAVED BY COGENERATION - Btu x 10⁶/hour

Cogeneration Plant	Energy Input For Existing Operations			Energy Input by Cogen-eration Plant	Energy Savings (Loss)	
	For Steam Generation	By GSU to Generate Electric Power*	Total		Btu x 10 ⁶ /hr	Percent
<u>Orange</u>						
Eastern and Western Coal-Fired	3603.1	1587.5	5190.6	3926.4	1264.2	24.4
No. 6 Fuel Oil-Fired		1658.0	5260.5	3926.4	1334.7	25.4
HTGR		1758.4	5361.5	3438.1	1923.4	31.9
CNSS		254.3	3857.4	3037.2	820.2	21.3
<u>Geismar</u>						
Eastern and Western Coal-Fired	9963.3	3762.6	13,725.8	10,441.2	3284.6	23.9
No. 6 Fuel Oil-Fired	9963.3	3949.5	13,912.8	10,441.2	3471.6	25.0
HTGR	9963.3	4273.2	14,236.5	9,163.5	5073.0	35.6
CNSS	9963.3	410.2	10,373.5	3372.4	2001.1	19.3
Foster-Wheeler AFB	9963.3	3678.2	13,641.5	10,395.3	3246.2	23.8
Babcock & Wilcox AFB	9963.3	3631.2	13,594.5	10,460.7	3133.8	23.0
Coal Gasification with						
Conventional Boiler (Air-Blown)	9963.3	5071.2	15,034.5	16,354.1		(8.8)
Conventional Boiler (Oxygen-Blown)	9963.3	5092.6	15,055.9	16,613.1		(10.3)
Combined Cycle (Limited Electric)	9963.3	3760.4	13,723.7	15,801.3		(15.1)
Fuel Cell (Limited Electric)	9963.3	3760.4	13,723.7	15,315.2		(11.6)

*Energy input required to generate the same net output as cogeneration plant. Based on GSU average of 10,683 Btu/kW as reported in Electric Light and Power, August 1978.

savings would be reduced by 3,200 gph at Orange and 9,800 gph at Geismar.

If it is assumed that the cogenerated electrical power from coal replaces the output from an oil-fired utility power station, then an additional savings of fuel oil would result. At Orange this would amount to about 11,000 gph; while at Geismar it would be around 26,000 gph.

7.13 DISCOUNTED CASH FLOW ANALYSIS

All of the foregoing comparisons and conclusions are based on levelized steam costs that were developed using a fixed charge rate of 15 or 16 percent, which provides for a 10 percent rate of return. This is basically the minimum revenue requirements methods common to utility-type economic evaluations. The analyses summarized in Tables 6-4 and 6-5 also use a specific year for starting all construction, which means that the initial operating dates are different for the various options because of varying construction periods.

Because the owner of a cogeneration plant could be other than a utility, an expense center analysis has been made to determine steam costs with rates of return of 10, 15, and 20 percent. For simplicity, the start of construction for each option was timed so that initial operation begins in the same year. Also, a 30-year period of plant operation was used in all cases. For further evaluations, the effects of varying the fuel costs was determined. All net present worth values generated are in 1979 dollars.

From the resulting data presented in Figures 6-2 through 6-12 and tabulated in Tables 6-16 through 6-20, the reader can make evaluations based on his own selected rate of return and projected fuel costs. The effect of varying the escalation rate is illustrated in Figure 6-13. Some conclusions made apparent by the developed cost data are as follows:

1. The levelized steam costs developed by the minimum requirements method, when adjusted for the same startup date and operating life, are comparable to the results of the DCF analysis at a discount rate of 10 percent when allowances are made for applicable taxes. The conclusions in Sections 7.3 and 7.4 apply.
2. At a discount rate of 15 percent, the comparison between the various cogeneration options remains the same as of 10 percent based on steam costs for fuel costs at 150 and 200 percent. For fuel costs at 90 and 100 percent, the HTGR loses most or all

of its advantage over eastern coal. With this exception, the HTGR provides the lowest steam cost. After that, the order is eastern coal, western coal, the CNSS, and No. 6 fuel oil.

3. At a 20 percent discount rate, eastern coal and western coal steam costs are the lowest. The other plants change order with the various fuel costs.
4. The net present value of fuel, operation and maintenance, and working capital costs for the existing plants using No. 2 fuel oil fall below eastern and western coal-fired cogeneration plants at fuel costs of 90 and 100 percent as the discount rate exceeds 20 percent. Inclusion of capital costs for new oil/gas fired boilers for expansion and replacement would move the break-even discount rate to higher values. However, since industry historically requires hurdle or threshold rates of return as high as 25 to 30 percent, the analysis presented here explains why there is little action in the field of industrially-owned coal-fired cogeneration plants at this time.
5. There is a definite economic advantage for an industrial user to purchase steam from an entity having a rate of return limited by regulation.

FIGURE 7-1. ANNUAL FUEL COST TO GENERATE STEAM IN USERS' PLANTS AT ORANGE AND GEISMAR SITES

FIGURE 7-2. EFFECT OF CHANGES IN LOAD FACTORS AT ORANGE AND GEISMAR SITES

FIGURE 7-3: EFFECT OF CHANGES IN ESTIMATES FOR CAPITAL COSTS, FUEL COST AND O&M FOR HTGR, CNSS AND EASTERN COAL AT GEISMAR

FIGURE 7-4. EFFECT OF CHANGES IN ESTIMATES FOR CAPITAL COSTS, FUEL COSTS AND O&M FOR THE HTGR, CNSS AND EASTERN COAL AT ORANGE

FIGURE 7-5. EFFECT OF CHANGES IN ESCALATION RATE FOR ELECTRIC POWER AT GEISMAR AND ORANGE

SECTION 8

PLANT SCHEDULE AND IMPLEMENTATION

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SECTION 8

PLANT SCHEDULE AND IMPLEMENTATION

8.1 CONSTRUCTION SCHEDULES

This section contains the construction schedules for the cogeneration plants from the conceptual engineering phase to commercial operation. The schedules, which are divided into quarterly increments, show a total elapsed time of 6 years for the coal-fired plants and 7 years for the nuclear plants. Schedules reflecting both the Orange and Geismar sites are as follows:

<u>Drawing No.</u>	<u>Cogeneration Plant</u>
12977-PSN-1	Coal-Fired
12977-PSN-2	Consolidated Nuclear Steam Supply (CNSS)
12977-PSN-3	High Temperature Gas-Cooled Reactor (HTGR)

These drawings are included in this section as Figures 8-1 to 8-3.

The coal-fired plant schedule was developed from in-house data. Babcock & Wilcox and General Atomic Company supplied the basic data from which the construction schedule was developed for the CNSS and HTGR, respectively.

8.2 PROPOSED STRATEGIES FOR IMPLEMENTATION OF PLANT SYSTEM CONCEPTS

8.2.1 IMPLEMENTATION - COAL-FIRED PLANT AT ORANGE

Construction of the coal-fired plant is feasible without technical constraints and could start immediately.

The projected steam flows indicate a minimum industrial expansion from 1985 to 1990. It was assumed that the users' present steam generating facilities contain adequate capacity to serve as backup after completion of a cogeneration plant. During the construction period of the plant, their facilities must be operated and maintained on the premise that the boilers are to be available for future intermittent use. Where necessary, the users' boilers must be modified for firing No. 2 fuel oil, unless continued use of natural gas is permitted for standby service. These changes should be made after startup of the cogeneration plant.

FIGURE 8-1

CONSTRUCTION SCHEDULE
FOR COAL-FIRED PLANT

FIGURE 8-2

CONSTRUCTION SCHEDULE
FOR CNSS PLANT

LEGEND:

PSAR = PRELIMINARY SAFETY ANALYSIS REPORT
 NRC = NUCLEAR REGULATORY COMMISSION
 EPA = ENVIRONMENTAL PROTECTION AGENCY
 ER = ENVIRONMENTAL REPORT
 FSAR = FINAL SAFETY ANALYSIS REPORT
 EIA = ENVIRONMENTAL IMPACT ASSESSMENT
 EIS = ENVIRONMENTAL IMPACT STATEMENT
 I&C = INSTRUMENTATION & CONTROL
 PCRV = PRESTRESSED CONCRETE REACTOR VESSEL

NOTES:

- ONE HTGR IS REQUIRED AT THE ORANGE SITE & THREE HTGR'S ARE REQUIRED AT GEISMAR SITE.
- FOR EVALUATION SIMPLICITY WE HAVE USED IDENTICAL COMMERCIAL OPERATING DATES FOR EACH PLANT & ASSUMED THAT ALL STEAM GENERATORS WILL BE ERECTED SIMULTANEOUSLY.
- COMMERCIAL OPERATION 1986.
- CONSTRUCTION SCHEDULE BASED ON G.A. SCHEDULE FOR AN NM OF A KIND HTGR STEAMER.
- CONSTRUCTION SCHEDULE ASSUMES 6 MONTHS OF ENVIRONMENTAL DATA TO SUPPORT ER & PSAR PREPARATION.
- CONSTRUCTION SCHEDULE ASSUMES FULL AVAILABILITY OF MATERIAL, MANPOWER & CONSTRUCTION EQUIPMENT.
- NO ALLOWANCE HAS BEEN MADE FOR TIME LOSS DUE TO STRIKES, FLOOD, OR WEATHER.

FIGURE 8-3
 CONSTRUCTION SCHEDULE
 FOR HTGR STEAMER

COGENERATION FEASIBILITY STUDY
 CONSTRUCTION SCHEDULE
 FOR
 GENERAL ATOMIC HTGR STEAMER
 COGENERATION PLANT
 AT
 ORANGE, TEXAS & GEISMAR, LOUISIANA
 12977 - PSN-3

The reliability analysis shows that a spare 50-percent capacity boiler can only be marginally justified. However, it is recommended that a review be made during the initial design phase to consider three or more boilers to provide the capacity required. Multiple, small boilers improve the overall reliability and permit smaller increments of expansions in the future either to meet additional steam requirements or to provide spare capacity.

The inclusion of condensing capabilities and related additional steam generating equipment is only applicable if cogeneration plant ownership or legal agreements allow utilization of the excess electric power.

8.2.2 IMPLEMENTATION - COAL-FIRED PLANT AT GFISMAR

Current technology permits design and construction of a coal-fired cogeneration plant to begin immediately with steam generation available in 6 years after start of construction.

The process steam capacity of the cogeneration plant at this location was established to equal the projected 1985 steam demand. This means that when construction is completed, the plant will operate at full capacity with no excess for standby or expansion. Steam consumption between 1985 and 1990 is projected to increase 18.5 percent.

During the cogeneration plant construction period, the projected steam requirements indicate that certain users must add to their facilities to meet increasing demands. The users would therefore have 100-percent backup available when the cogeneration plant goes into operation.

On the basis of the reliability study it was determined that a spare 50-percent capacity boiler could be justified. It is therefore recommended that an investigation be made during the initial design stage of the cogeneration plant to optimize the number and size of the boilers. For a further improvement in reliability, more than three boilers should be considered. The economic analysis should consider potential expansions and spare capacity requirements.

Other areas that should be investigated during the initial design phase are:

- Size of turbine generators, considering peak loads, minimum flows, and anticipated expansion.
- Condensing capabilities, if additional electric power can be utilized.
- Feedwater heating equipment size, number of heaters, need for spares and reliability.

8.2.3 IMPLEMENTATION - HIGH TEMPERATURE GAS-COOLED REACTOR

Since the HTGR cogeneration plant can provide process steam at the required pressures and temperatures and fuel costs are low, it is economically very attractive. However, based on experience to date within the United States, the HTGR has not progressed technically to a point to be considered as a viable option for a cogeneration plant in an industrial complex. Although classified here as advanced technology under development, the HTGR should be considered more as future technology comparable to the status of the atmospheric fluidized-bed concept.

An HTGR system, whether it be a steam cycle or a gas turbine or combined cycle, may not be technically acceptable for another 10 to 20 years. Development of the HTGR for utility use may ultimately produce a system that has applicability for cogeneration.

8.2.4 IMPLEMENTATION - CONSOLIDATED NUCLEAR STEAM SUPPLY

The specific steam requirements at Orange and Geismar diluted the attractiveness of the CNSS for the cogeneration plants in this study. The need for oil-fired auxiliary equipment increased capital and operating costs, and credit for electric power was minimal due to its limitation on steam pressure.

It should not be assumed from this that the CNSS is not suitable for other potential cogeneration applications. The operating conditions, which penalize it in this study, may be acceptable where superheated or higher pressure steam is not required. Cogeneration plants can be considered for providing heating steam for hospitals, residences, and commercial areas. Some industrial complexes may also have needs within the capabilities of the CNSS. The CNSS is further advanced than the HTGR in the United States and its use should be evaluated for application at specific sites.

8.2.5 IMPLEMENTATION - ATMOSPHERIC FLUIDIZED-BED BOILERS

Fluidized-bed combustion of coal in a bed of limestone offers the potential for utilizing our vast coal resources in an environmentally acceptable manner for cogeneration as well as electric utility power generation. The operating efficiencies are similar to that of pulverized coal-fired boilers; in addition, the AFB boiler has the capability of using low-ranked coals.

As mentioned in Section 4.4.3.1.6, several development programs are presently in progress. Considering the potential benefits of the AFB, it appears that present efforts are justified and they should be continued to develop large-scale installations in the near future.

8.2.6 IMPLEMENTATION - COAL GASIFICATION

The coal gasification processes developed and discussed in this study are not suited to meet the specific requirements of the subject cogeneration plants. Therefore, further development of these processes cannot be justified by this study.

There are ongoing studies to improve the coal gasification process and to develop both the combined cycle and fuel cell, so that advancements in these areas may warrant future review and consideration. Specific steam and electric requirements have a great influence on the adaptability of the combined cycle and fuel cell concepts which have the capability of producing large amounts of electric power.

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VALCO, INC., DALLAS, TEXAS
VALCO, INC., DALLAS, TEXAS

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APPENDIX A

APPLICATION OF SITING CONSIDERATIONS TO CANDIDATE SITES

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APPENDIX A

APPLICATION OF SITING CONSIDERATIONS TO CANDIDATE SITES

1 NORTH BATON ROUGE - SITE A/B

1.1 TECHNICAL/ENGINEERING CONSIDERATIONS

1.1.1 Site Preparation

Site A at North Baton Rouge is a flat area containing heavily wooded sections and low vegetation. Near the center of Site A is an abandoned settling basin previously used by Kaiser Chemical Company. Prior to 1973, effluent from their plant operations was pumped to this basin. A treatment plant has been installed and the settling basin has reportedly not been used since 1973. It is probable that subsurface soil conditions in the immediate vicinity of the abandoned settling basin have been affected by chemical constituents of previous effluent seepage. Such contaminated soils, if they exist, would likely cause wide variations in shear strength and settlement characteristics. Because of concern for the bearing capacity and settlement of any facilities constructed in the vicinity of the abandoned settling basin, a large excavation is probable at Site A, even if it were to be used only for coal storage.

Site B, which lies between the existing Louisiana Station and the Mississippi River, is covered by low scrub vegetation. Its topography is believed to denote previous construction activities.

Groundwater levels at both sites will be influenced by Mississippi River levels. Thus, seasonal fluctuations in river levels would cause corresponding changes in groundwater levels at Site A/B. Groundwater levels within several feet of existing ground surface are quite common and, accordingly, excavations at either site would require dewatering. Pump tests are required to properly design temporary dewatering systems for construction. Concern for falling groundwater levels in the Baton Rouge area initiated the formation of the Capital Area Groundwater Conservation Commission (CAGCC) to regulate groundwater withdrawal in that area. Although dewatering of any excavation would only be temporary, the CAGCC would undoubtedly want to assess the impact of any dewatering system on existing wells in the vicinity of Site A/B.^(1,2)

Excavated material from either site could be used for grading and/or construction of retaining dikes around any oil tanks or to control runoff from coal storage piles. The depth to firm bearing strata at the North Baton Rouge sites would be significantly smaller than the Geismar sites. It

appears that approximately 50 feet of excavation might be required in the North Baton Rouge region for a nuclear plant, whereas in the Geismar region, the depth of excavation to suitable firm bearing soil might be as great as 90 feet.

Matrix ratings of 7 and 8 were assigned to nuclear and fossil plants, respectively. These values reflect the difficulty of dewatering and problems associated with the suspected presence of chemical effluents in the former settling basin vicinity.

1.1.2 Proximity to Load Demand

The proposed site is centrally located and was given the maximum rating of 25 for both types of plants.

1.1.3 Water Availability

The Mississippi River is the potential source of water. The low-water flow of the Mississippi near Baton Rouge is approximately 100,000 cfs. The average flow is about 419,000 cfs with a maximum historical flow of 1,248,000 cfs. As indicated in Section 3.2.2.1.3, the river has ample water available for the needs of a power plant. In light of this information, we have assigned a matrix rating of 20 to nuclear and fossil plants.

1.1.4 Highway, Rail, and Water Access

Interstate Highways 10 and 12 are the principal arteries of the region's highway system. Interstate 10 connects the cities of New Orleans, Baton Rouge, and Lafayette; Interstate 12 trends in an east-west direction from Baton Rouge to Alabama. Locally, the principal routes are U.S. Highway 61, and Interstates 110 and 190. U.S. 61 extends from Baton Rouge to St. Francisville and north to Natchez, Mississippi. U.S. 190 extends in an east-west direction across the state and passes through Baton Rouge. State and county roads serve the remainder of the region.

The Illinois Central, Texas and Pacific, Louisiana and Arkansas, and South Shore Railroads serve the Mississippi region with Baton Rouge as the major rail center. The main line of the Illinois Central Railroad borders the eastern edge of the site.

The Mississippi River qualifies as a navigable waterway and handles considerable annual tonnage of barge traffic. Also, ocean freighters come as far north as the Baton Rouge Port. The proximity of this candidate site to a bend in the river and the resulting potential hazards to river navigation raise questions as to whether the site could utilize barge

unloading of fuel. Further detailed studies would be required to affirm the suitability of the site for barge unloading. A matrix rating of 5 was assigned to nuclear plant siting; a matrix rating of 20 was given to fossil plant siting due to the uncertainty of fuel unloading by barge.

1.1.5 Foundations

As indicated in Site Preparation, the depths to firm bearing strata are important to determine the depth of excavation for nuclear plants or the required length of piles for fossil power plants. Existing soils to depths of about 50 feet at Sites A and B are not capable of satisfactorily supporting the relatively heavy structure loads typical of either fossil or nuclear power plants. In the case of nuclear power plants, the near-surface soil strata in the North Baton Rouge area are cohesive silts and clays.^(1,3) These soils are not susceptible to liquefaction during seismic events; however, long-term compressibility precludes such soils being left in place. In fossil power plants, these softer silts and clays must be excavated or bypassed in the form of piles or caissons to carry the heavy structural loads down to firm bearing strata.

If it were desirable to situate a nuclear plant at an elevation higher than the required bottom of excavation, compacted granular backfill could be placed between the excavation grade and required foundation grade. Granular backfill suitable for this purpose would have to be obtained offsite. The excavated silts and clays could theoretically be replaced and compacted to a sufficiently high density. However, the logistics of excavating and stockpiling the cohesive silts and clays until they could be replaced in the excavation would probably be more expensive than utilizing offsite granular borrow sources.

Foundation design loads of 50 to 60 tons for 50-foot long step taper or precast concrete piles are typical for the Baton Rouge vicinity.⁽³⁾ Alternately, drilled caissons might prove to be more economical; the cohesive nature of the foundation soils in the North Baton Rouge region and the relatively shallow depths to firm bearing strata permit the economic competitiveness between pile and caisson type foundations. This situation is in contrast to Geismar, for example, where pile foundations are more feasible and cheaper than caissons.

Matrix ratings of 12 and 10 for nuclear and fossil plants, respectively, were assigned primarily due to the relatively shallow depths to firm bearing strata.

1.1.6 Water Supply Systems

The topography of the site suggests that special or unusual construction features would not be required for the water supply systems. The site is bordered on the west by the Mississippi River. Plant-river distance would be approximately 600 feet. A maximum matrix rating of 10 has been assigned for both nuclear and fossil plants.

1.1.7 Land Costs

The adjacent areas are well developed industrially, commercially, and residentially; thus, high land costs would prevail. For these reasons a matrix rating of 2 was assigned to both nuclear and fossil plants.

1.1.8 Steam Supply/Demand Match

In common with all sites, Site A/B was rated 10 for Steam Supply/Demand Match for a fossil plant. The steam demand lies between what could be supplied by a commercial LWR and an intermediate-size LWR, so the site was rated 10 for a nuclear plant.

1.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

1.2.1 Wastewater Impact

The wastewaters from the power plant will have no adverse effect on water quality. A National Pollutant Discharge Elimination Statement (NPDES) will be filed and required limits complied with for the Steam Electric Power Generating Point Source Category.⁽⁴⁾ The wastes will also meet Louisiana water quality criteria. Since the Mississippi River has a large volume of water, water consumption will not be adverse even during the low-water flow in the river (see Cooling Water Impact). Matrix ratings of 5 and 10 were assigned for nuclear and fossil plants, respectively.

1.2.2 Cooling Water Impact (Nuclear)

Due to the high flow of the Mississippi River, cooling water requirements would produce a negligible effect on the river, if emergency cooling were required.

The low water flow of the Mississippi is approximately 100,000 cfs (Section 1.1.3). With once-through emergency core cooling requiring a flow of approximately 120 cfs, the net temperature rise of the river would be an imperceptible 0.012 F. A matrix rating of 5 was assigned.

1.2.3 Land Use

The site area is commercially and industrially zoned. A potential land use problem may exist since the site is contiguous on one side with a college campus. However, because of earlier industrial land use, the potential problem is expected to be minimal. A matrix rating of 6 was assigned for both plants.

1.2.4 Land Requirements

The North Baton Rouge site consists of two parcels of land. Subsite A, the northern parcel, contains 220 acres and Subsite B, the southern parcel, contains 30 acres. They are separated by a distance of approximately 8,400 feet. The A/B site was evaluated collectively in this category providing a matrix rating of 6 for fossil and 20 for nuclear plants.

1.2.5 Geology

A slump fault passes under Glen Oaks High School several miles due east of proposed Site A.⁽²⁾ The general trend of the slump fault is east-west. Although there is no onsite evidence that this fault extends west from the Glen Oaks High School vicinity to Site A, it is probable that the NRC would postulate the extension of the fault below Site A. Extensive onsite and offsite geologic investigations would be required to address this question.

The slump fault is insignificant from a seismologic standpoint since slump faults are not determined to be "capable" sources of generating earthquakes.⁽⁵⁾ However, any postulation of the existence of the slump fault would concern plant design (fossil or nuclear) as it relates to differential settlements. Should the slump fault extend below Site A, particular attention must be focused on designing for possible differential displacements and/or tilting of adjacent foundations.

Large-scale withdrawal of groundwater as a supply source in the Baton Rouge area implicates subsidence as a major concern at both Sites A and B.^(2,5) Predictions of 4 to 8 feet of subsidence in the general Baton Rouge area during the period 1970 to 1990 are common. Subsidence caused by extraction of oil and water typically results in relatively widespread settlements so that future subsidence at Sites A and B would be fairly uniform at each site. Thus, differential settlements between adjacent facilities would not be significant; however, protecting the sites against Mississippi River floods and plant system hydraulics may be adversely affected by a uniform settlement of the plant sites by several feet.

Stratified deposits of silty clays and clayey silts with occasional lenses of silty fine sands are likely to underlie both sites. This geologic profile is typical of petrochemical plant sites bordering the Mississippi River in the North Baton Rouge area.⁽³⁾ Of significance in the area is the absence of typical soft clay (Pleistocene) layers that occur at many southern Mississippi River sites. Accordingly, depths to firm bearing strata are shallower than the Geismar sites, for example, requiring shorter pile or caisson lengths for a fossil plant or shallower excavation for a nuclear plant.

In accordance with the above reasons, matrix ratings of 20 and 10 were assigned for nuclear and fossil plants, respectively, at the North Baton Rouge site.

1.2.6 Hydrology

When flooding duration is limited, the construction of impervious dikes higher than flood level might be acceptable to the NRC for a nuclear plant located on the floodplain of the Mississippi River. The only adequate protection against extended flooding would be a grade elevation higher than the level of the dikes or extensive flood protection in plant design in order to comply with strict NRC siting criteria. Fossil-fueled plant flood design criteria are less severe. Matrix ratings of 20 and 15 were assigned for nuclear and fossil plants, respectively.

1.2.7 Seismology

All four proposed regions lie within the seismo-tectonic province known as the Gulf Coastal Plain (GCP). Since the GCP is a low seismicity area, nuclear power plant seismic design is governed by the minimum acceleration values permitted by the NRC, rather than by the actual historical earthquake events felt in the four regions. Accordingly, most of the discussion for the North Baton Rouge sites is applicable to all of the regions under consideration.

In determining the safe shutdown earthquake (SSE) or the operating basis earthquake (OBE) for the four regions under consideration, attention must be focused on both local and distant earthquakes. Both the Waterford and River Bend Nuclear Power Plants (which lie south and north of the Baton Rouge and Geismar regions, respectively) have the Donaldsonville, Louisiana, earthquake of 1930 as the controlling local seismic event with an epicentral intensity of VI MM (Modified Mercalli).^(5,6) Seismology for the Blue Hills Nuclear Power Plant is influenced by the Hemphill earthquakes of 1964.⁽⁷⁾ Like the Donaldsonville event, the intensities of the Hemphill earthquakes have been estimated to be as high as VI MM.

The New Madrid, Missouri, earthquakes of 1811-1812 were the largest historic earthquakes affecting nuclear plant siting in the Central United States. However, because the epicentral locations of these events were hundreds of miles north of the proposed site regions, the resulting ground motion at the Waterford and River Bend sites was no greater than the ground motion caused by the Donaldsonville earthquake. Even when the New Madrid earthquakes are hypothesized to recur at the southernmost boundary of the seismo-tectonic province in which the New Madrid events occurred, the attenuation with distance results in predicted ground motions at the four proposed regions no greater than that which would be caused by a postulated repeat of the Donaldsonville or Hemphill earthquakes directly beneath any of the four proposed regions. Thus, in terms of identifying the SSE for any of the four regions, the controlling earthquakes would be a local Intensity VI MM event.

The next step in the determination of the seismic design bases for nuclear power plants is to correlate MM intensities with horizontal ground accelerations. Thus, having determined that the onsite ground motion at any of the four regions can be characterized as Intensity VI MM for the SSE, the ground acceleration corresponding to this level of seismic motion must be estimated. Numerous correlations have been developed over the years between MM intensity and acceleration. Historically, it appears that the NRC has used the most conservative of the correlations postulated at any given time. The Gutenberg-Richter relationship was used extensively in early nuclear plant licensing.⁽⁸⁾ Since the early 1970's, utility applicants for nuclear plant permits have most often used the Neumann,⁽⁹⁾ Trifunac and Brady,⁽¹⁰⁾ or Coulter-Waldron-Devine⁽¹¹⁾ relationships, although the last appears to have fallen into some disfavor recently.^(3,4,12)

Using any of the above correlations, the SSE accelerations at any of the four sites would be 0.07g based on the aforementioned corresponding intensity. Since this value is lower than the currently mandated minimum value of 0.10g for the SSE, the acceleration of 0.10g is recommended for conceptual and feasibility purposes.

The OBE earthquakes governing the design of nuclear plants at the four regions would be controlled by the same "local" earthquakes; i.e., the Donaldsonville affecting the North Baton Rouge and Geismar regions and the Hemphill affecting the Lake Charles and Orange regions. In all cases, the intensity of ground motion observed at the four regions during the aforementioned earthquakes was less than the equivalent minimum required by the NRC for OBE design, as subsequently discussed. Thus, intensities observed at the four regions during the Donaldsonville or Hemphill events

are estimated to have been in the range III-IV MM. These intensities result in ground acceleration lower than the minimum value of 0.05g which is currently required by the NRC for OBE seismic design.

It should be pointed out that in other regions of the United States, the NRC appears to be mandating higher minimum values of OBE and SSE accelerations. This is being accomplished by assuming more conservative boundaries for seismo-tectonic provinces. This results in the governing "distant" earthquakes being artificially postulated to recur closer to the proposed sites. For example, in the Northeast United States the end result of this position by the NRC is that the current "unofficial" minimum value of SSE acceleration has been raised to 0.20g. It is emphasized that the minimum acceleration values which can be licensed for nuclear plants seem to be increasing. Values recommended for any of the four regions (i.e., 0.05g and 0.10g) are based on current seismo-tectonic boundaries for the New Madrid earthquakes of 1811-1812. The current southern limit of the seismo-tectonic province for the New Madrid earthquakes results in the postulation that the New Madrid events cannot be assumed to recur any closer to the four evaluated regions than Memphis, Tennessee. Very detailed "vibroseis" data across the Mississippi Embayment north and south of Memphis have been used to define geologic structure and thereby provide the geologic evidence for the southern limit of the New Madrid seismic zone. This evidence is considered to be definitive and it is unlikely that the New Madrid events could be postulated to recur any farther south than Memphis, Tennessee.

The consequences of increasing the design acceleration values are primarily in increased costs for pipe supports and seismic qualification of electrical and mechanical equipment.

For fossil power plants, the Southern or Uniform Building Codes provide recommendations for the seismic design. The seismic risk map contained in these building codes delineate the four proposed regions within Zone 1, which is the lowest permissible seismic design basis for continental United States. Typically for Zone 1, seismic design is not the governing criterion; other design parameters such as wind, thermal, or equipment loads result in higher stresses.

Matrix rating values of 20 and 10 for nuclear and fossil plants, respectively, were assigned to all the evaluated regions except Orange. For nuclear plant siting, Orange was downgraded to a matrix rating of 17 in recognition of the existing SSE acceleration value of 0.13g that was docketed for the Blue Hills Nuclear Plant.(7)

1.2.8 Meteorology

The climate of the site is generally described as humid subtropical. Prevailing southeasterly winds combined with the moisture supply and warm waters of the Gulf of Mexico provide mild but rather humid weather throughout most of the year. Air from the continental interior occasionally brings drier and usually cooler weather, but air of continental origin influences the region very little during the summer and partly during other seasons.

The summer climate is warm and humid. Daily mean and maximum temperatures average about 82 F and 92 F, respectively. Precipitation averages about 5 inches per month. Afternoon thundershowers, which account for much of the rainfall, occur about one day in three during the summer months.

The winter climate is pleasant, due to mild temperatures and only moderate precipitation. Daily mean and maximum temperatures average 54 F and 64 F, respectively; and freezing temperatures occur on an average of one night in four.

Cold air, accompanied by brisk winds, occasionally moves southward causing rapid temperature drops of considerable magnitude; however, prolonged cold spells are unusual. Winter precipitation, which averages nearly 5 inches per month, occurs partly from steady rains caused by tornadoes and partly from showers accompanying the arrival of cold air from the north. Snow or freezing rain is rare.

Spring comes early and is the season of most frequent tornado occurrence. Based on a study of tornado occurrences during the period 1955 through 1967, mean tornado frequency in a 1 degree (latitude-longitude) square was determined to be about 1.7 per year.⁽¹³⁾ The probability of a tornado striking a point on a given site is estimated at once every 855 years.

Tropical storm frequency is highest in early autumn. The most pleasant month is usually October, which has moderate temperatures and the least precipitation and cloudiness of any month. A matrix rating of 11 was assigned to both nuclear and fossil plants.

1.2.9 Ecology and Croplands

The site is located in an industrial area with no significant ecological features. There are no croplands in the site vicinity. The Mississippi River at that location does not have any fishing activity. A matrix rating of 10

was assigned to both nuclear and fossil plant considerations.

1.2.10 Air Quality (Fossil)

Louisiana state ambient air quality standards became effective January 30, 1972. The ambient air standards established for suspended particulates, sulfur oxides, and nitrogen oxides are essentially equivalent to existing national primary standards, referenced in Table A-1. A matrix rating of 16 was assigned to a fossil-fuel plant at this site.

TABLE A-1

A. LOUISIANA AMBIENT AIR QUALITY STANDARDS

<u>POLLUTANT</u>	<u>PERIOD</u>	<u>ug/m³</u>	<u>ppm</u>
Suspended Particulates	Annual Geometric Mean	75	-
	Maximum 24-hr Average*	260	-
Sulfur Dioxide	Annual Arithmetic Mean	80	0.03
	Maximum 24-hr Average*	365	0.14
Nitrogen Oxides	Annual Arithmetic Mean	100	0.05

B. NATIONAL AMBIENT AIR QUALITY STANDARDS

<u>POLLUTANT</u>	<u>AVERAGING TIME</u>	<u>PRIMARY STD.</u> <u>ug/m³</u>	<u>ppm</u>	<u>SECONDARY STD.</u> <u>ug/m³</u>	<u>ppm</u>
Particulate	Annual Geometric Mean	75	-	60	-
	24 hr*	260	-	150	-
Sulfur Oxides	Annual	80	0.03	60	0.03
	24 hr*	365	0.14	260	0.1
	3 hr*	-	-	1,300	0.5
Nitrogen Oxides	Annual	100	0.05	100	0.05

*Not to be exceeded more than once per year.

1.2.11 Radiological Considerations (Nuclear)

Although the North Baton Rouge site has an acceptable exclusion area boundary (EAB), the low population zone (LPZ) must be coincident with the EAB or it will far exceed the NRC guide of approximately 4,000 persons in the LPZ. This means, of course, that immediately surrounding the EAB, the population density is extremely high (far in excess of 500

persons per square mile). This site is least suitable for a nuclear plant. Consequently, it received a matrix rating of 5.

1.2.12 Demography (Nuclear)

The North Baton Rouge region is located about 3 miles from downtown Baton Rouge. The site is actually located within the city limits of Baton Rouge, which has a current population of about 209,000. The population within a 30-mile radius is approximately 487,600, reflecting a population density of 172 persons per square mile. The population within a 2-mile radius of the plant is greater than 40,000, which translates to a population density exceeding 3,000 persons per square mile. For this reason, a matrix rating of 0 was assigned to nuclear plants at this site. (Demography is not a licensing consideration in connection with fossil fuel plants.)

1.2.13 Noise Impact

It is expected that no significant noise will be generated by a nuclear power plant.

Significant noise impact is anticipated during the operation of a fossil plant due to noise generated by outside equipment and the proximity to the university and residential communities. Sound barriers and other antinoise features would add to the cost of facility construction. A matrix rating of 4 was assigned to nuclear and 5 to fossil plants.

1.2.14 Proximity to Hazardous Facilities (Nuclear)

North Baton Rouge Site A/B is located approximately 1,000 feet from a facility/activity with potentially hazardous materials. A matrix rating of 2 was assigned to nuclear plants.

1.3 SOCIOECONOMIC CONSIDERATIONS

1.3.1 Transportation

As stated earlier in Section 1.1.3, the site has access to rail, highway, and water as possible modes of transportation. Assuming the site can accept fuel by barge, the impact on the river corridor will be minimal. If fuel is received by train, the impact on the rail corridor will also be minimal. Transportation of wastes by barge or rail will have little effect on the systems, but it is likely that solid wastes will be removed from the site by highway and some adverse traffic conditions may result. The traffic pattern must be studied closely and shipments properly

scheduled to minimize the impact on the highway corridors. A matrix rating of 5 was assigned to nuclear plants, 15 to fossil plants.

1.3.2 Community Impact

The North Baton Rouge site is located within the political boundaries of Baton Rouge. It is probable that there will be some undesirable impacts on the surrounding community due to the movement of men, material, and machines. Impact to community infrastructures is expected to be minimal, even when assuming that the total work force resides in the Baton Rouge area. The estimated average construction work force for a nuclear plant is 1,200, slightly less for a fossil plant. Therefore, the total population addition (construction workers plus their families) would be approximately 3,200 persons, a 1.5 percent increase over several years. This is substantially less than the average annual population growth of the Baton Rouge area. Matrix ratings of 6 and 8 for nuclear and fossil plants were assigned, respectively.

1.3.3 Archaeological and Historical Impact

There are no known archaeological or historical areas within the site vicinity and no adverse effect is anticipated. Therefore, a matrix rating of 5 was assigned each plant.

1.3.4 Visual Impact

The candidate site is on the fringe of an industrial complex and acts as a buffer zone between the industrial area and the campus of Southern University. A low profile, such as a nuclear plant without cooling towers, would have negligible aesthetic impact; however, a fossil plant with its prominent stack will have an effect, since even a low-profile stack and boiler will be visible over a considerable distance. Of all the candidate sites, this site would have the greatest visual impact on the area. Matrix ratings of 5 and 4 were assigned to nuclear and fossil plants, respectively.

1.3.5 Transmission/Steam Line Impact

All sites in all regions were given a matrix rating of 5 since ecology and community impact were assessed to be the same.

2 LAKE CHARLES - SITE A

2.1 TECHNICAL/ENGINEERING CONSIDERATIONS

2.1.1 Site Preparation

Subsurface conditions in the Lake Charles region are extremely heterogeneous. Without specific information at the proposed sites, it is imprudent to suggest probable excavation depths or pile lengths and capacities for nuclear or fossil plants, respectively. For example, design loads for pile foundations in the Lake Charles region vary from 20 tons at a length of 56 feet to 50 tons at 50 to 85 feet, to 75 tons at 75 feet.⁽³⁾ On a qualitative basis, it appears that depths to firm bearing strata are greater in the Lake Charles region compared to the Orange region.

Because of relatively flat terrain adjacent to the Calcasieu River, flood protection will probably require construction of impervious dikes around the proposed Sites A and B rated 7 on the matrices. Site C is far enough removed from the flood potential immediately adjacent to the Calcasieu River to be given a rating of 10 for both plants.

2.1.2 Proximity to Load Demand

The steam customers in the Lake Charles region are widely dispersed. A preliminary calculation of the installed cost of the steam distribution system was made for Sites A and B. The distance from Site A to the steam users varies from 5,000 to 15,000 feet. Site A was the better of the two and was rated 20 for both plants.

2.1.3 Water Availability

The Calcasieu River and its tributaries are the principal sources of surface waters in the area. The average flow of the Calcasieu River is 2,470 cfs, with a minimum measured daily flow of 136 cfs and a maximum daily floodflow of 182,000 cfs. Since the power plant will replace the process needs of consumers by supplying steam, it is expected not to have a net effect on the total consumption of water for the industrial complex. The maximum plant water requirement of 30 cfs would equal about 1.2 percent of the average river flow and 22 percent of the minimum river flow. Due to lower volumetric flow of the Calcasieu River as compared to the Mississippi River, a matrix rating of 10 was assigned both plants.

2.1.4 Highway, Rail, and Water Access

The region is served by three railroad companies, one interstate highway, and one waterway. The Kansas City and Southern, the Missouri Pacific, and the Southern Pacific and Texas Railway companies serve the city of Lake Charles and vicinity. Interstate 10 connects the city of Lake Charles with points east and west, while U.S. Highways 171 and 165 link this region with areas to the north. These are supplemented by Interstate 210 and numerous state and parish roads located throughout the Lake Charles region. The Gulf Intracoastal Waterway, crossing the southern portion of the Lake Charles region, connects Sabine Lake at the Texas-Louisiana border with New Orleans and the Mississippi River. Since the site is located approximately 10,000 feet from the ship channel (river), economic penalties would be incurred if barge fuel unloading was installed. The construction costs for a new channel to serve the site would be expensive. An additional unloading site on the channel would be required with overland conveyers to the site, which again would result in relatively high costs. A matrix rating of 5 was assigned to nuclear and 20 to fossil plants.

2.1.5 Foundations

Because of the flood potential referred to in the section on Site Preparation, Sites A and B were rated 8 and Site C 12 for nuclear plants; fossil-fuel plants were rated 7 at Sites A and B, and 8 at Site C.

2.1.6 Water Supply Systems

The construction requirements for water supply systems, such as makeup and service water systems, do not pose any unusual problems. If placed on Bayou d'Inde, the water intake structure may provide water of better quality than the Calcasieu Ship Channel, which has high dissolved solids content; however, the unknown flows of Bayou d'Inde must be evaluated. The distance to either water source is approximately 10,000 feet. A matrix rating of 6 was assigned to both nuclear and fossil considerations.

2.1.7 Land Costs

The land costs at Lake Charles are slightly lower than the North Baton Rouge site, but still quite high because of its proximity to an industrial complex and developed areas. The proximity of this site to the railroad, the interstate highway, and Maplewood, and its higher elevation would be conducive to light manufacturing with resulting high land costs. A matrix rating of 3 was assigned for nuclear and fossil considerations.

2.1.8 Steam Supply/Demand Match

The steam demand in the Lake Charles region is similar to North Baton Rouge. All the sites were rated 10 for nuclear and fossil plants.

2.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

2.2.1 Wastewater Impact

Wastewaters from the power plant will not have an adverse effect on water quality. Any water discharged to the river will be fully treated so that requirements of all regulatory agencies will be met. A National Pollutant Discharge Elimination Statement (NPDES) will be filed and limits required for the Steam Electric Power Generating Point Source Category will be met.⁽⁴⁾ Every effort, including complete recycle, will be considered to close the wastewater cycle within economic limits. Matrix ratings of 3 and 6 were assigned for nuclear and fossil plants, respectively.

2.2.2 Cooling Water Impact (Nuclear)

The normal water flow through the Calcasieu Ship Channel should be adequate for emergency cooling; however, reservoirs or ponds may be required to ensure an adequate supply during dry periods or under certain tidal conditions. The peak emergency core cooling load is estimated at 270 million Btu/hr. On the basis of evaporative cooling, a makeup flow of approximately 40 cfs is required. This flow represents about 29 percent of the minimum measured daily flow and 16 percent of the average flow. A matrix rating of 3 was assigned.

2.2.3 Land Use

Since the site is located near the industrial users, has good transportation corridor access and relatively high elevation, and is close to residential Maplewood, it may be suitable for industrial development. Industrial use would not conflict with current zoning (industrial-commercial) or present land use. A matrix rating of 8 was assigned to both nuclear and fossil plants.

2.2.4 Land Requirements

Site A, the smallest of the three sites at Lake Charles, contains approximately 400 acres sufficient for either a fossil or a nuclear plant. Consequently, matrix ratings of 22 and 20 were assigned for fossil and nuclear plant siting, respectively.

2.2.5 Geology

The Lake Charles region is geologically dominated by the Lockport salt dome with its associated oil and gas fields.⁽⁷⁾ The two southern sites in the Lake Charles region are in the immediate vicinity of the Lockport dome; the third site is farther removed but, nonetheless, influenced by it.

The Lockport salt dome is seated deeper than those in the Geismar area, and ground subsidence, due to oil and gas withdrawal, is not regarded as a significant problem in contrast to the Geismar and North Baton Rouge regions.

The Tepehate-Baton Rouge fault zone is located about 10 miles north of Lake Charles. The Lake Arthur fault zone passes approximately 5 miles south of Lake Charles, and the Iowa fault zone strikes east-northwest across the Lockport salt dome. The proximity of these fault zones to the proposed Lake Charles sites may require considerable onsite and offsite geologic investigations for nuclear plant siting.

The generalized soil profiles at the proposed sites consist of interbedded silty sands, sandy clayey silts, and silty clays.⁽³⁾ Depths to firm bearing strata vary considerably throughout the Lake Charles area. Accordingly, pile capacities are highly site dependent, as are the probable depths of excavation for nuclear plant siting. Without detailed subsurface information at the specific proposed sites, pile capacities and lengths of piles cannot be estimated realistically. The depositional environment in the Lake Charles region has resulted in extreme variability in soil conditions.

Near-surface groundwater in the Lake Charles region contains dissolved methane gas which is generated from organic debris within the freshwater aquifers or from oil and gas sands underlying the aquifers.⁽¹⁾ This could present considerable safety concerns if dewatering is required for construction. In addition, encroachment of salt water into freshwater aquifers is a concern in this area. Again, any construction dewatering, if required, might result in environmental impacts. Matrix ratings of 15 and 14 were assigned to nuclear and fossil plants, respectively, for Sites A and B.

2.2.6 Hydrology

Lake Charles region has no record of severe flooding and, hence, it is not anticipated that more than minimal flood protection is required. Matrix ratings of 20 and 15 were assigned for nuclear and fossil plants, respectively.

2.2.7 Seismology

Refer to this heading under the North Baton Rouge description, Section 1.2.7.

2.2.8 Meteorology

The climate of the site is essentially the same as the North Baton Rouge site described in Section 1.2.7. A matrix rating of 9 was assigned to both nuclear and fossil plants.

2.2.9 Ecology and Croplands

The site and its surroundings are largely industrial and residential with an absence of croplands. There are no known wildlife preserves or endangered species in the area. Thus, impacts would be minimal. A matrix rating of 10 was assigned to both nuclear and fossil plants.

2.2.10 Air Quality (Fossil)

Same as North Baton Rouge (Section 1.2.10).

2.2.11 Radiological Considerations (Nuclear)

Having a 2.0-mile LPZ, Lake Charles Site A is not within the LPZ guidelines of 3.0 miles. Furthermore, the population center boundary distance of 2.8 miles is barely adequate to meet the 1 1/3 LPZ distance requirement. A matrix rating of 10 was assigned.

2.2.12 Demography (Nuclear)

Lake Charles Site A, located in the southwest corner of Louisiana, is in an area of gently rolling prairie and marshland. The population in 1970 was 137,779. Today (1977) there are about 149,000 persons, and it is expected that approximately 206,000 persons will be living in this area by 2020. Calcasieu Parish, in which the proposed site is located, had a 1976 population of 150,520 and is growing at about 0.98 percent per year. There are approximately 257,000 persons within a 30-mile radius of the site, reflecting a population density of 91 persons per square mile. Population projections indicate a population of about 365,000 by 2020, which reflects a population density of 129 persons per square mile.

The city of Lake Charles, located about 5 miles east of the candidate site, has a population of approximately 84,000. Other population concentrations include: Hollywood, located 1.5 miles west, with a population of 2,500; Sulphur, located 3.5 miles northwest, with a population of 14,600; and Westlake, located 3 miles northeast, with a population of

4,400. Therefore, the total population in a 5-mile radius of the site is approximately 105,000, a population density of 1,340 persons per square mile. A matrix rating of 19 was assigned.

2.2.13 Noise Impact

Because of the proximity of residential sections Maplewood and Hollywood (approximately 2 miles distant), noise is a problem with a fossil plant and antinoise design and construction cost factors in the overall cost of the station. Therefore, a matrix rating of 5 was assigned for fossil and 4 for nuclear plants.

2.2.14 Proximity to Hazardous Facilities (Nuclear)

Lake Charles Site A is located approximately 6,000 feet from a facility that contains potentially hazardous materials. A matrix rating of 15 was assigned.

2.3 SOCIOECONOMIC CONSIDERATIONS

2.3.1 Transportation

The site has access to rail, highway, and water transportation. The transportation of fuel to the plant by rail and of wastes from the plant by rail or highway would not have adverse effects on transportation systems. Nuclear and fossil plants received full-value matrix ratings of 5 and 15, respectively.

2.3.2 Community Impact

Lake Charles Site A is located approximately 5 miles from the City of Lake Charles and includes a population of about 84,000. Also within the 5-mile radius are three towns with a total population of 22,000. The movement of men, material, and machines should have little impact on surrounding communities. As indicated in Section 1.3.2, the estimated construction work force plus families would add a maximum of about 3,200 persons to surrounding communities. This represents a 3 percent population increase, which should have little impact on the infrastructure of these communities. Matrix ratings of 8 and 9 were assigned to nuclear and fossil plants, respectively.

2.3.3 Archaeological And Historical Impact

There are no known archaeological sites in the site vicinity. There is a significant historical and recreation area in the Calcasieu Parish about 8 miles distant: the Imperial Calcasieu Historical Museum and Sam Houston State

Park. However, no adverse impact is expected on these installations if a power plant were built. We assigned a matrix rating of 5 to both plants.

2.3.4 Visual Impact

A power plant on this site may create visual impact problems affecting nearby residential communities. The proposed power plant presents a significant profile because it will stand alone on the site which is located near Interstate 210. A matrix rating of 8 was applied to a fossil plant and 5 to a nuclear plant.

2.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

3 LAKE CHARLES - SITE B

3.1 TECHNICAL/ENGINEERING CONSIDERATIONS

3.1.1 Site Preparation

Refer to Site Preparation, Lake Charles Site A, Section 2.1.1.

3.1.2 Proximity to Load Demand

The distances from Site B to the steam users vary from 6,000 to 21,000 feet. Based on the analysis described in 2.1.2, Site B was rated 15 for Proximity to Load Demand.

3.1.3 Water Availability

The availability of water is essentially the same as Lake Charles Site A.

3.1.4 Highway, Rail, and Water Access

Highway and rail access is essentially the same as for Lake Charles Site A, and favorable access to the Calcasieu Ship Channel should allow barge transportation of coal for a fossil plant. Special dock unloading facilities will be required due to the narrow channel. A matrix rating of 5 was assigned for nuclear and 20 for fossil plants.

3.1.5 Foundations

Refer to Foundations, Lake Charles Site A, Section 2.1.5.

3.1.6 Water Supply Systems

The water supply systems would be the same as Lake Charles Site A.

3.1.7 Land Costs

Land costs are expected to be high and similar to Lake Charles Site A. Direct access to the ship channel increases its value as does its proximity to the industrial complex. Offsetting these advantages is the lower elevation compared to Site A. A matrix rating of 3 was assigned for nuclear and fossil plant considerations.

3.1.8 Steam Supply/Demand Match

See Lake Charles Site A, Section 2.1.8.

3.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

3.2.1 Wastewater Impact

Same as Lake Charles Site A. See Section 2.2.1.

3.2.2 Cooling Water Impact (Nuclear)

Same as Lake Charles Site A. See Section 2.2.2.

3.2.3 Land Use

The site, zoned industrial-commercial, is located adjacent to an industrial complex. A process plant appears to be the main competition for this site. Serious conflicts regarding land use are not expected. Matrix ratings are the same as for Lake Charles Site A.

3.2.4 Land Requirements

Site B contains approximately 600 acres and sufficient area to support either plant. Consequently, matrix ratings of 25 and 20 were assigned for fossil and nuclear plant siting, respectively.

3.2.5 Geology

Refer to Lake Charles Site A, Section 2.2.5.

3.2.6 Hydrology

Similar to Lake Charles Site A, except the elevation is lower (see Section 2.2.6). Some minor flood protection may be required. A matrix rating of 16 was assigned to the nuclear plant; a rating of 13 was assigned to the fossil plant.

3.2.7 Seismology

Refer to North Baton Rouge Sites A/B, Section 1.2.7.

3.2.8 Meteorology

Similar to Lake Charles Site A except for a favorable location of the plant relative to prevailing winds (Section 2.2.8). A matrix rating of 11 was assigned to both nuclear and fossil sites.

3.2.9 Ecology and Croplands

Same as Lake Charles Site A. See Section 2.2.9.

3.2.10 Air Quality (Fossil)

Same as North Baton Rouge, Section 1.2.10.

3.2.11 Radiological Considerations (Nuclear)

Lake Charles Site B distances are slightly less to the LPZ outer boundary and population center boundary (1.8 miles and 2.5 miles, respectively) than Lake Charles Site A. It is not a favorable nuclear site. Consistent with the Lake Charles Site A, a matrix rating of 10 was given.

3.2.12 Demography (Nuclear)

Refer to Demography, Lake Charles Site A, Section 2.2.1.2.

The city of Lake Charles is located about 5 miles east of the candidate site and has a population of approximately 84,100. Other population concentrations include: Hollywood, located 2 miles north, with a population of 2,500; Sulphur, located 3.5 miles northwest, with a population of 14,600; and Westlake, located 4.5 miles northeast, with a population of 4,400. A matrix rating of 14 was assigned.

3.2.13 Noise Impact

The potential impact of noise is similar to Lake Charles Site A, except that this site is further from the residential communities of Hollywood and Maplewood; the distance is approximately 2 miles. Noise proofing would not be as extensive for this site. A matrix rating of 8 was assigned for fossil and 4 for nuclear plants.

3.2.14 Proximity to Hazardous Facilities (Nuclear)

Lake Charles Site B is located approximately 5,300 feet from a facility that contains potentially hazardous materials. A matrix rating of 15 was assigned.

3.3 SOCIOECONOMIC CONSIDERATIONS

3.3.1 Transportation

Same as Lake Charles Site A, Section 2.3.1.

3.3.2 Community Impact

Same as Lake Charles Site A, Section 2.3.2.

3.3.3 Archaeological and Historical Impact

Same as Lake Charles Site A, Section 2.3.3.

3.3.4 Visual Impact

Lake Charles Site B's proximity to the industrial complex and its remoteness from residential communities and highways should not impact significantly. Matrix ratings of 9 and 5 have been assigned to fossil and nuclear plants, respectively.

3.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

4 LAKE CHARLES - SITE C

4.1 TECHNICAL/ENGINEERING CONSIDERATIONS

4.1.1 Site Preparation

Refer to Site Preparation, Lake Charles Site A, Section 2.1.1.

4.1.2 Proximity to Load Demand

A matrix rating of 0 was assigned to Site C because it requires steam distribution pipes longer than 5 miles.

4.1.3 Water Availability

The Houston River appears to be the best source of water for this site. The Sabine River diversion channel, which is presently under construction, could provide an alternate source but is limited by its design capacity to an ultimate flow capability of 446 cfs. The Houston River, while with water of better quality than the Calcasieu Ship Channel, has an average flow availability of less than 2,000 cfs; thus, this site would be less desirable than the other two Lake Charles sites from a water availability standpoint. Therefore, a matrix rating of 7 was assigned for nuclear and fossil plants.

4.1.4 Highway, Rail, and Water Access

Kansas City Southern Railroad runs near the site and provides an excellent corridor for train delivery of coal. Barge unloading is not economically feasible for this site due to excessive distance to the Calcasieu Ship Channel. Highway access is also poor, since the site is served by secondary roads. A matrix rating of 15 for fossil and 5 for nuclear plants has been assigned.

4.1.5 Foundations

Refer to Lake Charles Site A, Section 2.1.5.

4.1.6 Water Supply Systems

Construction requirements for water supply systems are more expensive for Lake Charles Site C due to its greater distance (7,000 ft) from the Houston River. Treatment costs, however, are less, since the water is of better quality. A matrix rating of 7 was assigned for both nuclear and fossil considerations.

4.1.7 Land Costs

The land costs for this site are expected to be low since it is in a remote location. There is no present use of land adjacent to the site other than Gulf States Utilities Company's Nelson Station located nearby. The higher elevation tends to offset the remoteness of the site. A matrix rating of 5 was assigned for nuclear and fossil plants.

4.1.8 Steam Supply/Demand Match

Refer to Steam Supply/Demand Match, Lake Charles Site A, Section 2.1.8.

4.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

4.2.1 Wastewater Impact

Same as Lake Charles Site A. See Section 2.2.1.

4.2.2 Cooling Water Impact (Nuclear)

Same as Lake Charles Site A, Section 2.2.2.

4.2.3 Land Use

This site, zoned industrial-commercial, is remotely located from industrial and residential communities and is close to an existing electric generating plant; therefore, no conflicts are expected from land use. Matrix ratings of 10 were assigned.

4.2.4 Land Requirements

This landlocked site contains approximately 700 acres, sufficient to support either a fossil or a nuclear plant. Consequently, matrix ratings of 25 and 20 were assigned for fossil and nuclear plant siting, respectively.

4.2.5 Geology

Refer to Lake Charles Site A, Section 2.2.5. Matrix ratings of 17 and 15 were assigned to nuclear and fossil plants, respectively.

4.2.6 Hydrology

Similar to Site A, Site C has a higher elevation than Lake Charles Site B and is desirable from a hydrological standpoint. Therefore, matrix ratings of 20 and 15 were assigned for nuclear and fossil plants, respectively.

4.2.7 Seismology

Refer to North Baton Rouge, Section 1.2.7.

4.2.8 Meteorology

Same as Lake Charles Site A. See Section 2.2.8.

4.2.9 Ecology and Croplands

Same as Lake Charles Site A. See Section 2.2.9.

4.2.10 Air Quality (Fossil)

Same as North Baton Rouge, Section 1.2.10.

4.2.11 Radiological Considerations (Nuclear)

Lake Charles Site C meets the LPZ and population center boundary distance guidelines with a distance of 3.0 and 4.0 miles, respectively. It is therefore adequate for a nuclear site. Because these distances are adequate, but do not exceed guidelines by a significant margin, a matrix rating of 20 was assigned.

4.2.12 Demography (Nuclear)

Refer to Demography, Lake Charles Site A, Section 2.2.12.

The city of Lake Charles, located 5 miles east of the candidate site, has a population of approximately 84,000. Other population concentrations include: Hollywood, located 3.5 miles southwest, with a population of 2,500; Sulphur, located 5 miles west northwest, with a population of 14,600; and Westlake, located 2.2 miles northeast, with a population of 4,400. A matrix rating of 14 was assigned.

4.2.13 Noise Impact

Similar to Lake Charles Site B. The nearest residential community of Westlake is approximately 2 miles distant. Matrix ratings are 4 for nuclear and 8 for fossil plants, as in Site B.

4.2.14 Proximity to Hazardous Facilities (Nuclear)

Lake Charles Site C is located approximately 12,000 feet from a facility that contains potentially hazardous materials. A matrix rating of 20 was assigned.

4.3 SOCIOECONOMIC CONSIDERATIONS

4.3.1 Transportation

The site has access to rail and secondary highway systems. The transportation of fuel to the plant and of wastes from the plant by rail would have little impact on rail transportation corridors. The transportation of ash wastes from the plant by highway may present problems depending upon the location of the disposal site and onsite waste disposal must be seriously considered. Accordingly, a matrix rating of 5 has been assigned to nuclear plants and 12 to fossil plants.

4.3.2 Community Impact

Same as Lake Charles A, Section 2.3.2.

4.3.3 Archaeological and Historical Impact

Same as the other Lake Charles sites.

4.3.4 Visual Impact

Visual impact is not expected because of the remote location of this site. The full-value matrix ratings of 5 and 10 were assigned to both the nuclear and fossil plants, respectively.

4.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

5 ORANGE COUNTY - SITE A

5.1 TECHNICAL/ENGINEERING CONSIDERATIONS

5.1.1 Site Preparation

As previously indicated, soil stratification appears to be somewhat more uniform in the Orange region than in the Lake Charles area.⁽³⁾ Nearby chemical plants are typically founded on piles ranging in length from 50 to 70 feet, with pile design load capacities from 40 to 60 tons. Piles are usually founded in a medium-dense fine sand at these depths. Immediately overlying this sandy bearing stratum is a silty clay ranging in consistency from firm to very stiff. Depending on the magnitude of foundation-bearing pressures, large mat foundations might conceivably be founded on this higher silty clay layer, depending on design criteria for gross and differential building settlements. The silty clay stratum is not a problem in terms of liquefaction. Thus, depth of excavation for a nuclear plant, or length of piles for a fossil plant, appear to be less at Orange than at Lake Charles.

Salt water encroachment in the groundwater aquifers is a concern in the Orange area. Therefore, any construction dewatering that may be required will necessitate a thorough evaluation to assess its impact on existing groundwater wells in the region.

The proposed sites are adjacent to swampy terrain bordering the Sabine River. Protection in the form of impervious earth dikes appear necessary to preclude flooding at the proposed sites. Considering these factors, matrix values of 7 were assigned to Sites A and B for both types of plants.

5.1.2 Proximity to Load Demand

The steam customers in the Orange region are clustered in a reasonably small area. The distance from Site A to the users varies from 5,000 to 10,000 feet. By observation, Site A was rated 20 for Proximity to Load Demand.

5.1.3 Water Availability

The Sabine River is the principal source of surface water. The average flow at BonWier, Texas, several miles upstream of the site, is 6,528 cfs with a minimum measured daily flow of 134 cfs and a maximum daily flow of 115,000 cfs. A power plant would not increase the total consumption of water, since steam supplied by the plant replaces existing customer supplies. In this way, the plant does not create new demands but reduces overall consumption through more

flexible and efficient operation. Maximum plant water use equals 0.46 percent of the average river flow and 22 percent of the minimum flow. A matrix rating of 15 was assigned for nuclear and fossil plants.

5.1.4 Highway, Rail, and Water Access

This region is served by two major railway lines, the Missouri Pacific Railroad and the Southern Pacific Railroad. These lines provide rail connections to the southwestern, far western, and central states. The Kansas City Southern Railroad is located 14 miles north of Orange and provides excellent interchange with the Missouri Pacific Railroad. The Sabine River and Northern Railroad, a short line of 30 miles, connects with four major railroads including the Missouri Pacific, Southern Pacific, Kansas City Southern, and Santa Fe. Interstate 10 is a major highway connecting with points to the east and west. The Gulf Intracoastal Waterway intercepts the Sabine and Neches Rivers south of Orange and links Orange to area water transportation. Orange is served by a deep channel link to the Gulf via the Sabine River and the Intracoastal Waterway. Barge unloading of fuel does not appear economical. Matrix ratings of 5 and 20 were assigned to nuclear and fossil plants, respectively.

5.1.5 Foundations

See the section Site Preparation, above. In accordance with the conditions indicated, values of 11 were assigned both sites for each type of plant.

5.1.6 Water Supply Systems

The construction requirements of water supply systems, such as makeup and service water, should not pose unusual problems. An intake structure placed on a branch of Cow Bayou may provide water of better quality than the Sabine River. However, because of the unknown flows of Cow Bayou, the site must also be evaluated based on the use of the Sabine River as the water source. Matrix ratings of 8 were assigned to both nuclear and fossil plants.

5.1.7 Land Costs

Land costs are expected to be high because of the proximate location to the industrial complex and the Sabine River. Offsetting the advantages is the relatively low elevation of the site. Therefore, a matrix rating of 3 was assigned to both nuclear and fossil.

5.1.8 Steam Supply/Demand Match

The steam demand in the Orange region can be supplied from an intermediate-size LWR, and both sites in this region were given the maximum matrix rating of 15 for Steam Supply/Demand Match for nuclear plants; both sites were rated 10 in the fossil consideration.

5.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

5.2.1 Wastewater Impact

The wastewaters from the power plant will have no adverse effect on water quality since all applicable restrictions and regulations will be met. Matrix ratings of 4 for nuclear and 9 for fossil were assigned.

5.2.2 Cooling Water Impact (Nuclear)

The normal flow through the Sabine River should be adequate for emergency cooling; however, reservoirs or ponds may be required to ensure adequate cooling water supply during dry periods or under varying tidal conditions. The peak emergency core cooling load is estimated at 270 million Btu/hr. On the basis of evaporative cooling, a makeup flow of approximately 40 cfs is required. This flow represents about 30 percent of the minimum measured daily flow and 0.6 percent of the average flow. A matrix rating of 4 was assigned.

5.2.3 Land Use

Since the site is zoned industrial and located near the steam users and some distance from any residential community, it is unlikely to have commercial or residential value. The relatively low elevation of the site and its remoteness make it likely to be used for industrial purposes. A matrix rating of 10 was assigned for both nuclear and fossil plants.

5.2.4 Land Requirements

Site A is smaller than Orange Site B, totaling approximately 300 acres. This acreage is adequate to support either a fossil or a nuclear plant. Consequently, matrix ratings of 20 and 15 were assigned for nuclear and fossil sites, respectively.

5.2.5 Geology

The Orange salt dome is located several miles north of the proposed site.⁽⁷⁾ The oil field adjacent to the site does not appear to be associated with the Orange salt domes, but is associated with some minor faulting mapped in the region. This faulting may be an extension for the Iowa fault zone described in the Geology section for the Lake Charles region.

The nearby faults may require considerable offsite and onsite geologic investigations for nuclear plant siting.

Subsidence is not a significant problem in the proposed region.

Subsurface stratigraphy consists of interbedded fine sands and silty clays.⁽³⁾ Individual soil layers appear to be appreciably thicker than at Lake Charles; i.e., deposits are less heterogeneous. Accordingly, variations in depth to firm bearing strata and resulting lengths of piles are less than in the Lake Charles region.

The geological considerations lead to the assignment of 15 and 12 to nuclear and fossil plant sites, respectively.

5.2.6 Hydrology

The Orange site is a part of the flat Texas Coastal Plain that extends along the Gulf Coast. It is located on the Sabine River about 15 miles northeast of Port Arthur. The elevation of the site area ranges from 12 to 20 feet above mean sea level. The average discharge rate of the Sabine River in the Orange site area is 6,000 to 8,000 cfs. This flow is partially regulated by the Toledo Bend Reservoir (completed in 1966) located 90 miles upstream. The peak discharge within the last 90 years, which occurred on May 22, 1953, was 121,000 cfs. This discharge resulted in a water level of approximately 29 feet above mean sea level at Ruiloff, Texas. Since the Orange site is located on a wider floodplain about 18 miles downstream, the area to disperse the floodwaters is larger. Therefore, the flood elevation would be lower. It is estimated that a 20-foot flood level at Ruiloff would translate to about a 15-foot flood level above mean sea level at the Orange site area. This estimate is subject to further hydrologic investigation. Therefore, it appears that the degree of plant flood protection or hardening would be minimal. Maximum matrix ratings of 20 and 15 were assigned to nuclear and fossil plants, respectively.

5.2.7 Seismology

Refer to Section 1.2.7 under the North Baton Rouge description. As indicated therein, the precedent licensing of the Blue Hills Nuclear Plant with 0.13g acceleration has caused a slight downgrading of the Orange sites to matrix values of 17.

5.2.8 Meteorology

The climate is humid subtropical and essentially the same as the North Baton Rouge site. Temperatures below freezing occur on the average of 11 days per year. The precipitation and mean temperature are shown on Table A-2. Maximum matrix ratings of 15 were assigned to both nuclear and fossil plants.

TABLE A-2

ANNUAL MEAN PRECIPITATION AND TEMPERATURE
ORANGE REGION

<u>Year</u>	<u>Annual Mean Precipitation (In.)</u>	<u>Annual Mean Temperature (Degrees)</u>
1969	47.31	66.9
1970	51.63	69.4
1971	45.42	69.2
1972	58.96	68.9
1973	78.90	67.4
1974	63.24	68.6
1975	86.15	68.2

5.2.9 Ecology and Croplands

As mentioned, Orange County is part of the flat Texas Coastal Plain. The southern portion of the county is prairie land, whereas the northern portion is timberland. There are no known endangered species or croplands in the vicinity of the site and there should be little or no impact on the ecology. A matrix rating of 10 was assigned to both nuclear and fossil plants.

5.2.10 Air Quality (Fossil)

Same as the North Baton Rouge site; see Section 1.2.10.

5.2.11 Radiological Considerations (Nuclear)

Orange Site A's LPZ distance is 1.7 miles. The population center boundary distance is 2.2 miles. This location is not favorable for a nuclear site. Consequently, it was assigned a matrix rating of 10.

5.2.12 Demography (Nuclear)

As mentioned, Orange Site A is located about 15 miles northeast of Port Arthur. The population of the area known as Greater Orange is about 48,000. The population of Orange County is about 88,000 and is expected to reach 199,000 by 2020. The city of Orange is the closest population center, located 3 miles north, with a current population of about 29,000. Currently, there are approximately 760,000 persons living within a 30-mile radius of the candidate region. This reflects a population density of 269 persons per square mile and a matrix rating of 20.

5.2.13 Noise Impact

The nearest residential community, West Orange, is almost 2 miles away. Serious impact problems are not anticipated; however, some noise prevention may be required in the design of a fossil plant. We have appointed a matrix rating of 10 for fossil and 5 for nuclear plants.

5.2.14 Proximity to Hazardous Facilities (Nuclear)

Orange Site A is located approximately 4,000 feet from a facility that contains potentially hazardous materials. A matrix rating of 12 was assigned.

5.3 SOCIOECONOMIC CONDITIONS

5.3.1 Transportation

The site has access to rail and highway systems. The transportation of fuel to the plant would have no major adverse effects on the transportation corridors. Waste transportation by highway may present problems depending upon the location of the disposal sites. The nuclear matrix rating is 5, the fossil rating 13.

5.3.2 Community Impact

Orange Site A is located about 15 miles from Port Arthur, which has a population of over 40,000, and 4 miles from the city of Orange, described in Section 5.2.12. As indicated in Section 1.3.2, the addition of construction workers plus their families (about 3,200 persons) should have little

impact on the infrastructures of this area. Also, the relatively longer distance to the surrounding communities indicates that the movement of men, material, and machines during plant construction should not have major impact on the communities. A matrix rating of 10 was assigned to both nuclear and fossil plants.

5.3.3 Archaeological and Historical Impact

There are no known archaeological or historical sites within the vicinity of the site. Therefore, matrix ratings of 5 were assigned.

5.3.4 Visual Impact

The location of the site poses no visual problems, since the area is located in an existing industrial community. Matrix ratings of 5 and 9 have been assigned to nuclear and fossil plants, respectively.

5.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

6 ORANGE COUNTY - SITE B

6.1 TECHNICAL/ENGINEERING CONSIDERATIONS

6.1.1 Site Preparation

Refer to Site Preparation, Orange Site A, Section 5.1.1.

6.1.2 Proximity to Load Demand

All steam users are located within a distance of 8,000 feet from Site B, which was given the maximum rating of 25.

6.1.3 Water Availability

This site is landlocked and would require piping water from the Sabine River or Cow Bayou, thus incurring greater cost than Site A. A matrix rating of 15 was assigned for both nuclear and fossil plants.

6.1.4 Highway, Rail, and Water Access

Site B is similar to Orange Site A except there is no access to water transportation. Matrix rating is 5 for a nuclear plant, 20 for a fossil plant.

6.1.5 Foundations

Refer to Orange Site A, Section 5.1.5.

6.1.6 Water Supply Systems

This site is similar to Orange Site A; however, supply lines from the Sabine River or from Cow Bayou would be longer (approximately 12,000 feet) and more expensive. The assigned matrix rating is 7 for both plants.

6.1.7 Land Costs

Land costs of Site B are similar to Orange Site A. While land elevation is higher than Site A, it lacks water transportation. In accordance with this, costs can be expected to be lower than Site A. A matrix rating of 5 was assigned to both nuclear and fossil plants.

6.1.8 Steam Supply/Demand Match

Refer to Steam Supply/Demand Match, Orange Site A, Section 5.1.8.

6.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

6.2.1 Wastewater Impact

Same as Orange Site A, Section 5.2.1.

6.2.2 Cooling Water Impact (Nuclear)

Same as Orange Site A, Section 5.2.2.

6.2.3 Land Use

Same as Orange Site A, Section 5.2.3.

6.2.4 Land Requirements

Site B contains approximately 580 acres and is adequate to support either a nuclear or fossil plant. Matrix ratings of 25 and 20 were assigned for fossil and nuclear plants, respectively.

6.2.5 Geology

Same as Orange Site A, Section 5.2.5.

6.2.6 Hydrology

Same as Orange Site A, Section 5.2.6.

6.2.7 Seismology

See North Baton Rouge, Section 1.2.7, and Orange Site A, Section 5.2.7.

6.2.8 Meteorology

Same as Section 5.2.8.

6.2.9 Ecology and Croplands

Same as Section 5.2.9.

6.2.10 Air Quality (Fossil)

Same as the North Baton Rouge site; see Section 1.2.10.

6.2.11 Radiological Considerations (Nuclear)

Orange Site B has an LPZ distance of 1.5 miles and a population center boundary distance of 3.4 miles. This is not favorable for a nuclear site; consistent with Orange Site A, a matrix rating of 10 was assigned.

6.2.12 Demography (Nuclear)

Refer to Demography, Orange Site A, Section 5.2.12. The city of Orange is the closest population center to Orange Site B, located 3.4 miles northeast. There are about 760,000 persons living within a 30-mile radius of the candidate site. This reflects a population density of 269 persons per square mile and a matrix rating of 20.

6.2.13 Noise Impact

Noise impact at this site is the same as Orange Site A, except that the distance to residential West Orange is slightly less. The matrix ratings are 5 for nuclear and 10 for fossil plants.

6.2.14 Proximity to Hazardous Facilities (Nuclear)

Orange Site B is located approximately 4,500 feet from a facility which contains potentially hazardous materials. A matrix rating of 12 was assigned.

6.3 SOCIOECONOMIC CONSIDERATIONS

6.3.1 Transportation

Same as Orange Site A, Section 5.3.1.

6.3.2 Community Impact

Same as Orange Site A, Section 5.3.2.

6.3.3 Archaeological and Historical Impact

Same as Section 5.3.3.

6.3.4 Visual Impact

Same as Section 5.3.4.

6.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

7 GEISMAR REGION - SITE A

7.1 TECHNICAL/ENGINEERING CONSIDERATIONS

7.1.1 Site Preparation

All four Geismar region sites are relatively flat with a slight dip in ground surface elevation away from the Mississippi River. Sites A, B, and D have varying amounts of heavily wooded and cattle grazing lands. Site C is almost entirely without heavy tree stands.

Nuclear plant requirements necessitate that poor bearing capacity soils be excavated to almost 100 feet and replaced by well-compacted backfill at all four Geismar sites. This massive excavation is further complicated by a need to dewater the excavation until building foundations and walls are poured up to grade. The groundwater level at the four Geismar sites fluctuates seasonally with the Mississippi River.⁽¹⁾ Much of the year the groundwater level is probably near the ground surface. Thus, construction dewatering must start at the beginning of excavation and operate for several years until plant construction reaches at least existing ground surface elevation. This would require an extremely large dewatering system, and the impact of construction dewatering operations on neighboring wells in the Geismar area must be thoroughly evaluated.

Pile foundations would be required in a fossil plant to bypass the soft clays and transfer structure loads to the dense alluvial sand.

The potential impact on the construction schedule due to required deep excavation or installation of very long piles for both nuclear or fossil plants leads to low matrix ratings at all four Geismar sites. Matrix ratings of 5 and 8 points were assigned for nuclear and fossil plants, respectively.

7.1.2 Proximity to Load Demand

This site is located at the north end of all steam customers and was rated 10 for Proximity to Load Demand. The distances from Site A to the steam users vary from 10,000 to 25,000 feet.

7.1.3 Water Availability

The Mississippi River is the potential source of water. The low-water flow of the Mississippi near Baton Rouge is approximately 100,000 cfs. The average flow of the

Mississippi is about 419,000 cfs with a maximum recorded flood flow of 2,280,000 cfs.

Ample water is available for the needs of the power plant. The maximum water consumption requirement of the plant is about 0.0007 percent of the average river flow. Therefore, a matrix rating of 20 was assigned to nuclear and fossil plants.

7.1.4 Highway, Rail, and Water Access

Baton Rouge is the major rail center. The Illinois Central Railroad traverses the site and the Illinois Central, Texas and Pacific, Louisiana and Arkansas, and South Shore Railroads serve the Mississippi region.

Interstate Highways 10 and 12 are the principal highways of this region. Interstate 10 connects New Orleans, Baton Rouge, and Lafayette; Interstate 12 runs in an east-west direction from Baton Rouge to Alabama. There are secondary routes linking Geismar to the Baton Rouge area.

The Mississippi River qualifies as a navigable waterway and in this region handles considerable annual tonnage of barge and ocean freighter traffic. The proximity of this site to a bend in the river creates potential hazards to river navigation and raises the question of feasible barge unloading of fuel. Detailed studies are required to affirm the suitability of the site for barge unloading. Preliminary review indicates matrix ratings of 5 for nuclear and 10 for fossil plants.

7.1.5 Foundations

Overexcavation and replacement with well-compacted backfill, required at all Geismar sites, minimize the concern for total and differential settlements, assure adequate static and dynamic bearing capacity, and preclude liquefaction during the design earthquakes for nuclear plants.

In order to construct a fossil plant at any Geismar site, pile foundations at least 100 feet long, with their tips at the top of the alluvial sand, would provide design capacities of about 50 to 60 tons. By driving the piles 10 to 20 feet into the alluvial sand, significantly higher pile capacities of up to 150 tons could be obtained, if required. However, handling and installing 110- to 120-foot long piles is expensive. Caissons are not economically competitive with pile foundations because of the high groundwater table, soft soil conditions, and large depth of penetration required.⁽³⁾

On the other hand, installation of a pile foundation for a fossil plant, in contrast to the required overexcavation and backfill required for a nuclear plant, is advantageous in that it does not require the installation and operation of a construction dewatering system.

Weighing these considerations, matrix ratings of 8 and 7 were assigned for nuclear and fossil plants, respectively, at all four Geismar sites.

7.1.6 Water Supply Systems

Along the river bank is a revetment and levee at this site. No special or unusual construction features are required for water systems other than routing the piping over the levee. The distance to the river is approximately 5,000 ft. Water supply systems for all Geismar sites were given a matrix rating of 8 for both plants.

7.1.7 Land Costs

The site is located next to an existing industrial community and land costs are expected to be less than North Baton Rouge but more than Orange. Because Site A is located on the river bend and is less conducive to barge loading and unloading, it would be less expensive than the other sites at Geismar. A matrix rating of 4 was assigned.

7.1.8 Steam Supply/Demand Match

The steam demand in the Geismar region is about 30 percent more than can be supplied by an intermediate-size LWR. All sites for nuclear plants in the region were rated 12. As stated in Section 1.1.8, all fossil plants were given the maximum matrix rating of 10.

7.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

7.2.1 Wastewater Impact

Same as the North Baton Rouge site (see Section 1.2.1). All Geismar sites were assigned maximum matrix ratings of 5 for nuclear and 10 for fossil plants, respectively.

7.2.2 Cooling Water Impact (Nuclear)

The high flow availability of the Mississippi River causes the impact from cooling water to produce a negligible effect on the river should emergency cooling be required. See Cooling Water Impact, Section 1.2.2. A matrix of 5 was assigned.

7.2.3 Land Use

Since Geismar Site A is zoned industrial and located adjacent to an industrial complex, the use of the site for a power plant is compatible with the surrounding area. Therefore, a matrix rating of 9 was assigned for both nuclear and fossil plants.

7.2.4 Land Requirements

Site A is the smallest of the Geismar sites (approximately 64 acres) and cannot support either a nuclear or fossil plant. Consequently, matrix ratings of 1 and 0 were assigned to nuclear and fossil plant land requirements, respectively.

Other siting factors are considered because the site may serve as reserve for developing future energy production alternatives.

7.2.5 Geology

The Geismar region, containing Sites A, B, C, and D, is dominated by its proximity to the Darrow salt dome located south of the proposed sites, and the St. Gabriel salt dome and oil and gas fields located to the north.^(5,6) Oil, gas, and brine are being extracted from the Darrow salt dome vicinity. The combined withdrawal of fluids north and south of the Geismar region sites is leading to widespread subsidence in this area.^(1,2) The four proposed Geismar sites are on the Mississippi River floodplain, and U.S. Army Corps of Engineers levees have been constructed to protect the area from flooding. Future widespread subsidence of several feet may necessitate increasing the height of the levees to ensure an adequate level of protection against floods.

The Lake Arthur fault zone is believed to be buried about 5 miles south of Geismar, trending in an east-west direction. The significance of this buried fault in nuclear plant licensing is likely to necessitate considerable offsite geological investigations.

The combination of nearby salt domes and a buried fault are indicators of possible development of slump faults in the Geismar area.

The subsurface stratigraphy in the Geismar region consists of soft Pleistocene clays and silts to a depth of approximately 100 feet, overlying dense alluvial sand deposits.⁽³⁾ There are thin sand lenses and layers within the Pleistocene deposits. The alluvial sand deposit is typically about 50 feet thick and provides an excellent

bearing stratum for deep foundations. Conversely, the 100-foot thick Pleistocene clay deposits are so soft that they would have to be excavated for a nuclear plant or bypassed with piles for a fossil plant. The presence of soft deposits below any coal storage yard may result in very stringent operating procedures on the storage of coal; i.e., the maximum height and rate at which the coal could be stacked may have to be carefully controlled so as to preclude a massive bearing capacity failure of the underlying soft clays. Alternatively, some of the soft clays could be excavated below any proposed coal storage pile and replaced with well-compacted backfill.

Liquefaction is not a licensing concern, assuming the soft Pleistocene clays were removed and replaced by a well-compacted backfill between excavation grade and the desired foundation grade.

As a result of the above review, matrix rating values of 15 and 12 were assigned for nuclear and fossil plants, respectively, at all Geismar sites.

7.2.6 Hydrology

As mentioned earlier, the Geismar site slopes slightly downward away from the Mississippi River levee. Immediately adjacent to the river, the elevation is about 25 feet above mean sea level. The elevation of the area ranges from about 16 to 20 feet above mean sea level. The levee in the area is about 15 feet higher than the adjacent land which provides a protective height of about 40 feet above mean sea level. The peak historical flow, occurring May 13, 1975, was 1,248,000 cfs, approximately three times the average annual flow rate.⁽¹⁾ The peak gage height occurred April 14, 1973, and reached a height of 35.8 feet above mean sea level.⁽¹⁾ Since the land elevation decreases with distance from the river, a nuclear plant would require protection against flooding either through elevating the grade, "hardening" any openings below elevation 35.8 feet, or both. The matrix rating of 16 was designated for nuclear plants and 12 for fossil plants.

7.2.7 Seismology

Refer to this topic under the North Baton Rouge region. Note that the epicenter of the "local" design earthquakes governing the OBE and SSE for Geismar was located at Donaldsonville, Louisiana, which is approximately 7 miles from the Geismar sites. Since the epicenter of the Donaldsonville earthquake is not precisely known, considerable investigation is anticipated to satisfactorily document this seismic event.

As previously indicated, matrix rating values of 20 and 10 were assigned to nuclear and fossil plants, respectively, for all four Geismar sites.

7.2.8 Meteorology

The meteorology is similar to North Baton Rouge (see Section 1.2.8). A matrix rating of 12 was assigned.

7.2.9 Ecology and Croplands

Generally, Geismar is surrounded by cultivated croplands and pasturelands. Major crops include corn, sweet potatoes, Irish potatoes, sugar cane, and soybeans. Natural flora include tupelo gum, bald cypress, hackberry, ash, box elder, and sycamore. There are no known endangered species in this area and no impact is expected since all discharges will meet applicable standards and will not threaten croplands or the ecology. A matrix rating of 8 was assigned to both nuclear and fossil plants.

7.2.10 Air Quality (Fossil)

The Geismar area ground-level concentrations with associated background levels and federal air quality standards are shown in Table A-3.⁽¹⁴⁾ Other studies performed for this area indicate that the air quality in this area will not impact the licensability of this site. The matrix rating assigned is 18.

TABLE A-3

GEISMAR AREA GROUND-LEVEL CONCENTRATION OF CONTAMINANTS
COMPARED TO NATIONAL AIR QUALITY STANDARDS

	<u>Concentration Background Levels</u>	<u>Primary Air Quality Standard</u>	<u>Secondary Air Quality Standard</u>
<u>Particulates, ug/m³</u>			
Annual average conc.	36*	75	60
Maximum 24-hr conc.	-	260	150
<u>Sulfur Dioxide, ppm</u>			
Annual average conc.	0.001*	0.03	0.02
Maximum 24-hr conc.	-	0.14	0.10
Maximum 3-hr conc.	-	-	0.50
<u>Nitrogen Oxides, ppm</u>			
Annual average conc.	0.032*	0.05	0.05

*Data supplied by Gulf States Utilities taken at three sites
in the St. Gabriel area for 1975.

7.2.11 Radiological Considerations (Nuclear)

Geismar Sites A, B, C, and D have a population center boundary distance of 18 miles. The population density (approximately 110 persons per square mile) within any reasonable LPZ makes the Geismar sites favorable for a nuclear plant location. Therefore, the Geismar sites received a high matrix rating of 25.

7.2.12 Demography (Nuclear)

Geismar Site A, located in south-central Louisiana, is 16 miles south-southeast of Baton Rouge. The current population within a 30-mile radius of the candidate site is about 313,000, reflecting a population density of 110 persons per square mile. It is estimated that this region will contain a population of about 709,000 by 2020. The town of Gonzales, located 6 miles east-northeast, is the closest population concentration and has a current population of approximately 6,250. Other population concentrations include Donaldsonville, located 7 miles south-southeast, with a current population of about 10,200, and Baton Rouge, located 16 miles north-northwest, with a current population of about 209,000. A matrix rating of 25 was assigned. The above demographic information is also applicable to Geismar Sites B, C, and D.

7.2.13 Noise Impact

The nearest residential community is Gonzales, located more than 4 miles away. Since the plant is situated in an industrial complex with relatively high ambient noise levels, no additional impact would be expected on the distant residential community. In accordance with this information, a matrix rating of 10 has been assigned to fossil plants, a rating of 5 to nuclear plants.

7.2.14 Proximity to Hazardous Facilities (Nuclear)

Geismar Site A is located approximately 3,000 feet from a facility that contains potentially hazardous materials. A matrix rating of 8 was assigned.

7.3 SOCIOECONOMIC CONSIDERATIONS

7.3.1 Transportation

The area has access to rail, highway, and water transportation, but as indicated in Section 7.1.4, use of the Mississippi River as a transportation corridor is in doubt. However, the impact on river traffic may be significant if fuel is unloaded by barge. There would be

little, if any, impact on rail or highway systems if fuel is delivered by rail and wastes are trucked away. All the Geismar sites have been assigned full-value transportation matrix ratings of 5 for fossil and 15 for nuclear plants.

7.3.2 Community Impact

As mentioned, Geismar Site A is located 16 miles from Baton Rouge (population approximately 209,000). Within 10 miles of the site are several towns with a total population of 17,000. Therefore, as stated in Section 1.3.2, the addition of construction workers plus their families (about 3,200 persons) should have little impact to the area's infrastructure. The transportation of men and equipment during plant construction should not affect the surrounding communities because of their distance from the site. A matrix rating of 10 was assigned for both nuclear and fossil plants.

7.3.3 Archaeological and Historical Impact

There are no known archaeological sites in the vicinity of Site A. The Belle Helene Plantation, a historic landmark, would not be affected because of its distance from the site. A matrix rating of 5 was assigned.

7.3.4 Visual Impact

The nearest residential community, Gonzales, is 6 miles from the site. The surrounding area is largely industrial, so the plant would not create any visual impact problems. Matrix ratings of 5 and 9 were applied to nuclear and fossil plants, respectively.

7.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

8 GEISMAR REGION - SITE B

8.1 TECHNICAL/ENGINEERING CONSIDERATIONS

8.1.1 Site Preparation

Refer to Site Preparation, Geismar Site A, Section 7.1.1.

8.1.2 Proximity to Load Demand

Site B lies north of the complex. The distance to steam users varies from 5,000 to 22,000 feet. Proximity to Load Demand was rated 20 for nuclear and 22 for fossil plants.

8.1.3 Water Availability

The site has the same excellent water availability as Geismar Site A, Section 7.1.3. The same matrix rating, 20, was assigned to both types of plants.

8.1.4 Highway, Rail, and Water Access

The site has access to highway, rail, and water transportation as mentioned in the discussion of Geismar Site A. Concerning water transportation, the site is better than Geismar Site A because it is farther from the river bend. It may be possible to utilize existing docking facilities of neighboring Shell and Wyandotte industrial complexes. The nuclear matrix rating remains the same as Site A; however, due to better water access, the matrix rating for fossil fuel is 23.

8.1.5 Foundations

Refer to Foundations, Geismar Site A, Section 7.1.5.

8.1.6 Water Supply Systems

Same as Geismar Site A.

8.1.7 Land Costs

Similar to Geismar Site A, but probably more expensive since barge unloading is feasible and, therefore, the property is more valuable. Matrix ratings of 3 were assigned.

8.1.8 Steam Supply/Demand Match

Refer to Steam Supply/Demand Match, Geismar Site A, Section 7.1.8.

8.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

8.2.1 Wastewater Impact

Same as Geismar Site A, Section 7.2.1.

8.2.2 Cooling Water Impact (Nuclear)

Same as Geismar Site A, Section 7.2.2.

8.2.3 Land Use

Same as Geismar Site A, Section 7.2.3.

8.2.4 Land Requirements

Site B is the largest Geismar site, comprising approximately 600 acres, an ample area to support a nuclear or fossil plant. Consequently, matrix ratings of 25 and 20 were assigned for fossil and nuclear plants, respectively.

8.2.5 Geology

Same as Geismar Site A, Section 7.2.5.

8.2.6 Hydrology

Same as Geismar Site A, Section 7.2.6.

8.2.7 Seismology

Refer to Section 1.2.7 and Geismar Site A, Section 7.2.7.

8.2.8 Meteorology

Same as Geismar Site A, Section 7.2.8.

8.2.9 Ecology and Croplands

Same as Geismar Site A, Section 7.2.9.

8.2.10 Air Quality (Fossil)

Same as Geismar Site A, Section 7.2.10.

8.2.11 Radiological Considerations (Nuclear)

See Section 7.2.11, Radiological Considerations.

8.2.12 Demography (Nuclear)

The demographic information contained in Section 7.2.12, Geismar Site A, is applicable.

8.2.13 Noise Impact

Same as Geismar Site A, Section 7.2.13.

8.2.14 Proximity to Hazardous Facilities (Nuclear)

Geismar Site B is located approximately 4,000 feet from a facility that contains potentially hazardous materials. A matrix rating of 12 was assigned.

8.3 SOCIOECONOMIC CONSIDERATIONS

8.3.1 Transportation

Assuming fuel is delivered by barge or rail, no significant impact is expected on any of the transportation corridors. Accordingly, full-value matrix ratings of 5 and 15 were assigned, respectively, to nuclear and fossil plants.

8.3.2 Community Impact

Same as Geismar Site A, Section 7.3.2.

8.3.3 Archaeological and Historical Impact

Same as Geismar Site A, Section 7.3.3.

8.3.4 Visual Impact

Same as Geismar Site A, Section 7.3.4.

8.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

9 GEISMAR REGION - SITE C

9.1 TECHNICAL/ENGINEERING CONSIDERATIONS

9.1.1 Site Preparation

Refer to Geismar Site A, Section 7.1.1.

9.1.2 Proximity to Load Demand

This site is centrally located (all steam users lie within a distance of 10,000 feet) and was given the maximum rating of 25.

9.1.3 Water Availability

Same as Geismar Site A.

9.1.4 Highway, Rail, and Water Access

Same as Geismar Site B.

9.1.5 Foundations

Refer to Geismar Site A, Section 7.1.5.

9.1.6 Water Supply Systems

Same as Geismar Sites A and B.

9.1.7 Land Costs

Same as Geismar Site B.

9.1.8 Steam Supply/Demand Match

Refer to Geismar Site A, Section 7.1.8.

9.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

9.2.1 Wastewater Impact

Same as Geismar Site A, Section 7.2.1.

9.2.2 Cooling Water Impact (Nuclear)

Same as Geismar Site A, Section 7.2.2.

9.2.3 Land Use

Same as Geismar Site A, Section 7.2.3.

9.2.4 Land Requirements

Site C contains approximately 500 acres and is able to support a nuclear or fossil plant. Consequently, matrix ratings of 25 and 20 were assigned for fossil and nuclear plant considerations, respectively.

9.2.5 Geology

Same as Geismar Site A, Section 7.2.5.

9.2.6 Hydrology

Same as Geismar Site A, Section 7.2.6.

9.2.7 Seismology

Refer to Section 1.2.7 and Geismar Site A, Section 7.2.7.

9.2.8 Meteorology

Same as Geismar Site A, Section 7.2.8.

9.2.9 Ecology and Croplands

Same as Geismar Site A, Section 7.2.9.

9.2.10 Air Quality (Fossil)

Same as Geismar Site A, Section 7.2.10.

9.2.11 Radiological Considerations (Nuclear)

Same as Geismar Site A, Section 7.2.11.

9.2.12 Demography (Nuclear)

The demographic information continued in Section 7.2.12, Geismar Site A, is applicable.

9.2.13 Noise Impact

Same as Geismar Site A, Section 7.2.13.

9.2.14 Proximity to Hazardous Facilities (Nuclear)

Geismar Site C is located approximately 2,100 feet from a facility that contains potentially hazardous materials. A matrix rating of 5 was assigned.

9.3 SOCIOECONOMIC CONSIDERATIONS

9.3.1 Transportation

Same as Geismar Site B, Section 8.3.1.

9.3.2 Community Impact

Same as Geismar Site A, Section 7.3.2.

9.3.3 Archaeological and Historical Impact

There are no known archaeological sites in this area. The proximity of the Belle Helene Plantation (less than 1 mile) to this site may present a historical siting impact. Although there is a buffer zone, a matrix rating of 4 was assigned.

9.3.4 Visual Impact

The site is quite far from any significant residential community (e.g., Gonzales is 6 miles distant). Due to plant visual impact of the Belle Helene Plantation, matrix ratings of 4 and 6 have been assigned to nuclear and fossil plants, respectively.

9.35 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

10 GEISMAR REGION - SITE D

10.1 TECHNICAL/ENGINEERING CONSIDERATIONS

10.1.1 Site Preparation

Refer to Geismar Site A, Section 7.1.1.

10.1.2 Proximity to Load Demand

Site D is south of all of the steam customers, and distances to them vary from 8,000 to 18,000 feet. The site was rated 10.

10.1.3 Water Availability

Same as other Geismar sites.

10.1.4 Highway, Rail, and Water Access

Same as Geismar Sites B and C.

10.1.5 Foundations

Refer to Geismar Site A, Section 7.1.5.

10.1.6 Water Supply Systems

Same as other Geismar sites.

10.1.7 Land Costs

The land costs and matrix rating would be similar to that for Geismar Sites B and C.

10.1.8 Steam Supply/Demand Match

Refer to Geismar Site A, Section 7.1.8.

10.2 PHYSICAL AND ENVIRONMENTAL/LICENSING CONSIDERATIONS

10.2.1 Wastewater Impact

Same as Section 7.2.1.

10.2.2 Cooling Water Impact (Nuclear)

Same as Section 7.2.2.

10.2.3 Land Use

The proximity of the Belle Helene Plantation, a historical landmark, to Geismar D may present siting problems. Matrix ratings of 6 and 5 were assigned for nuclear and fossil plants, respectively.

10.2.4 Land Requirements

Site D has a narrow configuration that limits its use for a nuclear plant site, and it has inadequate acreage (100 acres) for a fossil plant site. Consequently, matrix ratings of 2 and 0 were assigned for siting a nuclear and fossil plant, respectively. Other siting factors are considered, however, since the site may serve as reserve for developing future energy production alternatives.

10.2.5 Geology

Same as Section 7.2.5.

10.2.6 Hydrology

Same as Section 7.2.6.

10.2.7 Seismology

Same as Section 7.2.7.

10.2.8 Meteorology

Same as Section 7.2.8.

10.2.9 Ecology and Croplands

Same as Section 7.2.9.

10.2.10 Air Quality (Fossil)

Same as Section 7.2.10.

10.2.11 Radiological Considerations (Nuclear)

Same as Geismar Site A, Section 7.2.11.

10.2.12 Demography (Nuclear)

The demographic information contained in Section 7.2.12, Geismar Site A, is applicable.

10.2.13 Noise Impact

Same as Section 7.2.13.

10.2.14 Proximity to Hazardous Facilities (Nuclear)

Geismar Site D is located approximately 3,500 feet from a facility that has potentially hazardous materials. It was assigned a matrix rating of 10.

10.3 SOCIOECONOMIC CONSIDERATIONS

10.3.1 Transportation

As mentioned in Section 7.3.1 on Geismar Site A, this site has adequate access to rail, water, and highway transportation. Therefore, there should be no impact of fuel or waste transportation on nearby communities. We have assigned a matrix rating of 5 to a nuclear plant, 15 to a fossil plant.

10.3.2 Community Impact

Same as Geismar Site A, Section 7.3.2.

10.3.3 Archaeological and Historical Impact

There are no known archaeological sites in the region. However, the Belle Helene Plantation, located on the adjacent property, may present siting problems. Consequently, a matrix rating of 2 has been assigned for nuclear and fossil plants.

10.3.4 Visual Impact

The site is sufficiently distant from the residential community of Gonzales to exclude any visual impact. The plant may visually impact the Belle Helene Plantation. Matrix ratings of 3 for nuclear plants and 4 for fossil plants were applied.

10.3.5 Transmission/Steam Line Impact

Same as North Baton Rouge, Section 1.3.5.

11 REFERENCES

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14. Stone & Webster Engineering Corporation. Report on Air Quality Control for Geismar Station for Gulf States Utilities. Cherry Hill, New Jersey, March 1976.

APPENDIX B

LIST OF DRAWINGS

EM-1A	Site Plan - Interconnecting Piping and Cabling Geismar Area - GSU/ERDA Coal-Fired Plant
EM-1B	Site Plan - Interconnecting Piping and Cabling Geismar Area - GSU/ERDA Nuclear Plant
EM-1C	Site Plan - Interconnecting Piping and Cabling Geismar Area - GSU/ERDA Oil-Fired Plant
EM-1D	Site Plan - Interconnecting Piping and Cabling Orange Area - GSU/ERDA Coal-Fired Plant
EM-1E	Site Plan - Interconnecting Piping and Cabling Orange Area - GSU/ERDA Nuclear Plant
EM-1F	Site Plan - Interconnecting Piping and Cabling Orange Area - GSU/ERDA Oil-Fired Plant
EM-1G	GSU/ERDA Site Plan - Base Case for AFB Design
EM-1H	GSU/ERDA Boiler Room Side Elevation Base Case for AFB Design
EM-1I	GSU/ERDA Boiler Room Front Elevation Base Case for AFB Design
EM-1J	GSU/ERDA Site Plan - B&W Design for AFB Design
EM-1K	GSU/ERDA General Arrangement - Boiler Area - SH2 B&W Design for AFB Design
EM-1L	GSU/ERDA General Arrangement - Boiler Area - SH1 B&W Design for AFB Design
EM-1M	GSU/ERDA Composite Boiler Area - Section 2-2 SH2 B&W Design for AFB Design
EM-1N	GSU/ERDA Site Plan - F.W. Design for AFB Design
EM-1O	GSU/ERDA General Arrangement - Boiler Area - Section 1-1 SH 2 F.W. Design for AFB Design
EM-1P	GSU/ERDA General Arrangement - Boiler Area - Plan SH 1 F.W. Design for AFB Design
EM-1Q	GSU/ERDA Composite - Boiler Area - Section 3-3 F.W. Design for AFB Design
EP-2A	GSU/ERDA Typical Fundamental Flow Diagram for Waste and Water Treatment - Coal-Fired Plant
EP-2B	GSU/ERDA Typical Fundamental Flow Diagram for Waste and Water Treatment - Oil-Fired Plant
EP-2C	GSU/ERDA Typical Fundamental Flow Diagram for Bottom and Fly Ash Systems - Coal-Fired Plants
EP-2D	GSU/ERDA Typical Fundamental Flow Diagram for Oil-Fired Boiler Soot Handling System
EP-2E	Orange Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for Fossil Fuel Plants
EP-2F	Geismar Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for Fossil Fuel Plants

EP-2G	Orange Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for Consolidated Nuclear Steam Supply
EP-2H	Geismar Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for Consolidated Nuclear Steam Supply
EP-2I	Geismar Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for High Temperature Gas-Cooled Reactor Plant (HTGR Steamer)
EP-2J	Orange Area - GSU/ERDA Fundamental Heat Cycle Flow Diagram and Heat Balance for High Temperature Gas-Cooled Reactor Plant (HTGR Steamer)
EP-2R	GSU/ERDA - Geismar Area Moving Bed Coal Gasification Air Blown Block Flow Diagram
EP-2S	GSU/ERDA - Geismar Area Moving Bed Coal Gasification Oxygen Blown Block Flow Diagram
EP-2T	GSU/ERDA - Geismar Area Lurgi Air Blown Gasifier with Cold Purification, Gas Turbines, and Waste Heat Recovery Boiler (Unlimited Power Output)
EP-2U	GSU/ERDA - Geismar Area Lurgi Air Blown Gasifier with Cold Purification, Gas Turbine, Waste Heat Recovery Boiler, and Steam Generator (Limited Power Output)
EP-2V	GSU/ERDA - Geismar Area Lurgi Air Blown Gasifier with Cold Purification, Fuel Cell, and Waste Heat Recovery Boiler (Unlimited Power Output)
EP-2W	GSU/ERDA - Geismar Area Lurgi Air Blown Gasifier with Cold Purification, Fuel Cells, Waste Heat Recovery Boiler, and Steam Generator (Limited Power Output)
EP-2X	Schematic Diagram of Phosphoric Acid Fuel Cell
SK-1A	Orange Area - GSU/ERDA Fundamental Diagram of Coal Handling System
SK-1B	Geismar Area - GSU/ERDA Fundamental Diagram of Coal Handling System

12977-EM-IH

LEGEND

- WALL BLOWER
- LONG RETRACT BLOWER
- 18" ACCESS DOOR
- OBSERVATION DOOR
- 4" BLR NR'S TEST PROBE
- 2" FURNACE PRESS TAP
- GAS TEMP PROBE (THIS SIDE ONLY)
- WATER COOLED DOOR
- FUTURE

SIDE ELEVATION

NOTES
SCALE 1/8" = 1'-0"

COGENERATION FEASIBILITY STUDY
GSU/ERDA
BOILER ROOM SIDE ELEVATION
BASE CASE
FOR AFB DESIGN
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

12977-EM-IH

DESIGNED BY F. PERSIA
CHECKED BY

FRONT ELEVATION

NOTES
SCALE 1" = 1'-0"

COGENERATION FEASIBILITY STUDY
GSU/ERDA
BOILER ROOM FRONT ELEVATION
BASE CASE
FOR AFB DESIGN
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, NJ

12977-EM-1 I

DESIGNED BY F. PERSIA
CHECKED BY

PLAN

COGENERATION FEASIBILITY STUDY
 GSU/ERDA
 GENERAL ARRANGEMENT-BOILER AREA-SH I
 B & W DESIGN
 FOR AFB DESIGN
 STONE & WEBSTER ENGINEERING CORPORATION
 CHERRY HILL, N.J.
 12977-EM-IL

12977-EM-1M

NOTES:
1. SCALE: 1/8"=1'-0"

COGENERATION FEASIBILITY STUDY
GSU/ERDA
COMPOSITE-BOILER AREA-SECT 2-2-SH 2
B & W DESIGN
FOR AFB DESIGN
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, NJ

12977-EM-1M

DESIGNED BY: F. PERISA
CHECKED BY: []
DATE: []

NOTES
1. SCALE: 1/8" = 1'-0"

COGENERATION FEASIBILITY STUDY
GSU/ERDA
GENERAL AIRGT-BOILER AREA-SECTION I-I SH 2
F.W. DESIGN
FOR AFB DESIGN
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

12977-EM-10

DESIGNED BY: F. PERSIA
CHECKED BY: J. C. BIRLOTTI

NOTES:
1. SCALE: 1/8" = 1'-0"

COGENERATION FEASIBILITY STUDY
GSU/ERDA
GENERAL ARRGT-BOILER AREA-PLAN SH I
F.W. DESIGN
FOR AFB DESIGN

STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, NJ

12977-EM-IP

DESIGNED BY: PERSIA
CHECKED BY: PERSIA
DATE: 10/10/83

COGENERATION FEASIBILITY STUDY
GSU/ERDA
TYPICAL FUNDAMENTAL FLOW
DIAGRAM FOR WASTE AND WATER
TREATMENT-COAL FIRED PLANT
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2A

DESIGNED BY F. PERSIA
CHECKED BY

COGENERATION FEASIBILITY STUDY
GSU/ERDA
TYPICAL FUNDAMENTAL FLOW
DIAGRAM FOR WASTE AND WATER
TREATMENT-OIL FIRED PLANT
STONE & WEBSTER ENGINEERING CORPORATION
CERRELL, N.J.

12977-EP-2B

DESIGNED BY: F. PERSIA
CHECKED BY: J. CIRILLO

COGENERATION FEASIBILITY STUDY
 GSU/ERDA
 TYPICAL FUNDAMENTAL FLOW
 DIAGRAM FOR BOTTOM AND FLY
 ASH SYSTEMS-COAL FIRED PLANTS
 STONE & WEBSTER ENGINEERING CORPORATION
 CHERRY HILL, N.J.

12977-EP-2C

A.J. CIRILLO

COGENERATION FEASIBILITY STUDY
GSU/ERDA
TYPICAL FUNDAMENTAL FLOW
DIAGRAM FOR OIL FIRED BOILER
SOOT HANDLING SYSTEM

STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2D

DESIGNED BY F. PERSTA
CHECKED BY

HEAT INPUT = 989.36 MWt

COGENERATION FEASIBILITY STUDY
ORANGE AREA - GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE
FOR FOSSIL FUEL PLANTS

STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2E

DESIGNED BY: P. PERSIA
CHECKED BY: M. MACCARELLA

12977-EP-2F

HEAT INPUT = 2630.958 MWt

COGENERATION FEASIBILITY STUDY
GEISMAR AREA - GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE
FOR FOSSIL FUEL PLANTS

ATYNE & WINTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2F

DESIGNED BY F. PERSIA CHECKED BY MACCARELLA

NO.	REVISION	DATE	DESCRIPTION	BY	CHKD.	APP'D.	DATE	NO.	REVISION	DATE	DESCRIPTION	BY	CHKD.	APP'D.	DATE	NO.	REVISION	DATE	DESCRIPTION	BY	CHKD.	APP'D.	DATE
1								1								1

TOTAL 42.86 GROSS MW GENERATION
(WITHOUT CONDENSING)
HEAT INPUT - CNSS 755.523 MWt
SUPERHEATER 115.56 MWt

COGENERATION FEASIBILITY STUDY
ORANGE AREA-GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
CONSOLIDATED NUCLEAR STEAM SUPPLY
ATPONE & WENSTER ENGINEERING CORPORATION
CHERRY HILL, NJ

DRAWING NUMBER 12977-EP-2G

DESIGNED BY A. LUECKE
CHECKED BY J. MACCARELLA
DATE 04/01/87

12977-EP-2H

TOTAL 90.8 GROSS MW GENERATION (WITHOUT CONDENSING)
HEAT INPUT - CNSS 1898.985 MWt
SUPERHEATER 345.489 MWt
BOILER 126.806 MWt

COGENERATION FEASIBILITY STUDY
GEISMAR AREA-GSU/ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
CONSOLIDATED NUCLEAR STEAM SUPPLY

ATONK & WEHNER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2H

DESIGNED BY A. LUECKE
CHECKED BY J. L. LUECKE
DRAWN BY J. L. LUECKE
DATE 10-1-77

COGENERATION FEASIBILITY STUDY
GFISMAR AREA - GSU/ ERDA
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
HIGH TEMP. GAS-COOLED REACTOR PLANT
(HTGR STEAMER)

ORATING NUMBER 12977-EP-2 I

DESIGNED BY	DRAWN BY	AREA	LEVELS	NO.
ORION CHARD BY	CHARD BY			

12977-EP-2J

HEAT INPUT 1007.363 MWt

COGENERATION FEASIBILITY STUDY
(RANGE AREA - GSH/ERDA)
FUNDAMENTAL HEAT CYCLE FLOW
DIAGRAM AND HEAT BALANCE FOR
HIGH TEMP. GAS-COOLED REACTOR PLANT
(HTGR STEAMER)

ATOMIC & WASTE ENGINEERING CORPORATION
CHERRY HILL, N.J.

DRAWING NUMBER 12977-EP-2J

DESIGNED BY C. GASS

AREA LEVELS WORKSHEET

12977-EP-2R

COGENERATION FEASIBILITY STUDY
GSU/ERDA-GEISMAR AREA
MOVING BED COAL GASIFICATION
AIR BLOWN
BLOCK FLOW DIAGRAM

STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

DESIGNED BY: MACCARELLA
DRAWN BY: J. J. CERIELLO
CHECKED BY: J. J. CERIELLO
DATE: 12/1/81

12977-EP-2R

12977-EP-25

- NOTES:
1. FLOWS SHOWN ARE FOR 100% CAPACITY OPERATION.
 2. STREAM HEAT CONTENTS INCLUDE HIGHER HEATING VALUE AND SENSIBLE HEAT ABOVE 60° F.
 3. EXPORT POWER IS GROSS POWER RECOVERED LESS PLANT POWER CONSUMPTION.

COGENERATION FEASIBILITY STUDY
GSU/ERDA-GEISMAR AREA
MOVING BED COAL GASIFICATION
OXYGEN BLOWN
BLOCK FLOW DIAGRAM

STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

12977-EP-25

DESIGNED BY: MACCARELLA, J. J. CHECKED BY: J. J. MACCARELLA, J. J. DATE: 10/1/81

COGENERATION FEASIBILITY STUDY
GSU/ERDA-GEISMAR AREA
Lurgi Air Blown Gasifier with Cold
Purification, Gas Turbines & Waste Heat
Recovery Boiler
(UNLIMITED POWER OUTPUT)
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.

12977-EP-2T

DESIGNED BY: MACCARELLA

CHECKED BY: [Signature]

12977-EP-2U

NOTES:
 • AS RECEIVED BASIS (1,113,262 LB/HR MOISTURE & ASH FREE)

TOTAL NET POWER GENERATION 352 MW_e

COGENERATION FEASIBILITY STUDY
 GSU/ERDA-GEISMAR AREA
 LURGI AIR BLOWN GASIFIER WITH COLD
 PURIFICATION, GAS TURBINE, WASTE HEAT
 RECOVERY BOILER & STEAM GENERATOR
 (LIMITED POWER OUTPUT)
 STONE & WEBSTER ENGINEERING CORPORATION
 CHERRY HILL, NJ

12977-EP-2U

12977-EP-2W

NOTES:
 • AS RECEIVED (1,079,009 LB/HR MOISTURE & ASH FREE)

COGENERATION FEASIBILITY STUDY
 GSA/ERDA-GEISMAR AREA
 LURGI AIR BLOWN GASIFIER WITH COLD
 PURIFICATION, FUEL CELLS, WASTE HEAT
 RECOVERY BOILER & STEAM GENERATOR
 (LIMITED POWER OUTPUT)
 STONE & WEBSTER ENGINEERING CORPORATION
 CHERRY HILL, NJ
 12977-EP-2W

COGENERATION FEASIBILITY STUDY
 SCHEMATIC DIAGRAM
 OF PHOSPHORIC ACID FUEL CELL
 12977-EP-2X

COGENERATION FEASIBILITY STUDY
 ORANGE AREA GSU/ERDA
 FUNDAMENTAL DIAGRAM OF
 COAL HANDLING SYSTEM

STONE & WEBSTER ENGINEERING CORPORATION

7	6	5	4	3	2	1	M
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12977 SK-1A

COGENERATION FEASIBILITY STUDY
 GEISMAR AREA GSU/ERDA
 FUNDAMENTAL DIAGRAM OF
 COAL HANDLING SYSTEM
 STONE & WEBSTER ENGINEERING CORPORATION
 12977 SK-1B

APPENDIX C

DISCOUNTED CASH FLOW ANALYSIS

Cash flow summary statements for 90, 100, 150, and 200 percent of the estimated fuel costs are included in this appendix. The analysis was adapted with minor changes from the method described in Section 4 of References 27 and 28. All cash flows are reported in current end-of-year dollars. In the following paragraphs, the entries in each column are defined.

Column (1) - Capital Expense

Capital expense cash flow is determined from the estimated total capital investment and schedule of expenditures. Construction of the fossil-fired plants is delayed so that the first year of operation of all plants is 1986. The estimates in January 1978 dollars have been apportioned to the appropriate year and escalated at an annual rate of 7 percent. Land expense is included in the first year of construction and returned in 2015 at its escalated value.

Column (2) - Backup Expenses

Backup operating expense is assumed to be the current cost (net-of-taxes) of No. 2 fuel oil burned in existing facilities to compensate for study plant unavailability or differences in operating life. These costs have been excluded in this study in order to arrive at comparative costs solely for the alternative steam sources. For the CNSS, this column was used for the cost of No. 6 fuel oil, net-of-taxes.

Column (3) - Working Capital

Working capital has been estimated for a 60-day inventory of fossil fuel. An allowance for capital charges has been included in the cost of nuclear fuel, and is excluded here.

The escalated estimate is entered in the year prior to operation. The net change in subsequent years is the escalation to maintain constant value in current dollars. Total working capital is returned in the last year of operation.

Column (4) - Investment Cash Flow

Investment cash flow is the sum of columns (1), (2), and (3): Capital expense, backup expenses, and working capital.

Column (5) - Fuel Expenses

The cost of primary fuel in current dollars is entered in this column. Escalation rates are 6 percent for coal and 7 percent per year for oil. Nuclear fuel costs have been escalated at a composite rate of 4.9 percent based on 1/3 escalating at 6 percent and 2/3 escalating at 4 percent. Column (2) was used for the No. 6 fuel oil consumed for superheating and making high pressure steam in the CNSS plants because it escalates at a rate different from nuclear fuel. Entries in Column (5) are before taxes; those in Column (2) are net-of-taxes.

Column (6) Other Operating Expenses

Entries in column (6) are estimates of the wages and material costs for operating the plant exclusive of fuel. Auxiliary power is provided by the plant and does not represent a cash flow. It does reduce the credit for power generated shown in Column (9).

Column (7) - Taxes Other Than Income

At Geismar, taxes other than income tax are calculated at 2.0 percent of total capital cost, beginning in the eleventh year after first operation. At Orange, taxes begin in the first year and have been calculated as 1 percent of the current year's capital cash flow plus 2 percent of total prior expenditures.

Column (8) - Tax Depreciation

Capital expenditures exclusive of land costs are depreciated over a 22.5-year tax life. The first two years are depreciated by the double declining balance method and the remaining 20.5 years by the sum-of-the year's digits method.

Column (9) - Credit for Power

The net power generated is multiplied by the cost of power for large industrial users in the Gulf States Utilities area and entered in the column. After 1986, escalation is estimated to be at an annual rate of 7 percent.

Column (10) - Total Expenses Before Tax

Column (10) is the sum of Columns (5), (6), (7), (8), and (9) -

Column (11) - Total Expenses Before Tax

Column (11) is Column (10) brought forward.

Column (12) - Income Tax

Column (12) is computed as Column (11) times the income tax rate. The federal income tax rate is 46.0 percent. At Geismar, there is also a Louisiana state income tax of 8.0 percent. Because these taxes are mutually deductible, the effective income tax rate at Geismar is 48.4 percent.

Column (13) - Total Expenses After Tax

Column (13) is the sum of Columns (11) and (12).

Column (14) - Tax Depreciation

The tax depreciation shown in Column (8) as an expense for tax purposes is entered here as a cash in-flow.

Column (15) - Investment Tax Credit

The investment tax credit is calculated as 10 percent of the amount in Column (1) exclusive of land costs.

Column (16) - Operating Cash Flow

Column (16) is the sum of Columns (13), (14), and (15). It is the total expense charged to operations reduced by income tax credits.

Column (17) - Net Cash Flow

Column (17) is the sum of investment cash flow, Column (4), and operating cash flow, Column (16).

Columns (18), (19), (20) - Present Worth-Net Cash Flow (NCF)

These columns are the net present worth of the cash flows in Column (17) discounted at 10, 15, and 20 percent, respectively.

APPENDIX C
PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

Geismar

PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
90% FUEL COST

C-4

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX (NON-CASH)	(9) CREDIT FOR POKER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15685	0	0	-15685	0	0	0	0	0	0
1981	-21855	0	0	-21855	0	0	0	0	0	0
1982	-42090	0	0	-42090	0	0	0	0	0	0
1983	-280202	0	0	-280202	0	0	0	0	0	0
1984	-385462	0	0	-385462	0	0	0	0	0	0
1985	-319889	0	-26595	-346484	0	0	0	0	0	0
1986	0	0	-1596	-1596	-138913	-40336	0	-94416	113014	-160651
1987	0	0	-1691	-1691	-147248	-42756	0	-86024	120925	-155103
1988	0	0	-1793	-1793	-156083	-45322	0	-81976	129390	-153991
1989	0	0	-1901	-1901	-165448	-48041	0	-77977	138447	-153019
1990	0	0	-2015	-2015	-175374	-50923	0	-73978	148138	-152138
1991	0	0	-2135	-2135	-185897	-53979	0	-69980	158508	-151347
1992	0	0	-2264	-2264	-197051	-57217	0	-65981	169604	-150645
1993	0	0	-2399	-2399	-208874	-60650	0	-61982	181476	-150030
1994	0	0	-2543	-2543	-221406	-64289	0	-57983	194179	-149500
1995	0	0	-2696	-2696	-234691	-68147	0	-53984	207772	-149050
1996	0	0	-2858	-2858	-248772	-72236	-21304	-49985	222316	-169981
1997	0	0	-3029	-3029	-263698	-76570	-21304	-49987	237878	-169681
1998	0	0	-3211	-3211	-279520	-81164	-21304	-41988	254529	-169446
1999	0	0	-3404	-3404	-296291	-86034	-21304	-37989	272346	-169272
2000	0	0	-3608	-3608	-314069	-91196	-21304	-33990	291410	-169148
2001	0	0	-3824	-3824	-332913	-96668	-21304	-29991	311809	-169066
2002	0	0	-4054	-4054	-352888	-102468	-21304	-25992	333636	-169016
2003	0	0	-4297	-4297	-374061	-108616	-21304	-21994	356990	-168984
2004	0	0	-4555	-4555	-396505	-115133	-21304	-17995	381990	-168956
2005	0	0	-4828	-4828	-420295	-122041	-21304	-13996	408718	-168917
2006	0	0	-5118	-5118	-445513	-129363	-21304	-9997	437329	-168848
2007	0	0	-5425	-5425	-472244	-137125	-21304	-5998	467942	-168729
2008	0	0	-5750	-5750	-500578	-145352	-21304	-1999	500697	-168536
2009	0	0	-6095	-6095	-530613	-154073	-21304	0	535746	-170244
2010	0	0	-6461	-6461	-562450	-163318	-21304	0	573249	-173823
2011	0	0	-6849	-6849	-596197	-173117	-21304	0	613376	-177241
2012	0	0	-7259	-7259	-631968	-183504	-21304	0	656312	-180464
2013	0	0	-7695	-7695	-669887	-194514	-21304	0	702254	-183450
2014	0	0	-8157	-8157	-710080	-206185	-21304	0	751412	-186156
2015	19135	0	144101	163237	-752685	-218556	-21304	0	804011	-188534
TOTALS	-1046047	0	0	-1046051	-10982210	-3188891	-426073	-1062183	10675393	-4983965

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1268	1267	-14417	-11915	-10901	-10012
1981	0	0	0	0	2186	2185	-19669	-14778	-12933	-11383
1982	0	0	0	0	4209	4208	-37881	-25873	-21659	-18268
1983	0	0	0	0	28020	28019	-252182	-156585	-125379	-101346
1984	0	0	0	0	38546	38545	-346916	-195825	-149981	-116181
1985	0	0	0	0	31989	31988	-314495	-161386	-118230	-87770
1986	-160651	77755	-82896	94416	0	11519	9923	4628	3243	2307
1987	-155103	75069	-80034	86024	0	5989	4298	1822	1221	832
1988	-153991	74531	-79460	81976	0	2515	722	277	177	116
1989	-153019	74061	-78958	77977	0	-981	-2882	-1010	-619	-388
1990	-152138	73634	-78504	73978	0	-4526	-6541	-2084	-1223	-734
1991	-151347	73252	-78095	69980	0	-8115	-10250	-2969	-1666	-958
1992	-150645	72912	-77733	65981	0	-11752	-14016	-3691	-1981	-1092
1993	-150030	72614	-77416	61982	0	-15434	-17833	-4269	-2192	-1157
1994	-149500	72357	-77143	57983	0	-19160	-21703	-4723	-2319	-1174
1995	-149050	72140	-76910	53984	0	-22926	-25622	-5069	-2381	-1155
1996	-169981	82270	-87711	49985	0	-37726	-40584	-7299	-3279	-1524
1997	-169681	82125	-87556	45987	0	-41569	-44598	-7292	-3134	-1396
1998	-169446	82012	-87434	41988	0	-45446	-48657	-7233	-2973	-1269
1999	-169272	81927	-87345	37989	0	-49356	-52760	-7129	-2803	-1147
2000	-169148	81867	-87281	33990	0	-53291	-56899	-6990	-2629	-1031
2001	-169066	81828	-87238	29991	0	-57247	-61071	-6820	-2453	-922
2002	-169016	81803	-87213	25992	0	-61221	-65275	-6627	-2280	-821
2003	-168984	81788	-87196	21994	0	-65202	-69499	-6414	-2111	-729
2004	-168956	81774	-87182	17995	0	-69187	-73742	-6187	-1948	-644
2005	-168917	81755	-87162	13996	0	-73166	-77994	-5949	-1792	-568
2006	-168848	81722	-87126	9997	0	-77129	-82247	-5703	-1603	-499
2007	-168729	81664	-87065	5998	0	-81067	-86492	-5452	-1502	-437
2008	-168536	81571	-86965	1999	0	-84966	-90716	-5199	-1370	-382
2009	-170244	82397	-87847	0	0	-87847	-93942	-4894	-1234	-330
2010	-173823	84130	-89693	0	0	-89693	-96154	-4554	-1098	-281
2011	-177241	85784	-91457	0	0	-91457	-98306	-4233	-976	-240
2012	-180464	87344	-93120	0	0	-93120	-100379	-3929	-867	-204
2013	-183450	88789	-94661	0	0	-94661	-102356	-3642	-769	-173
2014	-186156	90099	-96057	0	0	-96057	-104214	-3371	-680	-147
2015	-188534	91250	-97284	0	0	-97284	-65952	-1939	-373	-77
TOTALS	-4983965	2412224	-2571742	1062183	106218	-1403341	-2449397	-690414	-481969	-361008

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.060)	(6) OTHER EXPENSES (ER \$.060)	(7) TAXES OTHER INCOME (ER \$.060)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15685	0	0	-15685	0	0	0	0	0	0
1981	-21855	0	0	-21855	0	0	0	0	0	0
1982	-42090	0	0	-42090	0	0	0	0	0	0
1983	-280202	0	0	-280202	0	0	0	0	0	0
1984	-385462	0	0	-385462	0	0	0	0	0	0
1985	-319889	0	-26595	-346484	0	0	0	0	0	0
1986	0	0	-1596	-1596	-154348	-40336	0	-94416	113014	-176086
1987	0	0	-1691	-1691	-163609	-42756	0	-86024	120925	-171464
1988	0	0	-1793	-1793	-173425	-45322	0	-81976	129390	-171333
1989	0	0	-1901	-1901	-183831	-48041	0	-77977	138407	-171402
1990	0	0	-2015	-2015	-194861	-50923	0	-73978	148138	-171624
1991	0	0	-2135	-2135	-206552	-53979	0	-69980	158508	-172003
1992	0	0	-2264	-2264	-218946	-57217	0	-65981	169604	-172540
1993	0	0	-2399	-2399	-232082	-60650	0	-61982	181476	-173239
1994	0	0	-2543	-2543	-246007	-64289	0	-57983	194179	-174101
1995	0	0	-2696	-2696	-260768	-68147	0	-53984	207772	-175127
1996	0	0	-2858	-2858	-276414	-72236	-21304	-49985	222316	-197623
1997	0	0	-3029	-3029	-292999	-76570	-21304	-45987	237878	-198981
1998	0	0	-3211	-3211	-310579	-81164	-21304	-41988	254529	-200505
1999	0	0	-3404	-3404	-329213	-86034	-21304	-37989	272346	-202193
2000	0	0	-3608	-3608	-348966	-91196	-21304	-33990	291410	-204045
2001	0	0	-3824	-3824	-369904	-96668	-21304	-29991	311869	-206057
2002	0	0	-4054	-4054	-392098	-102468	-21304	-25992	333636	-208226
2003	0	0	-4297	-4297	-415624	-108616	-21304	-21994	356990	-210547
2004	0	0	-4555	-4555	-440562	-115133	-21304	-17995	381920	-213013
2005	0	0	-4828	-4828	-466995	-122041	-21304	-13996	408718	-215617
2006	0	0	-5118	-5118	-495015	-129363	-21304	-9997	437329	-218350
2007	0	0	-5425	-5425	-524716	-137125	-21304	-5998	467902	-221201
2008	0	0	-5750	-5750	-556199	-145352	-21304	-1999	500697	-224157
2009	0	0	-6095	-6095	-589571	-154073	-21304	0	535746	-229202
2010	0	0	-6461	-6461	-624945	-163318	-21304	0	573249	-236318
2011	0	0	-6849	-6849	-662442	-173117	-21304	0	613376	-243486
2012	0	0	-7259	-7259	-702188	-183504	-21304	0	656212	-250684
2013	0	0	-7695	-7695	-744320	-194514	-21304	0	702244	-257883
2014	0	0	-8157	-8157	-788979	-206185	-21304	0	751412	-265055
2015	19135	0	144101	163237	-836317	-218556	-21304	0	804011	-272166
TOTALS	-1046047	0	0	-1046051	-12202474	-3188891	-426073	-1062183	10675393	-6204228

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1268	1267	-14417	-11915	-10901	-10012
1981	0	0	0	0	2186	2185	-19669	-14778	-12933	-11383
1982	0	0	0	0	4209	4208	-37881	-25873	-21659	-18268
1983	0	0	0	0	28020	28019	-252182	-156585	-125379	-101346
1984	0	0	0	0	38546	38545	-346916	-195825	-149981	-116181
1985	0	0	0	0	31989	31988	-314495	-161386	-118230	-87770
1986	-176086	85225	-90861	94416	0	3554	1958	912	639	454
1987	-171464	82988	-88476	86024	0	-2452	-4143	-1757	-1178	-803
1988	-171333	82925	-88408	81976	0	-6432	-8225	-3171	-2033	-1328
1989	-171402	82958	-88444	77977	0	-10467	-12368	-4335	-2658	-1665
1990	-171624	83066	-88558	73978	0	-14580	-16595	-5288	-3162	-1861
1991	-172003	83249	-88754	69980	0	-18774	-20909	-6057	-3398	-1954
1992	-172540	83509	-89031	65981	0	-23050	-25314	-6666	-3578	-1972
1993	-173239	83847	-89392	61982	0	-27410	-29809	-7136	-3663	-1935
1994	-174101	84264	-89837	57983	0	-31854	-34397	-7486	-3676	-1860
1995	-175127	84761	-90366	53984	0	-36382	-39078	-7731	-3631	-1761
1996	-197623	95649	-101974	49985	0	-51989	-54847	-9865	-4432	-2060
1997	-198981	96306	-102675	45987	0	-56688	-59717	-9764	-4196	-1869
1998	-200505	97044	-103461	41988	0	-61473	-64684	-9615	-3952	-1687
1999	-202193	97861	-104332	37989	0	-66343	-69747	-9425	-3706	-1516
2000	-204045	98757	-105288	33990	0	-71298	-74906	-9202	-3461	-1357
2001	-206057	99731	-106326	29991	0	-76335	-80159	-8952	-3226	-1210
2002	-208226	100781	-107445	25992	0	-81453	-85507	-8681	-2987	-1076
2003	-210547	101904	-108643	21994	0	-86649	-90946	-8394	-2763	-953
2004	-213013	103098	-109915	17995	0	-91920	-96475	-8095	-2508	-843
2005	-215617	104358	-111259	13996	0	-97263	-102091	-7787	-2305	-743
2006	-218350	105681	-112669	9997	0	-102672	-107790	-7475	-2153	-654
2007	-221201	107061	-114140	5998	0	-108142	-113567	-7159	-1972	-574
2008	-224157	108491	-115666	1999	0	-113667	-119417	-6844	-1804	-503
2009	-229202	110933	-118269	0	0	-118269	-124364	-6479	-1633	-437
2010	-236316	114377	-121941	0	0	-121941	-128402	-6081	-1466	-376
2011	-243486	117847	-125639	0	0	-125639	-132488	-5705	-1316	-323
2012	-250684	121330	-129354	0	0	-129354	-136613	-5347	-1180	-278
2013	-257883	124815	-133068	0	0	-133068	-140763	-5009	-1057	-238
2014	-265055	128286	-136769	0	0	-136769	-144926	-4688	-946	-204
2015	-272166	131728	-140438	0	0	-140438	22798	669	128	26
TOTALS	-6204228	3002930	-3201398	1062183	106218	-2032997	-3079051	-758953	-512351	-376501

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.060)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POKER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15685	0	0	-15685	0	0	0	0	0	0
1981	-21855	0	0	-21855	0	0	0	0	0	0
1982	-42090	0	0	-42090	0	0	0	0	0	0
1983	-280202	0	0	-280202	0	0	0	0	0	0
1984	-385462	0	0	-385462	0	0	0	0	0	0
1985	-319889	0	-26595	-346484	0	0	0	0	0	0
1986	0	0	-1596	-1596	-231522	-40336	0	-94416	113014	-253260
1987	0	0	-1691	-1691	-245413	-42756	0	-86024	120925	-253268
1988	0	0	-1793	-1793	-260138	-45322	0	-81976	129390	-258046
1989	0	0	-1901	-1901	-275746	-48041	0	-77977	138447	-263317
1990	0	0	-2015	-2015	-292291	-50923	0	-73978	148118	-269055
1991	0	0	-2135	-2135	-309829	-53979	0	-69980	158508	-275279
1992	0	0	-2264	-2264	-328418	-57217	0	-65981	169604	-282013
1993	0	0	-2399	-2399	-348123	-60650	0	-61982	181476	-289280
1994	0	0	-2543	-2543	-369011	-64289	0	-57983	194179	-297104
1995	0	0	-2696	-2696	-391152	-68147	0	-53984	207772	-305511
1996	0	0	-2858	-2858	-414621	-72236	-21304	-49985	222316	-335830
1997	0	0	-3029	-3029	-439498	-76570	-21304	-45987	237878	-345480
1998	0	0	-3211	-3211	-465868	-81164	-21304	-41988	254529	-355794
1999	0	0	-3404	-3404	-493820	-86034	-21304	-37989	272346	-366800
2000	0	0	-3608	-3608	-523449	-91196	-21304	-33990	291410	-378528
2001	0	0	-3824	-3824	-554856	-96668	-21304	-29991	311809	-391009
2002	0	0	-4054	-4054	-588147	-102468	-21304	-25992	333636	-404275
2003	0	0	-4297	-4297	-623436	-108616	-21304	-21994	356990	-418359
2004	0	0	-4555	-4555	-660842	-115133	-21304	-17995	381980	-433294
2005	0	0	-4828	-4828	-700493	-122041	-21304	-13996	408718	-449115
2006	0	0	-5118	-5118	-742522	-129363	-21304	-9997	437329	-465858
2007	0	0	-5425	-5425	-787074	-137125	-21304	-5998	467942	-483559
2008	0	0	-5750	-5750	-834298	-145352	-21304	-1999	500697	-502256
2009	0	0	-6095	-6095	-884356	-154073	-21304	0	535746	-523987
2010	0	0	-6461	-6461	-937417	-163318	-21304	0	573249	-548790
2011	0	0	-6849	-6849	-993663	-173117	-21304	0	613376	-574707
2012	0	0	-7259	-7259	-1053282	-183504	-21304	0	656312	-601778
2013	0	0	-7695	-7695	-1116479	-194514	-21304	0	702254	-630043
2014	0	0	-8157	-8157	-1183468	-206185	-21304	0	751412	-659545
2015	19135	0	144101	163237	-1254476	-218556	-21304	0	804011	-690325
TOTALS	-1046047	0	0	-1046051	-18303710	-3188891	-426073	-1062183	10675393	-12305465

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : EASTERN COAL
150% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=,10)	(19) PRESENT WORTH=NCF (DR=,15)	(20) PRESENT WORTH=NCF (DR=,20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1268	1267	-14417	-11915	-10901	-10012
1981	0	0	0	0	2186	2185	-19669	-14778	-12933	-11383
1982	0	0	0	0	4209	4208	-37881	-25873	-21659	-18268
1983	0	0	0	0	28020	28019	-252182	-156585	-125379	-101346
1984	0	0	0	0	38546	38545	-346916	-195825	-149941	-116181
1985	0	0	0	0	31989	31988	-314495	-161386	-118210	-87770
1986	-253260	122577	-130683	94416	0	-36267	-37863	-17663	-12377	-8806
1987	-253268	122581	-130687	86024	0	-44663	-46354	-19659	-13177	-8984
1988	-258046	124894	-133152	81976	0	-51176	-52969	-20422	-13093	-8555
1989	-263317	127445	-135872	77977	0	-57895	-59796	-20958	-12853	-8046
1990	-269055	130222	-138833	73978	0	-64855	-66870	-21307	-12498	-7500
1991	-275279	133235	-142044	69980	0	-72064	-74199	-21493	-12059	-6935
1992	-282013	136494	-145519	65981	0	-79538	-81802	-21541	-11561	-6371
1993	-289280	140011	-149269	61982	0	-87287	-89686	-21470	-11022	-5821
1994	-297104	143798	-153306	57983	0	-95323	-97866	-21298	-10458	-5293
1995	-305511	147867	-157644	53984	0	-103660	-106356	-21042	-9883	-4794
1996	-335830	162541	-173289	49985	0	-123304	-126162	-22691	-10195	-4739
1997	-345480	167212	-178268	45987	0	-132281	-135310	-22124	-9508	-4235
1998	-355794	172204	-183590	41988	0	-141602	-144813	-21526	-8808	-3777
1999	-366800	177531	-189269	37989	0	-151280	-154684	-20903	-8218	-3362
2000	-378528	183207	-195321	33990	0	-161331	-164939	-20262	-7620	-2988
2001	-391009	189248	-201761	29991	0	-171770	-175594	-19610	-7054	-2651
2002	-404275	195669	-208606	25992	0	-182614	-186668	-18952	-6521	-2348
2003	-418359	202485	-215874	21994	0	-193880	-198177	-18291	-6020	-2077
2004	-433294	209714	-223580	17995	0	-205585	-210140	-17632	-5551	-1836
2005	-449115	217371	-231744	13996	0	-217748	-222576	-16978	-5113	-1620
2006	-465858	225475	-240383	9997	0	-230386	-235504	-16331	-4704	-1429
2007	-483559	234042	-249517	5998	0	-243519	-248944	-15693	-4324	-1258
2008	-502256	243091	-259165	1999	0	-257166	-262916	-15067	-3971	-1108
2009	-523987	253609	-270378	0	0	-270378	-276473	-14404	-3611	-971
2010	-548790	265614	-283176	0	0	-283176	-289637	-13718	-3308	-847
2011	-574707	278158	-296549	0	0	-296549	-303398	-13063	-3013	-740
2012	-601778	291260	-310518	0	0	-310518	-317777	-12439	-2744	-646
2013	-630043	304940	-325103	0	0	-325103	-332798	-11842	-2499	-563
2014	-659545	319219	-340326	0	0	-340326	-348483	-11273	-2275	-492
2015	-690325	334117	-356208	0	0	-356208	-192971	-5675	-1096	-227
TOTALS	-12305465	5955831	-6349634	1062183	106218	-5181233	-6227285	-1101670	-664259	-453960

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
200% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) OTHER DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15685	0	0	-15685	0	0	0	0	0	0
1981	-21855	0	0	-21855	0	0	0	0	0	0
1982	-42090	0	0	-42090	0	0	0	0	0	0
1983	-280202	0	0	-280202	0	0	0	0	0	0
1984	-385462	0	0	-385462	0	0	0	0	0	0
1985	-319889	0	-26595	-346484	0	0	0	0	0	0
1986	0	0	-1596	-1596	-308696	-40336	0	-94416	113014	-330434
1987	0	0	-1691	-1691	-327218	-42756	0	-86024	120925	-335073
1988	0	0	-1793	-1793	-346851	-45322	0	-81976	129390	-344759
1989	0	0	-1901	-1901	-367662	-48041	0	-77977	138447	-355233
1990	0	0	-2015	-2015	-389722	-50923	0	-73978	148138	-366485
1991	0	0	-2135	-2135	-413105	-53979	0	-69980	158508	-378555
1992	0	0	-2264	-2264	-437891	-57217	0	-65981	169604	-391486
1993	0	0	-2399	-2399	-464165	-60650	0	-61982	181476	-405321
1994	0	0	-2543	-2543	-492015	-64289	0	-57983	194179	-420108
1995	0	0	-2696	-2696	-521535	-68147	0	-53984	207772	-435895
1996	0	0	-2858	-2858	-552828	-72236	-21304	-49985	222316	-474037
1997	0	0	-3029	-3029	-585997	-76570	-21304	-45987	237878	-491979
1998	0	0	-3211	-3211	-621157	-81164	-21304	-41988	254529	-511083
1999	0	0	-3404	-3404	-658426	-86034	-21304	-37989	272306	-531407
2000	0	0	-3608	-3608	-697932	-91196	-21304	-33990	291410	-553011
2001	0	0	-3824	-3824	-739808	-96668	-21304	-29991	311809	-575961
2002	0	0	-4054	-4054	-784196	-102468	-21304	-25992	333616	-600324
2003	0	0	-4297	-4297	-831248	-108616	-21304	-21994	356990	-626171
2004	0	0	-4555	-4555	-881123	-115133	-21304	-17995	381990	-653574
2005	0	0	-4828	-4828	-933991	-122041	-21304	-13996	408718	-682612
2006	0	0	-5118	-5118	-990030	-129363	-21304	-9997	437329	-713365
2007	0	0	-5425	-5425	-1049432	-137125	-21304	-5998	467942	-745917
2008	0	0	-5750	-5750	-1112398	-145352	-21304	-1999	500697	-780356
2009	0	0	-6095	-6095	-1179142	-154073	-21304	0	535746	-818772
2010	0	0	-6461	-6461	-1249890	-163318	-21304	0	573249	-861263
2011	0	0	-6849	-6849	-1324883	-173117	-21304	0	613376	-905928
2012	0	0	-7259	-7259	-1404376	-183504	-21304	0	656312	-952872
2013	0	0	-7695	-7695	-1488639	-194514	-21304	0	702254	-1002203
2014	0	0	-8157	-8157	-1577957	-206185	-21304	0	751412	-1054034
2015	19135	0	144101	163237	-1672635	-218556	-21304	0	804011	-1108484
TOTALS	-1046047	0	0	-1046051	-24404948	-3188891	-426073	-1062183	10675393	-18406702

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : EASTERN COAL
200X FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48+11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10+1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1268	1267	-14417	-11915	-10901	-10012
1981	0	0	0	0	2186	2185	-19669	-14778	-12933	-11383
1982	0	0	0	0	4209	4208	-37681	-25673	-21659	-18268
1983	0	0	0	0	28020	28019	-252182	-156585	-125379	-101346
1984	0	0	0	0	38546	38545	-346916	-195825	-149981	-116181
1985	0	0	0	0	31989	31988	-314495	-161386	-118230	-87770
1986	-330434	159930	-170504	94416	0	-76088	-77684	-36240	-25395	-18067
1987	-335073	162175	-172898	86024	0	-86874	-88565	-37560	-25176	-17164
1988	-344759	166863	-177896	81976	0	-95920	-97713	-37673	-24153	-15781
1989	-355233	171932	-183301	77977	0	-105324	-107225	-37582	-23007	-14431
1990	-366485	177376	-189107	73978	0	-115129	-117144	-37326	-21895	-13138
1991	-378555	183220	-195335	69980	0	-125355	-127490	-36929	-20721	-11916
1992	-391486	189479	-202007	65981	0	-136026	-138290	-36416	-19544	-10771
1993	-405321	196175	-209146	61982	0	-147164	-149563	-35804	-18380	-9707
1994	-420108	203332	-216776	57983	0	-158793	-161336	-35111	-17241	-8726
1995	-435895	210973	-224922	53984	0	-170938	-173634	-34353	-16135	-7826
1996	-444037	229433	-244604	49985	0	-194619	-197477	-35518	-15967	-7417
1997	-491979	238118	-253861	45987	0	-207874	-210903	-34484	-14819	-6601
1998	-511083	247364	-263719	41988	0	-221731	-224942	-33436	-13744	-5867
1999	-531407	257200	-274207	37989	0	-236218	-239622	-32380	-12731	-5209
2000	-553011	267657	-285354	33990	0	-251364	-254972	-31322	-11780	-4619
2001	-575961	278765	-297196	29991	0	-267205	-271029	-30268	-10888	-4091
2002	-600324	290556	-309768	25992	0	-283776	-287830	-29222	-10055	-3621
2003	-626171	303066	-323105	21994	0	-301111	-305408	-28188	-9278	-3201
2004	-653574	316330	-337244	17995	0	-319249	-323804	-27169	-8553	-2829
2005	-682612	330384	-352228	13996	0	-338232	-343060	-26168	-7880	-2497
2006	-713365	345268	-368097	9997	0	-358100	-363218	-25187	-7255	-2203
2007	-745917	361023	-384894	5998	0	-378894	-384321	-24227	-6675	-1943
2008	-780356	377692	-402664	1999	0	-400665	-406415	-23291	-6138	-1712
2009	-818772	396285	-422487	0	0	-422487	-428582	-22329	-5629	-1505
2010	-861263	416851	-444412	0	0	-444412	-450873	-21354	-5149	-1319
2011	-905928	438469	-467459	0	0	-467459	-474308	-20422	-4710	-1156
2012	-952872	461189	-491683	0	0	-491683	-498942	-19530	-4368	-1014
2013	-1002203	485066	-517137	0	0	-517137	-524832	-18676	-3941	-889
2014	-1054034	510152	-543882	0	0	-543882	-552039	-17858	-3605	-779
2015	-1108484	536506	-571978	0	0	-571978	-408741	-12020	-2321	-481
TOTALS	-18406702	8908831	-9497871	1062183	106218	-8329470	-9375522	-1444390	-816175	-531424

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : WESTERN COAL
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.060)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15754	0	0	-15754	0	0	0	0	0	0
1981	-21977	0	0	-21977	0	0	0	0	0	0
1982	-42326	0	0	-42326	0	0	0	0	0	0
1983	-281773	0	0	-281773	0	0	0	0	0	0
1984	-387654	0	0	-387654	0	0	0	0	0	0
1985	-321661	0	-29220	-350881	0	0	0	0	0	0
1986	0	0	-1753	-1753	-152618	-37537	0	-94946	113014	-172087
1987	0	0	-1858	-1858	-161775	-39789	0	-86507	120925	-167146
1988	0	0	-1970	-1970	-171482	-42177	0	-82436	129390	-166705
1989	0	0	-2088	-2088	-181770	-44707	0	-78415	138447	-166446
1990	0	0	-2213	-2213	-192677	-47390	0	-74394	148138	-166322
1991	0	0	-2346	-2346	-204237	-50233	0	-70372	158508	-166335
1992	0	0	-2487	-2487	-216492	-53247	0	-66351	169604	-166486
1993	0	0	-2636	-2636	-229481	-56442	0	-62330	181476	-166777
1994	0	0	-2794	-2794	-243250	-59828	0	-58309	194179	-167208
1995	0	0	-2962	-2962	-257845	-63418	0	-54287	207772	-167779
1996	0	0	-3140	-3140	-273316	-67223	-21423	-50266	222316	-189912
1997	0	0	-3328	-3328	-289715	-71256	-21423	-46245	237878	-190761
1998	0	0	-3528	-3528	-307097	-75532	-21423	-42223	254529	-191746
1999	0	0	-3739	-3739	-325523	-80064	-21423	-38202	272346	-192866
2000	0	0	-3964	-3964	-345055	-84868	-21423	-34181	291410	-194115
2001	0	0	-4202	-4202	-365758	-89960	-21423	-30160	311809	-195491
2002	0	0	-4454	-4454	-387703	-95357	-21423	-26138	333616	-196986
2003	0	0	-4721	-4721	-410966	-101079	-21423	-22117	356990	-198594
2004	0	0	-5004	-5004	-435624	-107143	-21423	-18096	381980	-200306
2005	0	0	-5304	-5304	-461761	-113572	-21423	-14074	408718	-202112
2006	0	0	-5623	-5623	-489467	-120386	-21423	-10053	437329	-204000
2007	0	0	-5960	-5960	-518835	-127609	-21423	-6032	467942	-205957
2008	0	0	-6318	-6318	-549965	-135266	-21423	-2011	500697	-207967
2009	0	0	-6697	-6697	-582963	-143382	-21423	0	535746	-212021
2010	0	0	-7099	-7099	-617940	-151985	-21423	0	573249	-218100
2011	0	0	-7525	-7525	-655017	-161104	-21423	0	613376	-224168
2012	0	0	-7976	-7976	-694318	-170770	-21423	0	656312	-230199
2013	0	0	-8455	-8455	-735977	-181016	-21423	0	702254	-236162
2014	0	0	-8962	-8962	-780135	-191877	-21423	0	751412	-242024
2015	19135	0	158324	177461	-826944	-203390	-21423	0	804011	-247746
TOTALS	-1052009	0	0	-1052010	-12065703	-2967607	-428458	-1068145	10675393	-5854521

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : WESTERN COAL
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.45*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1274	1273	-14480	-11967	-10909	-10056
1981	0	0	0	0	2198	2197	-19779	-14860	-13005	-11446
1982	0	0	0	0	4233	4232	-38093	-26018	-21740	-18370
1983	0	0	0	0	28177	28176	-253596	-157463	-126042	-101915
1984	0	0	0	0	38765	38764	-348849	-196939	-150814	-116842
1985	0	0	0	0	32166	32165	-318715	-163551	-119817	-88948
1986	-172087	83290	-88797	94946	0	6148	4395	2049	1436	1021
1987	-167146	80898	-86248	84507	0	258	-1599	-678	-455	-310
1988	-166705	80685	-86020	82436	0	-3584	-5554	-2141	-1373	-897
1989	-166446	80559	-85887	78415	0	-7472	-9560	-3351	-2055	-1287
1990	-166322	80499	-85823	74394	0	-11429	-13642	-4347	-2560	-1530
1991	-166335	80505	-85830	70372	0	-15458	-17804	-5157	-2894	-1664
1992	-166486	80579	-85907	66351	0	-19556	-22043	-5805	-3115	-1717
1993	-166777	80720	-86057	62330	0	-23727	-26363	-6311	-3240	-1711
1994	-167204	80928	-86280	58309	0	-27971	-30765	-6695	-3248	-1664
1995	-167779	81204	-86575	54287	0	-32288	-35250	-6974	-3276	-1589
1996	-189912	91917	-97995	50266	0	-47729	-50869	-9149	-4110	-1911
1997	-190761	92328	-98433	46245	0	-52188	-55516	-9077	-3901	-1738
1998	-191746	92805	-98941	42223	0	-56718	-60246	-8955	-3681	-1571
1999	-192866	93347	-99519	38202	0	-61317	-65056	-8791	-3456	-1414
2000	-194115	93951	-100164	34181	0	-65983	-69947	-8593	-3232	-1267
2001	-195491	94617	-100874	30160	0	-70714	-74916	-8366	-3010	-1131
2002	-196986	95341	-101645	26138	0	-75507	-79961	-8118	-2743	-1006
2003	-198594	96119	-102475	22117	0	-80358	-85079	-7852	-2544	-892
2004	-200306	96948	-103358	18096	0	-85262	-90266	-7574	-2384	-789
2005	-202112	97822	-104290	14074	0	-90216	-95520	-7286	-2194	-695
2006	-204000	98736	-105264	10053	0	-95211	-100834	-6992	-2014	-612
2007	-205957	99683	-106274	6032	0	-100242	-106202	-6695	-1845	-537
2008	-207967	100655	-107312	2011	0	-105301	-111619	-6397	-1686	-470
2009	-212021	102618	-109403	0	0	-109403	-116100	-6049	-1525	-408
2010	-218100	105560	-112540	0	0	-112540	-119639	-5666	-1366	-350
2011	-224168	108497	-115671	0	0	-115671	-123196	-5304	-1223	-300
2012	-230199	111416	-118783	0	0	-118783	-126759	-4962	-1095	-258
2013	-236162	114302	-121860	0	0	-121860	-130315	-4637	-979	-221
2014	-242024	117139	-124885	0	0	-124885	-133847	-4330	-874	-189
2015	-247746	119908	-127838	0	0	-127838	-49622	1458	281	57
TOTALS	-5854521	2833576	-3020948	1068145	106813	-1845990	-2898002	-743527	-506926	-374604

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : WESTERN COAL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.060)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15754	0	0	-15754	0	0	0	0	0	0
1981	-21977	0	0	-21977	0	0	0	0	0	0
1982	-42326	0	0	-42326	0	0	0	0	0	0
1983	-281773	0	0	-281773	0	0	0	0	0	0
1984	-387654	0	0	-387654	0	0	0	0	0	0
1985	-321661	0	-29220	-350881	0	0	0	0	0	0
1986	0	0	-1753	-1753	-169576	-37537	0	-94946	113014	-189045
1987	0	0	-1858	-1858	-179751	-39789	0	-86507	120925	-185121
1988	0	0	-1970	-1970	-190536	-42177	0	-82436	129390	-185759
1989	0	0	-2088	-2088	-201968	-44707	0	-78415	138447	-186643
1990	0	0	-2213	-2213	-214086	-47390	0	-74394	148118	-187731
1991	0	0	-2346	-2346	-226931	-50233	0	-70372	158508	-189028
1992	0	0	-2487	-2487	-240547	-53247	0	-66351	169604	-190541
1993	0	0	-2636	-2636	-254980	-56442	0	-62330	181476	-192275
1994	0	0	-2794	-2794	-270278	-59828	0	-58309	194179	-194236
1995	0	0	-2962	-2962	-286495	-63418	0	-54287	207772	-196429
1996	0	0	-3140	-3140	-303685	-67223	-21423	-50266	222316	-220281
1997	0	0	-3328	-3328	-321906	-71256	-21423	-46245	237878	-222952
1998	0	0	-3528	-3528	-341220	-75532	-21423	-42223	254529	-225869
1999	0	0	-3739	-3739	-361693	-80064	-21423	-38202	272306	-229036
2000	0	0	-3964	-3964	-383395	-84868	-21423	-34181	291410	-232456
2001	0	0	-4202	-4202	-406399	-89960	-21423	-30160	311809	-236132
2002	0	0	-4454	-4454	-430783	-95357	-21423	-26138	333636	-240065
2003	0	0	-4721	-4721	-456630	-101079	-21423	-22117	356990	-244258
2004	0	0	-5004	-5004	-484027	-107143	-21423	-18696	381980	-248710
2005	0	0	-5304	-5304	-513069	-113572	-21423	-14074	408718	-253420
2006	0	0	-5623	-5623	-543853	-120386	-21423	-10053	437329	-258387
2007	0	0	-5960	-5960	-576484	-127609	-21423	-6032	467942	-263607
2008	0	0	-6318	-6318	-611074	-135266	-21423	-2011	500697	-269076
2009	0	0	-6697	-6697	-647738	-143382	-21423	0	535746	-276796
2010	0	0	-7099	-7099	-686602	-151985	-21423	0	573249	-286761
2011	0	0	-7525	-7525	-727798	-161104	-21423	0	613376	-296949
2012	0	0	-7976	-7976	-771466	-170770	-21423	0	656312	-307347
2013	0	0	-8455	-8455	-817754	-181016	-21423	0	702254	-317939
2014	0	0	-8962	-8962	-866819	-191877	-21423	0	751412	-328708
2015	19135	0	158324	177461	-918829	-203390	-21423	0	804011	-339631
TOTALS	-1052009	0	0	-1052010	-13406372	-2967607	-428458	-1068145	10675393	-7195189

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : WESTERN COAL
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1274	1274	-14480	-11967	-10949	-10056
1981	0	0	0	0	2198	2197	-19779	-14860	-13005	-11446
1982	0	0	0	0	4233	4232	-38093	-26018	-21740	-18370
1983	0	0	0	0	28177	28176	-253596	-157463	-126042	-101915
1984	0	0	0	0	38765	38764	-348889	-196939	-150814	-116842
1985	0	0	0	0	32166	32165	-318715	-163551	-119817	-88948
1986	-189045	91497	-97548	94946	0	-2602	-4355	-2032	-1424	-1013
1987	-185121	89598	-95523	86507	0	-9016	-10874	-4612	-3091	-2107
1988	-185759	89907	-95852	82436	0	-13416	-15386	-5932	-3803	-2485
1989	-186643	90335	-96308	78415	0	-17893	-19981	-7003	-4295	-2689
1990	-187731	90861	-96670	74394	0	-22476	-24689	-7867	-4615	-2769
1991	-189028	91489	-97539	70372	0	-27167	-29513	-8549	-4797	-2758
1992	-190541	92222	-98319	66351	0	-31968	-34455	-9073	-4869	-2694
1993	-192275	93061	-99214	62330	0	-36884	-39520	-9461	-4857	-2565
1994	-194236	94010	-100226	58309	0	-41917	-44711	-9730	-4778	-2418
1995	-196429	95071	-101358	54287	0	-47071	-50033	-9899	-4649	-2255
1996	-220281	106616	-113665	50266	0	-63399	-66539	-11968	-5377	-2499
1997	-222952	107908	-115044	46245	0	-68799	-72127	-11793	-5068	-2258
1998	-225869	109320	-116549	42223	0	-74326	-77854	-11573	-4757	-2031
1999	-229036	110853	-118183	38202	0	-79981	-83720	-11313	-4448	-1820
2000	-232456	112508	-119948	34181	0	-85767	-89731	-11023	-4146	-1625
2001	-236132	114287	-121845	30160	0	-91685	-95887	-10708	-3852	-1447
2002	-240065	116191	-123874	26138	0	-97736	-102190	-10375	-3570	-1285
2003	-244258	118220	-126038	22117	0	-103921	-108642	-10027	-3300	-1139
2004	-248710	120375	-128335	18096	0	-110239	-115243	-9670	-3044	-1007
2005	-253420	122655	-130765	14074	0	-116691	-121995	-9305	-2802	-888
2006	-258387	125059	-133328	10053	0	-123275	-128898	-8938	-2575	-782
2007	-263607	127585	-136022	6032	0	-129990	-135950	-8570	-2361	-687
2008	-269076	130232	-138844	2011	0	-136833	-143151	-8204	-2162	-603
2009	-275796	133969	-142827	0	0	-142827	-149524	-7790	-1964	-525
2010	-286761	138792	-147969	0	0	-147969	-155068	-7344	-1771	-454
2011	-296949	143723	-153226	0	0	-153226	-160751	-6921	-1596	-392
2012	-307347	148755	-158592	0	0	-158592	-166568	-6520	-1498	-338
2013	-317939	153882	-164057	0	0	-164057	-172512	-6139	-1205	-292
2014	-328708	159094	-169614	0	0	-169614	-178576	-5777	-1166	-252
2015	-339631	164381	-175250	0	0	-175250	2210	64	12	2
TOTALS	-7195189	3482456	-3712732	1068145	106813	-2537774	-3589785	-818832	-540309	-391625

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : WESTERN COAL
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15754	0	0	-15754	0	0	0	0	0	0
1981	-21977	0	0	-21977	0	0	0	0	0	0
1982	-42326	0	0	-42326	0	0	0	0	0	0
1983	-281773	0	0	-281773	0	0	0	0	0	0
1984	-387654	0	0	-387654	0	0	0	0	0	0
1985	-321661	0	-29220	-350881	0	0	0	0	0	0
1986	0	0	-1753	-1753	-254364	-37537	0	-94946	113014	-273833
1987	0	0	-1858	-1858	-269626	-39789	0	-86507	120925	-274997
1988	0	0	-1970	-1970	-285803	-42177	0	-82436	129390	-281026
1989	0	0	-2088	-2088	-302952	-44707	0	-78415	138447	-287627
1990	0	0	-2213	-2213	-321129	-47390	0	-74394	148138	-294774
1991	0	0	-2346	-2346	-340396	-50233	0	-70372	158508	-302494
1992	0	0	-2487	-2487	-360820	-53247	0	-66351	169604	-310815
1993	0	0	-2636	-2636	-382469	-56442	0	-62330	181476	-319765
1994	0	0	-2794	-2794	-405418	-59828	0	-58309	194179	-329375
1995	0	0	-2962	-2962	-429743	-63418	0	-54287	207772	-339676
1996	0	0	-3140	-3140	-455527	-67223	-21423	-50266	222316	-372123
1997	0	0	-3328	-3328	-482859	-71256	-21423	-46245	237878	-383905
1998	0	0	-3528	-3528	-511830	-75532	-21423	-42223	254529	-396479
1999	0	0	-3739	-3739	-542540	-80064	-21423	-38202	272346	-409883
2000	0	0	-3964	-3964	-575093	-84868	-21423	-34181	291410	-424153
2001	0	0	-4202	-4202	-609598	-89960	-21423	-30160	311809	-439331
2002	0	0	-4454	-4454	-646174	-95357	-21423	-26138	333636	-455457
2003	0	0	-4721	-4721	-684944	-101079	-21423	-22117	356990	-472573
2004	0	0	-5004	-5004	-726041	-107143	-21423	-18096	381980	-490723
2005	0	0	-5304	-5304	-769604	-113572	-21423	-14074	408718	-509955
2006	0	0	-5623	-5623	-815780	-120386	-21423	-10053	437329	-530314
2007	0	0	-5960	-5960	-864727	-127609	-21423	-6032	467942	-551849
2008	0	0	-6318	-6318	-916610	-135266	-21423	-2011	500697	-574612
2009	0	0	-6697	-6697	-971607	-143382	-21423	0	535746	-600665
2010	0	0	-7099	-7099	-1029903	-151985	-21423	0	573249	-630062
2011	0	0	-7525	-7525	-1091697	-161104	-21423	0	613376	-660848
2012	0	0	-7976	-7976	-1157199	-170770	-21423	0	656312	-693080
2013	0	0	-8455	-8455	-1226631	-181016	-21423	0	702254	-726816
2014	0	0	-8962	-8962	-1300229	-191877	-21423	0	751412	-762117
2015	19135	0	158324	177461	-1378243	-203390	-21423	0	804011	-799045
TOTALS	-1052009	0	0	-1052010	-20109558	-2967607	-428458	-1068145	10675393	-13898375

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : WESTERN COAL
150X FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48+11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10+1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1274	1273	-14480	-11967	-10949	-10056
1981	0	0	0	0	2198	2197	-14860	-13005	-11446	-10446
1982	0	0	0	0	4233	4232	-38093	-26018	-21740	-18370
1983	0	0	0	0	28177	28176	-253596	-157463	-126082	-101915
1984	0	0	0	0	38765	38764	-348889	-196939	-150834	-116842
1985	0	0	0	0	32166	32165	-318715	-163531	-119817	-88948
1986	-273833	132535	-141298	94946	0	-46352	-48105	-22441	-15726	-11188
1987	-274997	133098	-141899	86507	0	-55392	-57250	-24280	-16274	-11095
1988	-281026	136016	-145010	82436	0	-62574	-64544	-24885	-15964	-10424
1989	-287627	139211	-148416	78415	0	-70001	-72089	-25267	-15465	-9702
1990	-294774	142670	-152104	74394	0	-77710	-79923	-25466	-14938	-8964
1991	-302494	146407	-156087	70372	0	-85715	-88061	-25508	-14312	-8231
1992	-310815	150434	-160381	66351	0	-94030	-96517	-25416	-13641	-7517
1993	-319765	154766	-164999	62330	0	-102669	-105305	-25209	-12941	-6835
1994	-329375	159417	-169958	58309	0	-111649	-114443	-24906	-12230	-6190
1995	-339676	164403	-175273	54287	0	-120986	-123948	-24522	-11518	-5587
1996	-372123	180107	-192016	50266	0	-141750	-144890	-26060	-11768	-5442
1997	-383905	185810	-198095	46245	0	-151850	-155178	-25373	-10904	-4857
1998	-396479	191895	-204584	42223	0	-162361	-165889	-24658	-10136	-4327
1999	-409883	198383	-211500	38202	0	-173298	-177037	-23923	-9406	-3848
2000	-424153	205290	-218863	34181	0	-184682	-188646	-23174	-8716	-3417
2001	-439331	212636	-226695	30160	0	-196535	-200737	-22418	-8064	-3030
2002	-455457	220440	-235017	26138	0	-208879	-213333	-21659	-7463	-2684
2003	-472573	228725	-243848	22117	0	-221731	-226452	-20901	-6879	-2374
2004	-490723	237510	-253213	18096	0	-235117	-240121	-20147	-6343	-2098
2005	-509955	246818	-263137	14074	0	-249063	-254367	-19403	-5843	-1852
2006	-530314	256671	-273643	10053	0	-263590	-269213	-18668	-5377	-1633
2007	-551849	267095	-284754	6032	0	-278722	-284682	-17946	-4945	-1439
2008	-574612	278112	-296500	2011	0	-294489	-300807	-17239	-4543	-1267
2009	-600665	290722	-309943	0	0	-309943	-316640	-16497	-4158	-1112
2010	-630062	304950	-325112	0	0	-325112	-332211	-15734	-3764	-972
2011	-660848	319850	-340998	0	0	-340998	-348523	-15006	-3461	-850
2012	-693080	335450	-357630	0	0	-357630	-365606	-14311	-3157	-743
2013	-726816	351779	-375037	0	0	-375037	-383492	-13646	-2880	-649
2014	-762117	368864	-393253	0	0	-393253	-402215	-13011	-2626	-567
2015	-799045	386737	-412308	0	0	-412308	-423487	-6906	-1333	-276
TOTALS	-13898375	6726801	-7171571	1068145	106813	-5996613	-7048623	-1195362	-707265	-476730

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : WESTERN COAL
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-15754	0	0	-15754	0	0	0	0	0	0
1981	-21977	0	0	-21977	0	0	0	0	0	0
1982	-42326	0	0	-42326	0	0	0	0	0	0
1983	-281773	0	0	-281773	0	0	0	0	0	0
1984	-387654	0	0	-387654	0	0	0	0	0	0
1985	-321661	0	-29220	-350881	0	0	0	0	0	0
1986	0	0	-1753	-1753	-339152	-37537	0	-94946	113014	-358621
1987	0	0	-1858	-1858	-359501	-39789	0	-86507	120925	-364872
1988	0	0	-1970	-1970	-381071	-42177	0	-82436	129390	-376294
1989	0	0	-2088	-2088	-403935	-44707	0	-78415	138447	-388611
1990	0	0	-2213	-2213	-428172	-47390	0	-74394	148138	-401817
1991	0	0	-2346	-2346	-453862	-50233	0	-70372	158508	-415959
1992	0	0	-2487	-2487	-481094	-53247	0	-66351	169604	-431088
1993	0	0	-2636	-2636	-509959	-56442	0	-62330	181476	-447255
1994	0	0	-2794	-2794	-540557	-59828	0	-58309	194179	-464515
1995	0	0	-2962	-2962	-572990	-63418	0	-54287	207772	-482924
1996	0	0	-3140	-3140	-607370	-67223	-21423	-50266	222316	-523966
1997	0	0	-3328	-3328	-643812	-71256	-21423	-46245	237878	-544858
1998	0	0	-3528	-3528	-682440	-75532	-21423	-42223	254529	-567089
1999	0	0	-3739	-3739	-723387	-80064	-21423	-38202	272346	-590729
2000	0	0	-3964	-3964	-766790	-84868	-21423	-34181	291410	-615851
2001	0	0	-4202	-4202	-812798	-89960	-21423	-30160	311809	-642530
2002	0	0	-4454	-4454	-861565	-95357	-21423	-26138	333636	-670848
2003	0	0	-4721	-4721	-913259	-101079	-21423	-22117	356990	-700888
2004	0	0	-5004	-5004	-968055	-107143	-21423	-18096	381980	-732737
2005	0	0	-5304	-5304	-1026138	-113572	-21423	-14074	408718	-766489
2006	0	0	-5623	-5623	-1087706	-120386	-21423	-10053	437329	-802240
2007	0	0	-5960	-5960	-1152969	-127609	-21423	-6032	467942	-840092
2008	0	0	-6318	-6318	-1222147	-135266	-21423	-2011	500697	-880149
2009	0	0	-6697	-6697	-1295476	-143382	-21423	0	535746	-924534
2010	0	0	-7099	-7099	-1373204	-151985	-21423	0	573249	-973364
2011	0	0	-7525	-7525	-1455597	-161104	-21423	0	613376	-1024748
2012	0	0	-7976	-7976	-1542932	-170770	-21423	0	656312	-1078813
2013	0	0	-8455	-8455	-1635508	-181016	-21423	0	702254	-1135694
2014	0	0	-8962	-8962	-1733639	-191877	-21423	0	751412	-1195527
2015	19135	0	158324	177461	-1837657	-203390	-21423	0	804011	-1258459
TOTALS	-1052009	0	0	-1052010	-26812744	-2967607	-428458	-1068145	10675393	-20601561

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE 1: WESTERN COAL
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	1274	1273	-14480	-11967	-10989	-10056
1981	0	0	0	0	2198	2197	-14860	-13065	-11446	-10370
1982	0	0	0	0	4233	4232	-38093	-26018	-21780	-18370
1983	0	0	0	0	28177	28176	-253596	-157463	-126082	-101915
1984	0	0	0	0	38765	38764	-348889	-196939	-150814	-116842
1985	0	0	0	0	32166	32165	-318715	-163551	-119817	-88948
1986	-358621	173572	-185049	94946	0	-90103	-91856	-42852	-30028	-21363
1987	-364872	176598	-188274	86507	0	-101767	-103625	-43947	-29457	-20083
1988	-376294	182126	-194168	82436	0	-111732	-113702	-43837	-28185	-18364
1989	-388611	188087	-200524	78415	0	-122109	-124197	-43530	-26695	-16715
1990	-401817	194479	-207338	74394	0	-132944	-135157	-43065	-25262	-15159
1991	-415959	201324	-214635	70372	0	-144263	-146609	-42467	-23828	-13703
1992	-431088	208646	-222442	66351	0	-156091	-158578	-41759	-22412	-12351
1993	-447255	216471	-230784	62330	0	-168454	-171090	-40958	-21026	-11105
1994	-464515	224825	-239690	58309	0	-181381	-184175	-40082	-19682	-9962
1995	-482924	233735	-249189	54287	0	-194902	-197864	-39146	-18387	-8918
1996	-523966	253599	-270367	50266	0	-220101	-223241	-40152	-18039	-8385
1997	-544858	263711	-281147	46245	0	-234902	-238230	-38953	-16739	-7457
1998	-567089	274471	-292618	42223	0	-250395	-253923	-37744	-15515	-6623
1999	-590729	285913	-304816	38202	0	-266614	-270353	-36533	-14364	-5877
2000	-615851	298071	-317780	34181	0	-283599	-287563	-35326	-13286	-5209
2001	-642530	310984	-331546	30160	0	-301386	-305588	-34128	-12277	-4613
2002	-670844	324690	-346158	26138	0	-320020	-324474	-32942	-11335	-4082
2003	-700888	339229	-361659	22117	0	-339542	-344263	-31774	-10488	-3609
2004	-732737	354644	-378093	18096	0	-359997	-365001	-30626	-9642	-3188
2005	-766489	370980	-395509	14074	0	-381435	-386739	-29500	-8883	-2815
2006	-802240	388284	-413956	10053	0	-403903	-409526	-28398	-8180	-2484
2007	-840092	406604	-433488	6032	0	-427456	-433416	-27322	-7528	-2191
2008	-880149	425992	-454157	2011	0	-452146	-458464	-26274	-6924	-1931
2009	-924534	447474	-477060	0	0	-477060	-483757	-25203	-6353	-1698
2010	-973364	471107	-502257	0	0	-502257	-509356	-24124	-5817	-1490
2011	-1024748	495977	-528771	0	0	-528771	-536296	-23091	-5326	-1307
2012	-1078813	522145	-556668	0	0	-556668	-564644	-22102	-4876	-1147
2013	-1135644	549675	-586019	0	0	-586019	-594074	-21154	-4464	-1006
2014	-1195527	578635	-616892	0	0	-616892	-625854	-20246	-4086	-883
2015	-1258459	609094	-649365	0	0	-649365	-671904	-13878	-2679	-555
TOTALS	-20601561	9971142	-10630419	1068145	106813	-9455461	-10507471	-1571892	-874180	-561833

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : NO. 6 FUEL OIL
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.070)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-34852	0	0	-34852	0	0	0	0	0	0
1982	-66706	0	0	-66706	0	0	0	0	0	0
1983	-249837	0	0	-249837	0	0	0	0	0	0
1984	-324608	0	0	-324608	0	0	0	0	0	0
1985	-270417	0	-51630	-322047	0	0	0	0	0	0
1986	0	0	-3098	-3098	-269676	-32022	0	-83860	118629	-266929
1987	0	0	-3284	-3284	-288553	-33943	0	-76405	126933	-271969
1988	0	0	-3481	-3481	-308752	-35980	0	-72810	135818	-281724
1989	0	0	-3690	-3690	-330365	-38139	0	-69259	145326	-292436
1990	0	0	-3911	-3911	-353490	-40427	0	-65707	155498	-304126
1991	0	0	-4146	-4146	-378235	-42853	0	-62155	166323	-316859
1992	0	0	-4394	-4394	-404711	-45424	0	-58603	178030	-330708
1993	0	0	-4658	-4658	-433041	-48149	0	-55052	190492	-345749
1994	0	0	-4937	-4937	-463354	-51038	0	-51500	203827	-362065
1995	0	0	-5234	-5234	-495788	-54100	0	-47948	218095	-379743
1996	0	0	-5548	-5548	-530494	-57347	-18928	-44397	233361	-417804
1997	0	0	-5881	-5881	-567628	-60787	-18928	-40845	249697	-438492
1998	0	0	-6233	-6233	-607362	-64435	-18928	-37293	267175	-460843
1999	0	0	-6607	-6607	-649877	-68301	-18928	-33741	285878	-484970
2000	0	0	-7004	-7004	-695369	-72399	-18928	-30190	305889	-510997
2001	0	0	-7424	-7424	-744045	-76743	-18928	-26638	327301	-539052
2002	0	0	-7870	-7870	-796128	-81347	-18928	-23086	350212	-569277
2003	0	0	-8342	-8342	-851857	-86228	-18928	-19534	374727	-601820
2004	0	0	-8842	-8842	-911487	-91402	-18928	-15983	400958	-636841
2005	0	0	-9373	-9373	-975291	-96886	-18928	-12431	429025	-674511
2006	0	0	-9935	-9935	-1043561	-102699	-18928	-8879	459057	-715011
2007	0	0	-10531	-10531	-1116610	-108861	-18928	-5328	491191	-758536
2008	0	0	-11163	-11163	-1194773	-115392	-18928	-1776	525574	-805296
2009	0	0	-11833	-11833	-1278407	-122316	-18928	0	562364	-857287
2010	0	0	-12543	-12543	-1367896	-129655	-18928	0	601730	-914749
2011	0	0	-13295	-13295	-1463649	-137434	-18928	0	643851	-976160
2012	0	0	-14093	-14093	-1566104	-145680	-18928	0	688921	-1041792
2013	0	0	-14939	-14939	-1675731	-154421	-18928	0	737185	-1111936
2014	0	0	-15835	-15835	-1793032	-163686	-18928	0	788705	-1186902
2015	17978	0	279750	297730	-1918545	-173508	-18928	0	843967	-1267023
TOTALS	-928441	0	0	-928444	-25473810	-2531601	-378568	-943420	11205791	-18121609

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PROJECT COST ANALYSIS
 BASED ON PRESENT WORTH
 OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
 CASE : NO. 6 FUEL OIL
 90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	3184	3183	-31668	-23793	-20822	-18326
1982	0	0	0	0	6671	6670	-60035	-41005	-34325	-28952
1983	0	0	0	0	24984	24983	-224853	-139616	-111742	-90363
1984	0	0	0	0	32461	32460	-292147	-164909	-126363	-97839
1985	0	0	0	0	27042	27041	-295005	-151384	-110963	-82330
1986	-266929	129193	-137736	83860	0	-53876	-56974	-26579	-18625	-13250
1987	-271969	131632	-140337	76405	0	-63932	-67216	-28506	-19167	-13027
1988	-281724	136354	-145370	72810	0	-72560	-76041	-29317	-18766	-12281
1989	-292436	141539	-150897	69259	0	-81638	-85328	-29907	-18341	-11484
1990	-304126	147196	-156930	65707	0	-91223	-95134	-30313	-17781	-10670
1991	-316859	153359	-163500	62155	0	-101345	-105491	-30557	-17145	-9860
1992	-330708	160062	-170646	58603	0	-112043	-116437	-30662	-16466	-9069
1993	-345749	167342	-178407	55052	0	-123355	-128013	-30645	-15732	-8309
1994	-362065	175239	-186826	51500	0	-135326	-140263	-30525	-14989	-7587
1995	-379743	183795	-195948	47948	0	-148000	-153234	-30317	-14239	-6907
1996	-417804	202217	-215587	44397	0	-171190	-176738	-31788	-14281	-6638
1997	-438492	212230	-226262	40845	0	-185417	-191298	-31279	-13442	-5988
1998	-460843	223047	-237796	37293	0	-200503	-206736	-30730	-12632	-5393
1999	-484490	234725	-250245	33741	0	-216504	-223111	-30149	-11864	-4850
2000	-510997	247322	-263675	30190	0	-233485	-240489	-29543	-11111	-4356
2001	-539052	260901	-278151	26638	0	-251513	-258937	-28918	-10463	-3909
2002	-569277	275530	-293747	23086	0	-270661	-278531	-28278	-9730	-3504
2003	-601820	291281	-310539	19534	0	-291005	-299347	-27629	-9093	-3138
2004	-636841	308231	-328610	15983	0	-312627	-321469	-26973	-8492	-2808
2005	-674511	326463	-348048	12431	0	-335617	-344990	-26315	-7974	-2511
2006	-715011	346065	-368946	8879	0	-360067	-370002	-25657	-7360	-2245
2007	-758536	367131	-391405	5328	0	-386077	-396608	-25002	-6888	-2005
2008	-805296	389763	-415533	1776	0	-413757	-424920	-24352	-6418	-1790
2009	-857287	414927	-442360	0	0	-442360	-454193	-23663	-5965	-1594
2010	-914749	442738	-472011	0	0	-472011	-484554	-22950	-5534	-1418
2011	-976160	472461	-503699	0	0	-503699	-516994	-22260	-5134	-1260
2012	-1041792	504227	-537565	0	0	-537565	-551658	-21593	-4764	-1121
2013	-1111936	538176	-573760	0	0	-573760	-588699	-20948	-4420	-997
2014	-1186902	574460	-612442	0	0	-612442	-628277	-20324	-4102	-886
2015	-1267023	613239	-653784	0	0	-653784	-656054	-10471	-2022	-419
TOTALS	-18121609	8770845	-9350762	943420	94342	-8313000	-9241444	-1326839	-736940	-477065

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : NO. 6 FUEL OIL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-34852	0	0	-34852	0	0	0	0	0	0
1982	-66706	0	0	-66706	0	0	0	0	0	0
1983	-249837	0	0	-249837	0	0	0	0	0	0
1984	-324608	0	0	-324608	0	0	0	0	0	0
1985	-270417	0	-51630	-322047	0	0	0	0	0	0
1986	0	0	-3098	-3098	-299640	-32022	0	-83860	118629	-296893
1987	0	0	-3284	-3284	-320615	-33943	0	-76405	126933	-304030
1988	0	0	-3481	-3481	-343058	-35980	0	-72810	135818	-316030
1989	0	0	-3690	-3690	-367072	-38139	0	-69259	145326	-329144
1990	0	0	-3911	-3911	-392767	-40427	0	-65707	155498	-343402
1991	0	0	-4146	-4146	-420261	-42853	0	-62155	166323	-358885
1992	0	0	-4394	-4394	-449679	-45424	0	-58603	178030	-375676
1993	0	0	-4658	-4658	-481156	-48149	0	-55052	190492	-393865
1994	0	0	-4937	-4937	-514837	-51038	0	-51500	203827	-413549
1995	0	0	-5234	-5234	-550876	-54100	0	-47948	218095	-434830
1996	0	0	-5548	-5548	-589437	-57347	-18928	-44397	233361	-476742
1997	0	0	-5881	-5881	-630698	-60787	-18928	-40845	249697	-501562
1998	0	0	-6233	-6233	-674847	-64435	-18928	-37293	267175	-528328
1999	0	0	-6607	-6607	-722086	-68301	-18928	-33741	285878	-557179
2000	0	0	-7004	-7004	-772632	-72399	-18928	-30190	305829	-588260
2001	0	0	-7424	-7424	-826716	-76743	-18928	-26638	327301	-621724
2002	0	0	-7870	-7870	-884586	-81347	-18928	-23086	350212	-657736
2003	0	0	-8342	-8342	-946508	-86228	-18928	-19534	374727	-696471
2004	0	0	-8842	-8842	-1012763	-91402	-18928	-15983	400958	-738118
2005	0	0	-9373	-9373	-1083656	-96886	-18928	-12431	429025	-782877
2006	0	0	-9935	-9935	-1159512	-102699	-18928	-8879	459057	-830962
2007	0	0	-10531	-10531	-1240678	-108861	-18928	-5328	491191	-882604
2008	0	0	-11163	-11163	-1327526	-115392	-18928	-1776	525574	-938048
2009	0	0	-11833	-11833	-1420453	-122316	-18928	0	562364	-999333
2010	0	0	-12543	-12543	-1519884	-129655	-18928	0	601730	-1066738
2011	0	0	-13295	-13295	-1626276	-137434	-18928	0	643851	-1138788
2012	0	0	-14093	-14093	-1740116	-145680	-18928	0	688921	-1215804
2013	0	0	-14939	-14939	-1861924	-154421	-18928	0	737145	-1298128
2014	0	0	-15835	-15835	-1992258	-163686	-18928	0	788745	-1386128
2015	17978	0	279750	297730	-2131716	-173508	-18928	0	843957	-1480195
TOTALS	-928441	0	0	-928444	-28304234	-2531601	-378568	-943420	11205791	-20952033

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : NO. 6 FUEL OIL
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	3184	3184	-31668	-23793	-20822	-18326
1982	0	0	0	0	6671	6670	-60035	-41005	-34325	-28952
1983	0	0	0	0	24984	24983	-224853	-139616	-111792	-90363
1984	0	0	0	0	32461	32460	-292147	-164909	-126363	-97839
1985	0	0	0	0	27042	27041	-295005	-151384	-110903	-82330
1986	-296893	143695	-153198	83860	0	-69338	-72436	-33792	-23679	-16846
1987	-304030	147150	-156880	76405	0	-80475	-83759	-35522	-23810	-16233
1988	-316030	152958	-163072	72810	0	-90262	-93743	-36142	-23172	-15140
1989	-329144	159305	-169839	69259	0	-100580	-104270	-36546	-22412	-14033
1990	-343402	166206	-177196	65707	0	-111489	-115400	-36770	-21569	-12943
1991	-358885	173700	-185185	62155	0	-123030	-127176	-36838	-20670	-11886
1992	-375676	181827	-193849	58603	0	-135246	-139640	-36772	-19735	-10876
1993	-393865	190630	-203235	55052	0	-148183	-152841	-36589	-18783	-9920
1994	-413549	200157	-213392	51500	0	-161892	-166829	-36307	-17828	-9023
1995	-434830	210457	-224373	47948	0	-176425	-181659	-35940	-16881	-8188
1996	-476748	230745	-246003	44397	0	-201606	-207154	-37258	-16739	-7781
1997	-501562	242755	-258807	40845	0	-217962	-223843	-36600	-15728	-7006
1998	-528328	255710	-272618	37293	0	-235325	-241558	-35906	-14759	-6301
1999	-557179	269674	-287505	33741	0	-253764	-260371	-35184	-13834	-5660
2000	-588260	284717	-303543	30190	0	-273353	-280357	-34441	-12953	-5078
2001	-621724	300914	-320810	26638	0	-294172	-301596	-33682	-12116	-4553
2002	-657736	318344	-339392	23086	0	-316306	-324176	-32912	-11325	-4078
2003	-696471	337092	-359379	19534	0	-339845	-348187	-32136	-10577	-3650
2004	-738118	357249	-380869	15983	0	-364886	-373728	-31358	-9872	-3265
2005	-782877	378912	-403965	12431	0	-391534	-400907	-30580	-9209	-2918
2006	-830962	402185	-428777	8879	0	-419898	-429833	-29806	-8585	-2608
2007	-882604	427180	-455424	5328	0	-450096	-460627	-29038	-8000	-2329
2008	-938048	454015	-484033	1776	0	-482257	-493420	-28277	-7452	-2079
2009	-999333	483676	-515657	0	0	-515657	-527490	-27482	-6928	-1852
2010	-1066738	516301	-550437	0	0	-550437	-562980	-26664	-6429	-1647
2011	-1138788	551173	-587615	0	0	-587615	-600910	-25873	-5967	-1465
2012	-1215804	588448	-627356	0	0	-627356	-641449	-25108	-5539	-1303
2013	-1298128	628294	-669834	0	0	-669834	-684773	-24367	-5142	-1159
2014	-1386128	670885	-715243	0	0	-715243	-731078	-23650	-4774	-1031
2015	-1480195	716414	-763781	0	0	-763781	-466051	-13706	-2646	-548
TOTALS	-20952033	10140768	-10811267	943420	94342	-9773505	-10701949	-1475937	-801246	-509194

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : NO. 6 FUEL OIL
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER 0.000)	(3) WORKING CAPITAL-NET (ER 0.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER 0.070)	(6) OTHER OPER EXPENSES (ER 0.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER 0.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-34852	0	0	-34852	0	0	0	0	0	0
1982	-66706	0	0	-66706	0	0	0	0	0	0
1983	-249837	0	0	-249837	0	0	0	0	0	0
1984	-324608	0	0	-324608	0	0	0	0	0	0
1985	-270417	0	-51630	-322047	0	0	0	0	0	0
1986	0	0	-3098	-3098	-449460	-32022	0	-83860	118629	-446713
1987	0	0	-3284	-3284	-480922	-33943	0	-76405	126933	-464338
1988	0	0	-3481	-3481	-514587	-35980	0	-72810	135818	-487559
1989	0	0	-3690	-3690	-550608	-38139	0	-69259	145326	-512680
1990	0	0	-3911	-3911	-589150	-40427	0	-65707	155498	-539786
1991	0	0	-4146	-4146	-630391	-42853	0	-62155	166383	-569015
1992	0	0	-4394	-4394	-674518	-45424	0	-58603	178030	-600515
1993	0	0	-4658	-4658	-721735	-48149	0	-55052	190492	-634443
1994	0	0	-4937	-4937	-772256	-51038	0	-51500	203827	-670967
1995	0	0	-5234	-5234	-826314	-54100	0	-47948	218095	-710268
1996	0	0	-5548	-5548	-884156	-57347	-18928	-44397	233361	-771466
1997	0	0	-5881	-5881	-946047	-60787	-18928	-40845	249697	-816911
1998	0	0	-6233	-6233	-1012270	-64435	-18928	-37293	267175	-865751
1999	0	0	-6607	-6607	-1083129	-68301	-18928	-33741	285878	-918222
2000	0	0	-7004	-7004	-1158948	-72399	-18928	-30190	305829	-974576
2001	0	0	-7424	-7424	-1240074	-76743	-18928	-26638	327361	-1035082
2002	0	0	-7870	-7870	-1326880	-81347	-18928	-23086	350212	-1100029
2003	0	0	-8342	-8342	-1419761	-86228	-18928	-19534	374727	-1169725
2004	0	0	-8842	-8842	-1519145	-91402	-18928	-15983	400958	-1244499
2005	0	0	-9373	-9373	-1625485	-96886	-18928	-12431	429025	-1324705
2006	0	0	-9935	-9935	-1739269	-102699	-18928	-8879	459057	-1410718
2007	0	0	-10531	-10531	-1861017	-108861	-18928	-5328	491191	-1502943
2008	0	0	-11163	-11163	-1991289	-115392	-18928	-1776	525574	-1601811
2009	0	0	-11833	-11833	-2130679	-122316	-18928	0	562364	-1709559
2010	0	0	-12543	-12543	-2279826	-129655	-18928	0	601730	-1826680
2011	0	0	-13295	-13295	-2439414	-137434	-18928	0	643851	-1951926
2012	0	0	-14093	-14093	-2610173	-145680	-18928	0	688921	-2085861
2013	0	0	-14939	-14939	-2792886	-154421	-18928	0	737145	-2229090
2014	0	0	-15835	-15835	-2988388	-163686	-18928	0	788745	-2382257
2015	17978	0	279750	297730	-3197575	-173508	-18928	0	843957	-2546053
TOTALS	-928441	0	0	-928444	-42456352	-2531601	-378568	-943420	11205791	-35104151

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : NO. 6 FUEL OIL
150% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	3184	3183	-31668	-23793	-20822	-18326
1982	0	0	0	0	6671	6670	-60035	-41005	-34325	-28952
1983	0	0	0	0	24984	24983	-224853	-139616	-111792	-90363
1984	0	0	0	0	32461	32460	-292147	-164909	-126303	-97839
1985	0	0	0	0	27042	27041	-295005	-151384	-110903	-82330
1986	-446713	216208	-230505	83860	0	-146645	-149743	-69856	-42951	-34825
1987	-464338	224739	-239599	76405	0	-163194	-166478	-70603	-47323	-32265
1988	-487559	235978	-251581	72810	0	-178771	-182252	-70266	-45050	-29435
1989	-512680	248136	-264544	69259	0	-195285	-198975	-69740	-42748	-26780
1990	-539786	261256	-278530	65707	0	-212823	-216734	-69058	-40509	-24308
1991	-569015	275403	-293612	62155	0	-231457	-235603	-68246	-38292	-22020
1992	-600515	290649	-309866	58603	0	-251263	-255657	-67322	-36132	-19912
1993	-634443	307070	-327373	55052	0	-272321	-276979	-66307	-34039	-17977
1994	-670967	324748	-346219	51500	0	-294719	-299656	-65214	-32023	-16208
1995	-710268	343769	-366499	47948	0	-318551	-323785	-64059	-30088	-14594
1996	-771466	373389	-398077	44397	0	-353680	-359228	-64610	-29027	-13493
1997	-816911	395384	-421527	40845	0	-380682	-386563	-63206	-27162	-12100
1998	-865751	419023	-446728	37293	0	-409435	-415668	-61786	-25397	-10842
1999	-918222	444419	-473803	33741	0	-440062	-446669	-60359	-23732	-9709
2000	-974576	471694	-502882	30190	0	-472692	-479696	-58929	-22162	-8689
2001	-1035082	500979	-534103	26638	0	-507465	-514889	-57502	-20685	-7772
2002	-1100029	532414	-567615	23086	0	-544529	-552399	-56083	-19298	-6949
2003	-1169725	566146	-603579	19534	0	-584045	-592387	-54675	-17995	-6210
2004	-1244499	602337	-642162	15983	0	-626179	-635021	-53282	-15774	-5547
2005	-1324705	641157	-683548	12431	0	-671117	-680490	-51906	-15631	-4954
2006	-1410718	682787	-727931	8879	0	-719052	-728987	-50550	-14561	-4422
2007	-1502943	727424	-775519	5326	0	-770191	-780722	-49216	-13560	-3947
2008	-1601811	775276	-826535	1776	0	-824759	-835922	-47905	-12625	-3522
2009	-1709559	827426	-882133	0	0	-882133	-893966	-46574	-11741	-3138
2010	-1826680	884113	-942567	0	0	-942567	-955110	-45236	-10907	-2794
2011	-1951926	944732	-1007194	0	0	-1007194	-1020489	-43939	-10134	-2488
2012	-2085861	1009556	-1076305	0	0	-1076305	-1090398	-42681	-9416	-2215
2013	-2229090	1078879	-1150211	0	0	-1150211	-1165150	-41461	-8749	-1973
2014	-2382257	1153012	-1229245	0	0	-1229245	-1245080	-40277	-8130	-1757
2015	-2546053	1232289	-1313764	0	0	-1313764	-1016034	-29880	-5769	-1195
TOTALS	-35104151	16990392	-18113756	943420	94342	-17075994	-18004438	-2221418	-1122758	-669835

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PROJECT COST ANALYSIS
BASED ON PRESENT NORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE 1 NO. 6 FUEL OIL
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-34852	0	0	-34852	0	0	0	0	0	0
1982	-66706	0	0	-66706	0	0	0	0	0	0
1983	-249837	0	0	-249837	0	0	0	0	0	0
1984	-324608	0	0	-324608	0	0	0	0	0	0
1985	-270417	0	-51630	-322047	0	0	0	0	0	0
1986	0	0	-3098	-3098	-599280	-32022	0	-63860	118629	-596533
1987	0	0	-3284	-3284	-641230	-33943	0	-76405	126933	-624645
1988	0	0	-3481	-3481	-686116	-35980	0	-72810	135818	-659088
1989	0	0	-3690	-3690	-734144	-38139	0	-69259	145326	-696215
1990	0	0	-3911	-3911	-785534	-40427	0	-65707	155498	-736169
1991	0	0	-4146	-4146	-840521	-42853	0	-62155	166383	-779146
1992	0	0	-4394	-4394	-899358	-45424	0	-58603	178030	-825355
1993	0	0	-4658	-4658	-962313	-48149	0	-55052	190492	-875021
1994	0	0	-4937	-4937	-1029675	-51038	0	-51500	203827	-928386
1995	0	0	-5234	-5234	-1101752	-54100	0	-47948	218095	-985706
1996	0	0	-5548	-5548	-1178875	-57347	-18928	-44397	233361	-1066185
1997	0	0	-5881	-5881	-1261396	-60787	-18928	-40845	249697	-1132260
1998	0	0	-6233	-6233	-1349694	-64435	-18928	-37293	267175	-1203174
1999	0	0	-6607	-6607	-1444172	-68301	-18928	-33741	285878	-1279265
2000	0	0	-7004	-7004	-1545264	-72399	-18928	-30190	305889	-1360892
2001	0	0	-7424	-7424	-1653433	-76743	-18928	-26638	327361	-1448440
2002	0	0	-7870	-7870	-1769173	-81347	-18928	-23086	350212	-1542322
2003	0	0	-8342	-8342	-1893015	-86228	-18928	-19534	374727	-1642979
2004	0	0	-8842	-8842	-2025526	-91402	-18928	-15983	400958	-1750881
2005	0	0	-9373	-9373	-2167313	-96886	-18928	-12431	429025	-1866533
2006	0	0	-9935	-9935	-2319025	-102699	-18928	-8879	459057	-1990475
2007	0	0	-10531	-10531	-2481357	-108861	-18928	-5328	491191	-2123283
2008	0	0	-11163	-11163	-2655052	-115392	-18928	-1776	525574	-2265574
2009	0	0	-11833	-11833	-2840905	-122316	-18928	0	562364	-2419785
2010	0	0	-12543	-12543	-3039769	-129655	-18928	0	601730	-2586622
2011	0	0	-13295	-13295	-3252552	-137434	-18928	0	643851	-2765064
2012	0	0	-14093	-14093	-3480231	-145680	-18928	0	688921	-2955919
2013	0	0	-14939	-14939	-3723847	-154421	-18928	0	737145	-3160052
2014	0	0	-15835	-15835	-3984517	-163686	-18928	0	788745	-3378386
2015	17978	0	279750	297730	-4263433	-173508	-18928	0	843957	-3611912
TOTALS	-928441	0	0	-928444	-56608469	-2531601	-378568	-943420	11205791	-49256269

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : NO. 6 FUEL OIL
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	3184	3184	-31668	-23793	-20822	-18326
1982	0	0	0	0	6671	6670	-60035	-41005	-34325	-28952
1983	0	0	0	0	24984	24983	-224853	-139616	-111792	-90363
1984	0	0	0	0	32461	32460	-292147	-164909	-126303	-97839
1985	0	0	0	0	27042	27041	-295005	-151384	-110903	-82330
1986	-596533	288721	-307812	83860	0	-223952	-227050	-105921	-70223	-52805
1987	-624645	302328	-322317	76405	0	-245912	-249196	-105683	-70827	-48296
1988	-659088	318998	-340090	72810	0	-267280	-270761	-104390	-66928	-43729
1989	-696215	336968	-359247	69259	0	-289988	-293678	-102932	-63124	-39526
1990	-736169	356305	-379864	65707	0	-314157	-318068	-101346	-55409	-35673
1991	-779146	377106	-402040	62155	0	-339885	-344031	-99654	-55915	-32154
1992	-825355	399471	-425884	58603	0	-367281	-371675	-97874	-52528	-28948
1993	-875021	423510	-451511	55052	0	-396459	-401117	-96024	-49265	-26035
1994	-928386	449338	-479048	51500	0	-427548	-432485	-94121	-46217	-23392
1995	-985706	477081	-508625	47948	0	-460677	-465911	-92178	-43295	-21000
1996	-1066185	516033	-550152	44397	0	-505755	-511303	-91962	-41316	-19205
1997	-1132260	548013	-584247	40845	0	-543402	-549283	-89812	-38566	-17193
1998	-1203174	582336	-620838	37293	0	-583545	-589778	-87667	-36026	-15384
1999	-1279265	619164	-660101	33741	0	-626360	-632967	-85533	-33610	-13759
2000	-1360892	658671	-702221	30190	0	-672031	-679035	-83417	-31372	-12300
2001	-1448440	701045	-747395	26638	0	-720757	-728181	-81322	-29254	-10992
2002	-1542322	746484	-795838	23086	0	-772752	-780622	-79253	-27270	-9820
2003	-1642979	795201	-847778	19534	0	-828244	-836586	-77214	-25414	-8770
2004	-1750881	847426	-903455	15983	0	-887472	-896314	-75206	-23676	-7830
2005	-1866533	903401	-963132	12431	0	-950701	-960074	-73232	-22053	-6989
2006	-1990475	963389	-1027086	8879	0	-1018207	-1028142	-71295	-20536	-6237
2007	-2123283	1027668	-1095615	5328	0	-1090287	-1100818	-69395	-19120	-5565
2008	-2265574	1096537	-1169037	1776	0	-1167261	-1178424	-67534	-17798	-4964
2009	-2419785	1171176	-1248609	0	0	-1248609	-1260442	-65667	-16533	-4025
2010	-2586622	1251925	-1334697	0	0	-1334697	-1347240	-63809	-15366	-3941
2011	-2765064	1338291	-1426773	0	0	-1426773	-1440068	-62005	-14301	-3511
2012	-2955919	1430664	-1525255	0	0	-1525255	-1539348	-60254	-13293	-3127
2013	-3160052	1529465	-1630587	0	0	-1630587	-1645526	-58555	-12326	-2786
2014	-3378396	1635138	-1743248	0	0	-1743248	-1759083	-56905	-11486	-2482
2015	-3611912	1748165	-1863747	0	0	-1863747	-1566017	-46054	-8892	-1841
TOTALS	-49256269	23840018	-25416249	943420	94342	-24378487	-25306931	-2966903	-1440276	-830472

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : HTGR
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-33363	0	0	-33363	0	0	0	0	0	0
1980	-129030	0	0	-129030	0	0	0	0	0	0
1981	-214003	0	0	-214003	0	0	0	0	0	0
1982	-354544	0	0	-354544	0	0	0	0	0	0
1983	-426782	0	0	-426782	0	0	0	0	0	0
1984	-304423	0	0	-304423	0	0	0	0	0	0
1985	-59109	0	0	-59109	0	0	0	0	0	0
1986	0	0	0	0	-61965	-19506	0	-134956	128351	-88076
1987	0	0	0	0	-65001	-20676	0	-122960	137336	-71302
1988	0	0	0	0	-68186	-21917	0	-117174	146949	-60329
1989	0	0	0	0	-71527	-23232	0	-111458	157235	-48982
1990	0	0	0	0	-75032	-24626	0	-105743	168202	-37159
1991	0	0	0	0	-78709	-26103	0	-100027	180019	-24820
1992	0	0	0	0	-82566	-27670	0	-94311	192620	-11926
1993	0	0	0	0	-86611	-29330	0	-88595	206104	1566
1994	0	0	0	0	-90855	-31090	0	-82879	220531	15706
1995	0	0	0	0	-95307	-32955	0	-77164	235968	30541
1996	0	0	0	0	-99977	-34932	-30425	-71448	252486	15702
1997	0	0	0	0	-104876	-37028	-30425	-65732	270160	32097
1998	0	0	0	0	-110015	-39250	-30425	-60016	289071	49364
1999	0	0	0	0	-115406	-41605	-30425	-54300	309306	67569
2000	0	0	0	0	-121061	-44101	-30425	-48584	330957	86785
2001	0	0	0	0	-126993	-46747	-30425	-42869	354124	107090
2002	0	0	0	0	-133215	-49552	-30425	-37153	378913	128567
2003	0	0	0	0	-139743	-52525	-30425	-31437	405437	151306
2004	0	0	0	0	-146590	-55677	-30425	-25721	433818	175403
2005	0	0	0	0	-153773	-59017	-30425	-20005	464185	200963
2006	0	0	0	0	-161308	-62558	-30425	-14290	496678	228096
2007	0	0	0	0	-169212	-66312	-30425	-8574	531445	256921
2008	0	0	0	0	-177504	-70291	-30425	-2858	568647	287568
2009	0	0	0	0	-186201	-74508	-30425	0	608452	317316
2010	0	0	0	0	-195325	-78979	-30425	0	651043	346314
2011	0	0	0	0	-204896	-83717	-30425	0	696617	377577
2012	0	0	0	0	-214936	-88740	-30425	0	745380	411277
2013	0	0	0	0	-225468	-94065	-30425	0	797556	447598
2014	0	0	0	0	-236516	-99709	-30425	0	853385	486735
2015	20373	0	0	20373	-248105	-105691	-30425	0	913122	528900
TOTALS	-1500880	0	0	-1500881	-4046881	-1542109	-608502	-1518254	12124138	4408391

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISHAR COGENERATION
CASE : HTGR
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	3035	3034	-30328	-27571	-26372	-25273
1980	0	0	0	0	12903	12902	-116127	-95973	-87809	-80644
1981	0	0	0	0	21400	21399	-192603	-144705	-126640	-111460
1982	0	0	0	0	35454	35453	-319090	-217943	-182441	-153882
1983	0	0	0	0	42678	42677	-384104	-238498	-190968	-154363
1984	0	0	0	0	30442	30441	-273981	-154655	-118480	-91756
1985	0	0	0	0	5911	5910	-53198	-27299	-19999	-14847
1986	-88076	42628	-45448	134956	0	89507	89507	41755	29289	20815
1987	-71302	34510	-36792	122960	0	86167	86167	36542	24493	16699
1988	-60329	29199	-31130	117174	0	86043	86043	33172	21268	13695
1989	-48982	23707	-25275	111458	0	86182	86182	30205	18523	11598
1990	-37159	17984	-19175	105743	0	86567	86567	27582	16179	9708
1991	-24820	12013	-12807	100027	0	87219	87219	25263	14175	8151
1992	-11926	5772	-6154	94311	0	88156	88156	23213	12458	6865
1993	1566	-758	808	88595	0	89402	89402	21401	10986	5802
1994	15706	-7602	8104	82879	0	90982	90982	19799	9722	4920
1995	30541	-14782	15759	77164	0	92922	92922	18383	8634	4187
1996	15702	-7600	8102	71448	0	79549	79549	14307	6427	2987
1997	32097	-15535	16562	65732	0	82293	82293	13455	5781	2575
1998	49364	-23892	25472	60016	0	85487	85487	12706	5222	2229
1999	67569	-32703	34866	54300	0	89165	89165	12048	4736	1937
2000	86785	-42004	44781	48584	0	93364	93364	11468	4312	1690
2001	107090	-51831	55259	42869	0	98127	98127	10958	3941	1488
2002	128567	-62226	66341	37153	0	103493	103493	10506	3614	1301
2003	151306	-73232	78074	31437	0	109510	109510	10106	3326	1147
2004	175403	-84895	90508	25721	0	116228	116228	9751	3069	1014
2005	206963	-97266	103697	20005	0	123701	123701	9435	2840	899
2006	228096	-110398	117698	14290	0	131987	131987	9151	2635	800
2007	256921	-124350	132571	8574	0	141144	141144	8897	2450	713
2008	287568	-139183	148385	2858	0	151242	151242	8666	2283	636
2009	317316	-153581	163735	0	0	163734	163734	8529	2149	574
2010	346314	-167616	178698	0	0	178697	178697	8463	2040	522
2011	377577	-182747	194830	0	0	194829	194829	8388	1934	474
2012	411277	-199058	212219	0	0	212218	212218	8306	1832	430
2013	447598	-216637	230961	0	0	230960	230960	8218	1733	390
2014	486735	-235580	251155	0	0	251154	251154	8124	1639	353
2015	528900	-255986	272912	0	0	272911	272911	8024	1544	344
TOTALS	4403391	-2133651	2274716	1518254	151823	3944792	2443882	-429173	-523303	-507040

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : HTGR
100% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-33363	0	0	-33363	0	0	0	0	0	0
1980	-129030	0	0	-129030	0	0	0	0	0	0
1981	-214003	0	0	-214003	0	0	0	0	0	0
1982	-354544	0	0	-354544	0	0	0	0	0	0
1983	-426782	0	0	-426782	0	0	0	0	0	0
1984	-304423	0	0	-304423	0	0	0	0	0	0
1985	-59109	0	0	-59109	0	0	0	0	0	0
1986	0	0	0	0	-68850	-19506	0	-134956	128351	-94961
1987	0	0	0	0	-72224	-20676	0	-122960	137316	-78524
1988	0	0	0	0	-75763	-21917	0	-117174	146949	-67905
1989	0	0	0	0	-79475	-23232	0	-111458	157235	-56930
1990	0	0	0	0	-83369	-24626	0	-105743	168242	-45496
1991	0	0	0	0	-87454	-26103	0	-100027	180019	-33566
1992	0	0	0	0	-91740	-27670	0	-94311	192620	-21100
1993	0	0	0	0	-96235	-29330	0	-88595	206164	-8056
1994	0	0	0	0	-100950	-31090	0	-82879	220511	5611
1995	0	0	0	0	-105897	-32955	0	-77164	235968	19952
1996	0	0	0	0	-111086	-34932	-30425	-71448	252486	4594
1997	0	0	0	0	-116529	-37028	-30425	-65732	270160	20445
1998	0	0	0	0	-122239	-39250	-30425	-60016	289071	37140
1999	0	0	0	0	-128229	-41605	-30425	-54300	309306	54746
2000	0	0	0	0	-134512	-44101	-30425	-48584	330957	73334
2001	0	0	0	0	-141103	-46747	-30425	-42869	354124	92979
2002	0	0	0	0	-148017	-49552	-30425	-37153	378913	113765
2003	0	0	0	0	-155270	-52525	-30425	-31437	405417	135779
2004	0	0	0	0	-162878	-55677	-30425	-25721	433818	159116
2005	0	0	0	0	-170859	-59017	-30425	-20005	464185	183877
2006	0	0	0	0	-179231	-62558	-30425	-14290	496678	210173
2007	0	0	0	0	-188014	-66312	-30425	-8574	531445	238120
2008	0	0	0	0	-197226	-70291	-30425	-2858	568647	267846
2009	0	0	0	0	-206890	-74508	-30425	0	608452	296627
2010	0	0	0	0	-217028	-78979	-30425	0	651043	324611
2011	0	0	0	0	-227662	-83717	-30425	0	696617	354811
2012	0	0	0	0	-238818	-88740	-30425	0	745380	387396
2013	0	0	0	0	-250520	-94065	-30425	0	797556	422546
2014	0	0	0	0	-262795	-99709	-30425	0	853385	460455
2015	20373	0	0	20373	-275672	-105691	-30425	0	913122	501333
TOTALS	-1500880	0	0	-1500881	-4496535	-1542109	-608502	-1518254	12124138	3958737

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISHAN COGENERATION
CASE : WTGR
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 F+0)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=,10)	(19) PRESENT WORTH=NCF (DR=,15)	(20) PRESENT WORTH=NCF (DR=,20)
1979	0	0	0	0	3035	3034	-30328	-27571	-26372	-25273
1980	0	0	0	0	12903	12902	-116127	-95973	-87809	-80644
1981	0	0	0	0	21400	21399	-192603	-144705	-126640	-111460
1982	0	0	0	0	35454	35453	-319090	-217943	-182441	-153882
1983	0	0	0	0	42678	42677	-384104	-238498	-190968	-154363
1984	0	0	0	0	30442	30441	-273981	-154655	-118450	-91756
1985	0	0	0	0	5911	5910	-53198	-27299	-19999	-14847
1986	-94961	45961	-49000	134956	0	85955	85955	40098	28098	19989
1987	-78524	38005	-40519	122960	0	82440	82440	34962	23414	15976
1988	-67905	32865	-35040	117174	0	82133	82133	31665	20301	13264
1989	-56930	27554	-29376	111458	0	82081	82081	28768	17602	11046
1990	-45496	22019	-23477	105743	0	82265	82265	26211	15375	9226
1991	-33566	16245	-17321	100027	0	82705	82705	23956	13441	7729
1992	-21100	10212	-10888	94311	0	83422	83422	21967	11789	6496
1993	-8056	3899	-4157	88595	0	84437	84437	20213	10376	5479
1994	5611	-2716	2895	82879	0	85773	85773	18666	9165	4638
1995	19952	-9657	10295	77164	0	87458	87458	17302	8126	3941
1996	4594	-2223	2371	71448	0	73818	73818	13276	5964	2772
1997	20445	-9895	10550	65732	0	76281	76281	12472	5359	2387
1998	37140	-17976	19164	60016	0	79179	79179	11768	4837	2064
1999	54746	-26497	28249	54300	0	82548	82548	11154	4355	1793
2000	73334	-35494	37840	48584	0	86423	86423	10616	3992	1564
2001	92979	-45002	47977	42869	0	90845	90845	10144	3649	1370
2002	113765	-55062	58703	37153	0	95855	95855	9731	3308	1205
2003	135779	-65717	70062	31437	0	101498	101498	9367	3082	1063
2004	159116	-77012	82104	25721	0	107824	107824	9046	2807	941
2005	183877	-88996	94881	20005	0	114885	114885	8762	2638	835
2006	210173	-101724	108449	14290	0	122738	122738	8510	2451	744
2007	236120	-115250	122870	8574	0	131443	131443	8285	2282	663
2008	267846	-129637	138209	2858	0	141066	141066	8083	2130	593
2009	296627	-143568	153059	0	0	153058	153058	7973	2009	536
2010	324611	-157112	167499	0	0	167498	167498	7932	1912	489
2011	354811	-171728	183083	0	0	183082	183082	7882	1817	445
2012	387396	-187499	199897	0	0	199896	199896	7823	1725	405
2013	422546	-204512	218034	0	0	218033	218033	7758	1636	368
2014	460455	-222860	237595	0	0	237594	237594	7685	1550	334
2015	501333	-242645	258688	0	0	258687	258687	7606	1483	327
TOTALS	3958737	-1916022	2042696	1518254	151823	3712772	2211862	-456317	-535690	-513488

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : HTGR
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-33363	0	0	-33363	0	0	0	0	0	0
1980	-129030	0	0	-129030	0	0	0	0	0	0
1981	-214003	0	0	-214003	0	0	0	0	0	0
1982	-354544	0	0	-354544	0	0	0	0	0	0
1983	-426782	0	0	-426782	0	0	0	0	0	0
1984	-304423	0	0	-304423	0	0	0	0	0	0
1985	-59109	0	0	-59109	0	0	0	0	0	0
1986	0	0	0	0	-103275	-19506	0	-134956	128351	-129386
1987	0	0	0	0	-108335	-20676	0	-122960	137336	-114636
1988	0	0	0	0	-113644	-21917	0	-117174	146949	-105786
1989	0	0	0	0	-119212	-23232	0	-111458	157235	-96667
1990	0	0	0	0	-125054	-24626	0	-105743	168242	-87180
1991	0	0	0	0	-131182	-26103	0	-100027	180019	-77293
1992	0	0	0	0	-137609	-27670	0	-94311	192620	-66970
1993	0	0	0	0	-144352	-29330	0	-88595	206104	-56174
1994	0	0	0	0	-151426	-31090	0	-82879	220531	-44864
1995	0	0	0	0	-158845	-32955	0	-77164	235968	-32996
1996	0	0	0	0	-166629	-34932	-30425	-71448	252486	-50948
1997	0	0	0	0	-174794	-37028	-30425	-65732	270160	-37819
1998	0	0	0	0	-183358	-39250	-30425	-60016	289071	-23979
1999	0	0	0	0	-192343	-41605	-30425	-54300	309306	-9367
2000	0	0	0	0	-201768	-44101	-30425	-48584	330957	6078
2001	0	0	0	0	-211654	-46747	-30425	-42869	354124	22428
2002	0	0	0	0	-222026	-49552	-30425	-37153	378913	39757
2003	0	0	0	0	-232905	-52525	-30425	-31437	405437	58144
2004	0	0	0	0	-244317	-55677	-30425	-25721	433818	77677
2005	0	0	0	0	-256289	-59017	-30425	-20005	464185	98447
2006	0	0	0	0	-268847	-62558	-30425	-14290	496678	120557
2007	0	0	0	0	-282020	-66312	-30425	-8574	531445	144113
2008	0	0	0	0	-295839	-70291	-30425	-2858	568647	169233
2009	0	0	0	0	-310335	-74508	-30425	0	608452	193182
2010	0	0	0	0	-325542	-78979	-30425	0	651043	216097
2011	0	0	0	0	-341493	-83717	-30425	0	696617	240980
2012	0	0	0	0	-358227	-88740	-30425	0	745380	267987
2013	0	0	0	0	-375780	-94065	-30425	0	797556	297286
2014	0	0	0	0	-394193	-99709	-30425	0	853385	329058
2015	20373	0	0	20373	-413508	-105691	-30425	0	913122	363497
TOTALS	-1500880	0	0	-1500881	-6744802	-1542109	-608502	-1518254	12124138	1710470

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : HTGR
150X FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	3035	3034	-30328	-27571	-26372	-25273
1980	0	0	0	0	12903	12902	-116127	-95973	-87869	-80644
1981	0	0	0	0	21400	21399	-192603	-144705	-126640	-111460
1982	0	0	0	0	35454	35453	-319090	-217943	-182441	-153882
1983	0	0	0	0	42678	42677	-384104	-238498	-190968	-154363
1984	0	0	0	0	30442	30441	-273981	-154655	-118450	-91756
1985	0	0	0	0	5911	5910	-53198	-27299	-19999	-14847
1986	-129386	62622	-66764	134956	0	68191	68191	31811	22291	15958
1987	-114636	55483	-59153	122960	0	63806	63806	27059	18137	12365
1988	-105786	51200	-54586	117174	0	62587	62587	24129	15470	10107
1989	-96667	46787	-49880	111458	0	61577	61577	21581	13235	8287
1990	-87180	42195	-44985	105743	0	60757	60757	19358	11355	6813
1991	-77293	37409	-39884	100027	0	60142	60142	17420	9774	5620
1992	-66970	32413	-34557	94311	0	59753	59753	15734	8404	4653
1993	-56174	27188	-28986	88595	0	59608	59608	14269	7324	3868
1994	-44864	21713	-23151	82879	0	59727	59727	12997	6382	3230
1995	-32996	15969	-17027	77164	0	60136	60136	11897	5587	2710
1996	-50948	24658	-26290	71448	0	45157	45157	8121	3648	1695
1997	-37819	18304	-19515	65732	0	46216	46216	7556	3246	1446
1998	-23979	11605	-12374	60016	0	47641	47641	7081	2910	1242
1999	-9367	4533	-4834	54300	0	49465	49465	6683	2627	1074
2000	5078	-2942	3136	48584	0	51719	51719	6352	2388	936
2001	22428	-10855	11573	42869	0	54441	54441	6079	2186	821
2002	39757	-19242	20515	37153	0	57667	57667	5854	2014	724
2003	58144	-28142	30002	31437	0	61439	61439	5669	1865	643
2004	77677	-37595	40082	25721	0	65802	65802	5520	1737	574
2005	98447	-47649	50798	20005	0	70802	70802	5400	1625	514
2006	120557	-58350	62207	14290	0	76496	76496	5303	1527	463
2007	144113	-69751	74362	8574	0	82935	82935	5227	1439	418
2008	169233	-81909	87324	2858	0	90181	90181	5167	1361	379
2009	193182	-93500	99682	0	0	99681	99681	5192	1308	349
2010	216097	-104591	111506	0	0	111505	111505	5280	1272	325
2011	240980	-116634	124346	0	0	124345	124345	5333	1234	302
2012	267987	-129706	138281	0	0	138280	138280	5412	1193	280
2013	297266	-143886	153400	0	0	153399	153399	5458	1151	259
2014	329058	-159264	169794	0	0	169793	169793	5492	1108	239
2015	363407	-175932	187565	0	0	187564	207937	6114	1180	243
TOTALS	1710470	-827869	882587	1518254	151823	2552663	1051753	-592029	-597612	-545739

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : HTGR
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-33363	0	0	-33363	0	0	0	0	0	0
1980	-129030	0	0	-129030	0	0	0	0	0	0
1981	-214003	0	0	-214003	0	0	0	0	0	0
1982	-354544	0	0	-354544	0	0	0	0	0	0
1983	-426782	0	0	-426782	0	0	0	0	0	0
1984	-304423	0	0	-304423	0	0	0	0	0	0
1985	-59109	0	0	-59109	0	0	0	0	0	0
1986	0	0	0	0	-137700	-19506	0	-134956	128351	-163811
1987	0	0	0	0	-144447	-20676	0	-122960	137336	-150748
1988	0	0	0	0	-151525	-21917	0	-117174	146949	-143667
1989	0	0	0	0	-158950	-23232	0	-111458	157235	-136405
1990	0	0	0	0	-166738	-24626	0	-105743	168202	-128865
1991	0	0	0	0	-174909	-26103	0	-100027	180019	-121020
1992	0	0	0	0	-183479	-27670	0	-94311	192620	-112840
1993	0	0	0	0	-192470	-29330	0	-88595	206104	-104291
1994	0	0	0	0	-201901	-31090	0	-82879	220531	-95339
1995	0	0	0	0	-211794	-32955	0	-77164	235968	-85944
1996	0	0	0	0	-222172	-34932	-30425	-71448	252486	-106491
1997	0	0	0	0	-233058	-37028	-30425	-65732	270160	-96083
1998	0	0	0	0	-244478	-39250	-30425	-60016	289071	-85098
1999	0	0	0	0	-256457	-41605	-30425	-54300	309366	-73482
2000	0	0	0	0	-269024	-44101	-30425	-48584	330957	-61177
2001	0	0	0	0	-282206	-46747	-30425	-42869	354124	-48123
2002	0	0	0	0	-296034	-49552	-30425	-37153	378913	-34251
2003	0	0	0	0	-310540	-52525	-30425	-31437	405437	-19490
2004	0	0	0	0	-325756	-55677	-30425	-25721	433818	-3761
2005	0	0	0	0	-341718	-59017	-30425	-20005	464185	13018
2006	0	0	0	0	-358462	-62558	-30425	-14290	496678	30941
2007	0	0	0	0	-376027	-66312	-30425	-8574	531445	50107
2008	0	0	0	0	-394452	-70291	-30425	-2858	568607	70620
2009	0	0	0	0	-413781	-74508	-30425	0	608452	89737
2010	0	0	0	0	-434056	-78979	-30425	0	651003	107583
2011	0	0	0	0	-455325	-83717	-30425	0	696617	127149
2012	0	0	0	0	-477635	-88740	-30425	0	745380	148578
2013	0	0	0	0	-501040	-94065	-30425	0	797556	172026
2014	0	0	0	0	-525591	-99709	-30425	0	853385	197660
2015	20373	0	0	20373	-551344	-105691	-30425	0	913122	225661
TOTALS	-1500880	0	0	-1500881	-8993070	-1542109	-608502	-1518254	12124138	-537796

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE 1: HTGR
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	3035	3034	-30328	-27571	-26372	-25273
1980	0	0	0	0	12903	12902	-116127	-95973	-87809	-80644
1981	0	0	0	0	21400	21399	-192603	-144705	-126640	-111460
1982	0	0	0	0	35454	35453	-319090	-217943	-182441	-153882
1983	0	0	0	0	42678	42677	-384104	-238498	-190968	-154363
1984	0	0	0	0	30442	30441	-273981	-154655	-118450	-91756
1985	0	0	0	0	5911	5910	-53198	-27299	-15999	-14847
1986	-163811	79284	-84527	134956	0	50428	50428	23524	16484	11727
1987	-150748	72961	-77787	122960	0	45172	45172	19156	12840	8754
1988	-143667	69535	-74132	117174	0	43041	43041	16593	10638	6950
1989	-136405	66019	-70386	111458	0	41071	41071	14394	8827	5527
1990	-128845	62370	-66495	105743	0	39247	39247	12504	7335	4401
1991	-121020	58573	-62447	100027	0	37579	37579	10884	6107	3511
1992	-112840	54614	-58226	94311	0	36084	36084	9501	5099	2809
1993	-104291	50476	-53815	88595	0	34779	34779	8325	4273	2256
1994	-95339	46143	-49196	82879	0	33682	33682	7329	3598	1821
1995	-85944	41597	-44347	77164	0	32816	32816	6491	3048	1478
1996	-106491	51541	-54950	71448	0	16497	16497	2966	1332	619
1997	-96083	46504	-49579	65732	0	16152	16152	2640	1134	505
1998	-85098	41187	-43911	60016	0	16104	16104	2393	983	419
1999	-73482	35565	-37917	54300	0	16362	16362	2213	869	355
2000	-61177	29609	-31568	48584	0	17015	17015	2089	785	307
2001	-48123	23291	-24832	42869	0	18036	18036	2013	724	271
2002	-34251	16577	-17674	37153	0	19478	19478	1977	679	244
2003	-19490	9433	-10057	31437	0	21379	21379	1972	648	223
2004	-3761	1820	-1941	25721	0	23779	23779	1994	627	207
2005	13018	-6301	6717	20005	0	26721	26721	2037	613	194
2006	30941	-14976	15965	14290	0	30254	30254	2097	603	183
2007	50107	-24252	25855	8574	0	34428	34428	2169	597	173
2008	70620	-34180	36440	2858	0	39297	39297	2251	593	165
2009	89737	-43433	46304	0	0	46303	46303	2411	607	162
2010	107583	-52070	55513	0	0	55512	55512	2628	633	161
2011	127149	-61540	65609	0	0	65608	65608	2824	651	159
2012	148578	-71912	76666	0	0	76665	76665	3000	661	155
2013	172026	-83261	88765	0	0	88764	88764	3158	666	149
2014	197660	-95667	101993	0	0	101992	101992	3298	665	143
2015	225661	-109220	116441	0	0	116440	116440	4022	776	160
TOTALS	-537796	260287	-277519	1518254	151823	1392557	-108353	-727736	-659536	-577989

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : CNSS
90% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER 0.070)	(3) WORKING CAPITAL-NET (ER 0.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER 0.049)	(6) OTHER OPER EXPENSES (ER 0.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER 0.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-21282	0	0	-21282	0	0	0	0	0	0
1980	-38686	0	0	-38686	0	0	0	0	0	0
1981	-82788	0	0	-82788	0	0	0	0	0	0
1982	-166078	0	0	-166078	0	0	0	0	0	0
1983	-296191	0	0	-296191	0	0	0	0	0	0
1984	-418329	0	0	-418329	0	0	0	0	0	0
1985	-181148	0	-9269	-190417	0	0	0	0	0	0
1986	0	-24980	-556	-25536	-50036	-21282	0	-106800	12322	-165796
1987	0	-26729	-590	-27318	-52488	-22559	0	-97307	13185	-159169
1988	0	-28600	-625	-29224	-55060	-23912	0	-92728	14107	-157593
1989	0	-30602	-662	-31264	-57758	-25347	0	-88205	15095	-156215
1990	0	-32744	-702	-33446	-60588	-26868	0	-83682	16152	-154986
1991	0	-35036	-744	-35780	-63557	-28480	0	-79158	17282	-153913
1992	0	-37488	-789	-38277	-66671	-30189	0	-74635	18492	-153003
1993	0	-40112	-836	-40949	-69938	-32000	0	-70112	19786	-152263
1994	0	-42920	-886	-43807	-73365	-33920	0	-65588	21171	-151702
1995	0	-45925	-940	-46864	-76959	-35955	0	-61065	22653	-151326
1996	0	-49139	-996	-50135	-80730	-38113	-24090	-56542	24259	-175236
1997	0	-52579	-1056	-53635	-84686	-40400	-24090	-52018	25936	-175258
1998	0	-56260	-1119	-57379	-88836	-42824	-24090	-47495	27752	-175493
1999	0	-60198	-1186	-61384	-93189	-45393	-24090	-42972	29694	-175949
2000	0	-64412	-1257	-65669	-97755	-48117	-24090	-38448	31773	-176637
2001	0	-68921	-1333	-70253	-102545	-51004	-24090	-33925	33997	-177567
2002	0	-73745	-1413	-75158	-107570	-54064	-24090	-29402	36377	-178749
2003	0	-78907	-1498	-80405	-112841	-57308	-24090	-24878	38923	-180194
2004	0	-84431	-1587	-86018	-118370	-60746	-24090	-20355	41648	-181913
2005	0	-90341	-1683	-92024	-124170	-64391	-24090	-15832	44563	-183920
2006	0	-96665	-1784	-98448	-130254	-68254	-24090	-11308	47682	-186225
2007	0	-103431	-1891	-105322	-136637	-72350	-24090	-6785	51020	-188841
2008	0	-110671	-2004	-112676	-143332	-76690	-24090	-2262	54591	-191783
2009	0	-118418	-2124	-120543	-150355	-81292	-24090	0	58413	-197324
2010	0	-126708	-2252	-128960	-157723	-86169	-24090	0	62502	-205480
2011	0	-135577	-2387	-137964	-165451	-91340	-24090	0	66877	-214004
2012	0	-145068	-2530	-147598	-173558	-96820	-24090	0	71558	-222910
2013	0	-155222	-2682	-157904	-182063	-102629	-24090	0	76567	-232215
2014	0	-166088	-2843	-168931	-190984	-108787	-24090	0	81927	-241934
2015	20373	-177714	50222	-107117	-200342	-115314	-24090	0	87662	-252084
TOTALS	-1184128	-2359631	0	-3543759	-3267809	-1682516	-481801	-1201502	1163946	-5469682

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE 1 CNSS
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 F+D)	(12) INCOME TAXES (-,.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	1827	1826	-19455	-17686	-16917	-16213
1980	0	0	0	0	3869	3868	-34817	-28774	-26327	-24178
1981	0	0	0	0	8279	8278	-74509	-55980	-48991	-43119
1982	0	0	0	0	16608	16607	-149470	-102090	-85460	-72082
1983	0	0	0	0	29619	29618	-266572	-165520	-132533	-107129
1984	0	0	0	0	41833	41832	-376496	-212522	-162770	-126088
1985	0	0	0	0	18115	18114	-172302	-88418	-64775	-48086
1986	-165796	80245	-85551	106800	0	21248	-4287	-2000	-1461	-997
1987	-159169	77037	-82132	97307	0	15174	-12143	-5150	-3452	-2353
1988	-157593	76275	-81318	92728	0	11409	-17814	-6868	-4403	-2877
1989	-156215	75607	-80608	88205	0	7596	-23667	-8295	-5087	-3185
1990	-154986	75013	-79973	83682	0	3708	-29737	-9475	-5558	-3335
1991	-153913	74493	-79420	79158	0	-262	-36042	-10440	-5858	-3369
1992	-153003	74053	-78950	74635	0	-4315	-42592	-11216	-6019	-3317
1993	-152263	73695	-78568	70112	0	-8456	-49405	-11827	-6072	-3207
1994	-151702	73423	-78279	65588	0	-12691	-56498	-12296	-6038	-3056
1995	-151326	73242	-78084	61065	0	-17019	-63883	-12639	-5936	-2879
1996	-175236	84814	-90422	56542	0	-33880	-84015	-15111	-6789	-3156
1997	-175258	84824	-90434	52018	0	-38416	-92051	-15051	-6468	-2881
1998	-175493	84938	-90555	47495	0	-43060	-100439	-14930	-6137	-2620
1999	-175949	85159	-90790	42972	0	-47818	-109202	-14757	-5802	-2374
2000	-176637	85492	-91145	38448	0	-52697	-118366	-14541	-5469	-2144
2001	-177567	85942	-91625	33925	0	-57700	-127953	-14290	-5140	-1931
2002	-178749	86514	-92235	29402	0	-62833	-137991	-14010	-4821	-1736
2003	-180194	87213	-92981	24878	0	-68103	-148508	-13707	-4511	-1557
2004	-181913	88046	-93867	20355	0	-73512	-159530	-13385	-4214	-1394
2005	-183920	89017	-94903	15832	0	-79071	-171095	-13051	-3930	-1246
2006	-186225	90132	-96093	11308	0	-84785	-183233	-12706	-3660	-1112
2007	-188841	91399	-97442	6785	0	-90657	-195979	-12354	-3404	-991
2008	-191783	92822	-98961	2262	0	-96699	-209375	-11999	-3162	-882
2009	-197324	95505	-101819	0	0	-101819	-222362	-11585	-2920	-781
2010	-205480	99452	-106028	0	0	-106028	-234988	-11130	-2684	-687
2011	-214004	103577	-110427	0	0	-110427	-248391	-10695	-2467	-606
2012	-222910	107888	-115022	0	0	-115022	-262620	-10280	-2268	-534
2013	-232215	112391	-119824	0	0	-119824	-277728	-9883	-2085	-470
2014	-241934	117095	-124839	0	0	-124839	-293770	-9503	-1918	-414
2015	-252084	122008	-130076	0	0	-130076	-237193	-6975	-1327	-279
TOTALS	-5469682	2647311	-2822371	1201502	120150	-1500719	-5044478	-1011118	-666772	-493246

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : CNSS
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) SACKUP EXPENSES (ER \$.070)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.049)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-21282	0	0	-21282	0	0	0	0	0	0
1980	-38686	0	0	-38686	0	0	0	0	0	0
1981	-82788	0	0	-82788	0	0	0	0	0	0
1982	-166078	0	0	-166078	0	0	0	0	0	0
1983	-296191	0	0	-296191	0	0	0	0	0	0
1984	-418329	0	0	-418329	0	0	0	0	0	0
1985	-181148	0	-9269	-190417	0	0	0	0	0	0
1986	0	-27756	-556	-28312	-55595	-21282	0	-106800	12322	-171355
1987	0	-29699	-590	-30288	-58319	-22559	0	-97307	13185	-165000
1988	0	-31778	-625	-32403	-61177	-23912	0	-92728	14107	-163710
1989	0	-34002	-662	-34665	-64174	-25347	0	-89205	15095	-162632
1990	0	-36382	-702	-37085	-67319	-26868	0	-83682	16152	-161717
1991	0	-38929	-744	-39673	-70618	-28480	0	-79158	17282	-160974
1992	0	-41654	-789	-42443	-74078	-30189	0	-74635	18492	-160410
1993	0	-44570	-836	-45406	-77708	-32000	0	-70112	19786	-160033
1994	0	-47690	-886	-48576	-81515	-33920	0	-65588	21171	-159853
1995	0	-51028	-940	-51968	-85510	-35955	0	-61065	22653	-159877
1996	0	-54600	-996	-55596	-89700	-38113	-24090	-56542	24239	-184205
1997	0	-58422	-1056	-59478	-94095	-40400	-24090	-52018	25936	-184667
1998	0	-62512	-1119	-63631	-98706	-42824	-24090	-47495	27752	-185363
1999	0	-66888	-1186	-68074	-103542	-45393	-24090	-42972	29694	-186303
2000	0	-71570	-1257	-72827	-108616	-48117	-24090	-38448	31773	-187498
2001	0	-76580	-1333	-77913	-113938	-51004	-24090	-33925	33997	-188960
2002	0	-81940	-1413	-83353	-119521	-54064	-24090	-29402	36377	-190700
2003	0	-87676	-1498	-89174	-125377	-57308	-24090	-24878	38923	-192730
2004	0	-93813	-1587	-95401	-131521	-60746	-24090	-20355	41608	-195064
2005	0	-100380	-1683	-102063	-137965	-64391	-24090	-15832	44563	-197715
2006	0	-107407	-1784	-109191	-144726	-68254	-24090	-11308	47682	-200696
2007	0	-114925	-1891	-116816	-151817	-72350	-24090	-6785	51020	-204022
2008	0	-122970	-2004	-124974	-159256	-76690	-24090	-2262	54591	-207707
2009	0	-131578	-2124	-133702	-167060	-81292	-24090	0	58413	-214029
2010	0	-140789	-2252	-143040	-175246	-86169	-24090	0	62502	-223003
2011	0	-150644	-2387	-153031	-183833	-91340	-24090	0	66877	-232386
2012	0	-161189	-2530	-163719	-192841	-96820	-24090	0	71558	-242192
2013	0	-172472	-2682	-175154	-202290	-102629	-24090	0	76567	-252442
2014	0	-184545	-2843	-187388	-212202	-108787	-24090	0	81927	-263152
2015	20373	-197463	50222	-126866	-222600	-115314	-24090	0	87662	-274342
TOTALS	-1184128	-2621854	0	-3805981	-3630862	-1682516	-481801	-1201502	1163946	-5832735

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISMAR COGENERATION
CASE : CNSS
100% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 F+D)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DWF,10)	(19) PRESENT WORTH=NCF (DWF,15)	(20) PRESENT WORTH=NCF (DWF,20)
1979	0	0	0	0	1827	1826	-19455	-17686	-16917	-16213
1980	0	0	0	0	3869	3868	-34817	-28774	-26327	-24178
1981	0	0	0	0	8279	8278	-74509	-55980	-48991	-43119
1982	0	0	0	0	16608	16607	-149470	-102090	-85460	-72082
1983	0	0	0	0	29619	29618	-266572	-165520	-132533	-107129
1984	0	0	0	0	41833	41832	-376496	-212522	-162770	-126088
1985	0	0	0	0	18115	18114	-172302	-88418	-64775	-48086
1986	-171355	82935	-88420	106800	0	18379	-9932	-4633	-3247	-2310
1987	-165000	79860	-85140	97307	0	12166	-18121	-7685	-5151	-3512
1988	-163710	79235	-84475	92728	0	8252	-24150	-9311	-5970	-3900
1989	-162632	78713	-83919	88205	0	4285	-30379	-10648	-6530	-4089
1990	-161717	78271	-83446	83682	0	235	-36849	-11741	-6827	-4133
1991	-160974	77911	-83063	79158	0	-3905	-43578	-12623	-7083	-4073
1992	-160410	77638	-82772	74635	0	-8137	-50580	-13319	-7148	-3940
1993	-160033	77456	-82577	70112	0	-12465	-57871	-13854	-7112	-3756
1994	-159853	77368	-82485	65588	0	-16897	-65473	-14249	-6997	-3541
1995	-159877	77380	-82497	61065	0	-21432	-73400	-14522	-6821	-3308
1996	-164205	89155	-95050	56542	0	-38508	-94104	-16925	-7604	-3535
1997	-164667	89378	-95289	52018	0	-43271	-102749	-16800	-7220	-3216
1998	-165363	89715	-95648	47495	0	-48153	-111784	-16616	-6830	-2916
1999	-166303	90170	-96133	42972	0	-53161	-121235	-16383	-6441	-2635
2000	-167498	90748	-96750	38448	0	-58302	-131129	-16109	-6058	-2375
2001	-168960	91456	-97504	33925	0	-63579	-141492	-15802	-5684	-2136
2002	-190700	92298	-98402	29402	0	-69000	-152353	-15468	-5322	-1916
2003	-192730	93281	-99449	24878	0	-74571	-163745	-15113	-4974	-1716
2004	-195064	94411	-100653	20355	0	-80298	-175699	-14742	-4641	-1535
2005	-197715	95694	-102021	15832	0	-86189	-188252	-14359	-4324	-1370
2006	-200696	97136	-103560	11308	0	-92252	-201443	-13969	-4024	-1222
2007	-204022	98746	-105276	6785	0	-98491	-215307	-13573	-3740	-1088
2008	-207707	100530	-107177	2262	0	-104915	-229889	-13175	-3472	-968
2009	-214029	103589	-110440	0	0	-110440	-244142	-12719	-3206	-857
2010	-223003	107933	-115070	0	0	-115070	-258110	-12225	-2948	-755
2011	-232386	112474	-119912	0	0	-119912	-272943	-11752	-2710	-665
2012	-242192	117221	-124971	0	0	-124971	-288690	-11300	-2493	-587
2013	-252442	122181	-130261	0	0	-130261	-305415	-10868	-2293	-517
2014	-263152	127365	-135787	0	0	-135787	-323175	-10454	-2110	-456
2015	-274342	132781	-141561	0	0	-141561	-268427	-7894	-1524	-316
TOTALS	-5832735	12823029	-3009702	1201502	120150	-1688056	-5494037	-1059805	-688321	-504222

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : CNSS
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.070)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.049)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-21282	0	0	-21282	0	0	0	0	0	0
1980	-38686	0	0	-38686	0	0	0	0	0	0
1981	-82788	0	0	-82788	0	0	0	0	0	0
1982	-166078	0	0	-166078	0	0	0	0	0	0
1983	-296191	0	0	-296191	0	0	0	0	0	0
1984	-418329	0	0	-418329	0	0	0	0	0	0
1985	-181148	0	-9269	-190417	0	0	0	0	0	0
1986	0	-41633	-556	-42189	-83392	-21282	0	-106800	12322	-199152
1987	0	-44547	-590	-45137	-87478	-22559	0	-97307	13185	-194159
1988	0	-47666	-625	-48291	-91765	-23912	0	-92728	14107	-194298
1989	0	-51002	-662	-51665	-96261	-25347	0	-88205	15095	-194718
1990	0	-54572	-702	-55274	-100978	-26868	0	-83682	16152	-195376
1991	0	-58392	-744	-59137	-105926	-28480	0	-79158	17282	-196282
1992	0	-62480	-789	-63269	-111116	-30189	0	-74635	18492	-197448
1993	0	-66854	-836	-67690	-116561	-32000	0	-70112	19786	-198886
1994	0	-71533	-886	-72420	-122272	-33920	0	-65588	21171	-200609
1995	0	-76541	-940	-77480	-128264	-35955	0	-61065	22653	-202631
1996	0	-81898	-996	-82894	-134549	-38113	-24090	-56542	24239	-229054
1997	0	-87631	-1056	-88687	-141142	-40400	-24090	-52018	25936	-231713
1998	0	-93766	-1119	-94885	-148057	-42824	-24090	-47495	27752	-234715
1999	0	-100329	-1186	-101515	-155312	-45393	-24090	-42972	29694	-238073
2000	0	-107352	-1257	-108610	-162923	-48117	-24090	-38448	31773	-241805
2001	0	-114867	-1333	-116200	-170906	-51004	-24090	-33925	33967	-245928
2002	0	-122907	-1413	-124320	-179280	-54064	-24090	-29402	36377	-250459
2003	0	-131511	-1498	-133009	-188065	-57308	-24090	-24878	38923	-255418
2004	0	-140717	-1587	-142304	-197280	-60746	-24090	-20355	41648	-260824
2005	0	-150567	-1683	-152250	-206947	-64391	-24090	-15832	44543	-266696
2006	0	-161107	-1784	-162890	-217087	-68254	-24090	-11308	47682	-273058
2007	0	-172384	-1891	-174275	-227724	-72350	-24090	-6785	51020	-279929
2008	0	-184451	-2004	-186455	-238883	-76690	-24090	-2262	54591	-287334
2009	0	-197363	-2124	-199487	-250588	-81292	-24090	0	58413	-297557
2010	0	-211178	-2252	-213430	-262867	-86169	-24090	0	62502	-310625
2011	0	-225960	-2387	-228347	-275747	-91340	-24090	0	66877	-324300
2012	0	-241778	-2530	-244308	-289259	-96820	-24090	0	71588	-338611
2013	0	-258702	-2682	-261384	-303433	-102629	-24090	0	76547	-353585
2014	0	-276811	-2843	-279654	-318301	-108787	-24090	0	81927	-369251
2015	20373	-296188	50222	-225591	-333898	-115314	-24090	0	87662	-385640
TOTALS	-1144128	-3932687	0	-5116818	-5446261	-1682516	-481801	-1201502	1163946	-7648134

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISMAR COGENERATION
CASE : CNSS
150% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	1827	1826	-19455	-17686	-16917	-16213
1980	0	0	0	0	3869	3868	-34817	-28774	-26327	-24178
1981	0	0	0	0	8279	8276	-74509	-55980	-48991	-43119
1982	0	0	0	0	16608	16607	-149470	-102090	-85460	-72082
1983	0	0	0	0	29619	29618	-266572	-165520	-132533	-107129
1984	0	0	0	0	41833	41832	-376496	-212522	-162770	-126088
1985	0	0	0	0	18115	18114	-172302	-88418	-64775	-48086
1986	-199152	96389	-102763	106800	0	4036	-38152	-17798	-12472	-8873
1987	-194159	93973	-100186	97307	0	-2879	-48016	-20363	-13649	-9306
1988	-194298	94040	-100258	92728	0	-7530	-55821	-21521	-11798	-9015
1989	-194718	94243	-100475	88205	0	-12270	-63935	-22409	-13742	-8605
1990	-195376	94561	-100815	83682	0	-17133	-72407	-23071	-13533	-8121
1991	-196282	95000	-101282	79158	0	-22124	-81261	-23538	-13267	-7595
1992	-197448	95564	-101884	74635	0	-27249	-90518	-23836	-12743	-7050
1993	-198686	96260	-102626	70112	0	-32514	-100204	-23988	-12315	-6504
1994	-200609	97094	-103515	65588	0	-37927	-110347	-24015	-11792	-5968
1995	-202631	98073	-104558	61065	0	-43493	-120973	-23934	-11242	-5453
1996	-229054	110862	-118192	56542	0	-61650	-144544	-25998	-11680	-5429
1997	-231713	112149	-119564	52018	0	-67546	-156233	-25545	-10978	-4890
1998	-234715	113601	-121114	47495	0	-73619	-168504	-25047	-10296	-4395
1999	-238073	115227	-122846	42972	0	-79874	-181389	-24511	-9637	-3943
2000	-241805	117033	-124772	38448	0	-86324	-194934	-23947	-9066	-3531
2001	-245928	119028	-126900	33925	0	-92975	-209175	-23360	-8463	-3157
2002	-250459	121222	-129237	29402	0	-99835	-224155	-22757	-7831	-2820
2003	-255418	123622	-131796	24878	0	-106918	-239927	-22144	-7288	-2515
2004	-260824	126238	-134586	20355	0	-114231	-256535	-21525	-6776	-2241
2005	-266696	129081	-137615	15832	0	-121783	-274033	-20903	-6294	-1995
2006	-273058	132159	-140899	11308	0	-129591	-292481	-20282	-5802	-1774
2007	-279929	135485	-144444	6785	0	-137659	-311934	-19664	-5418	-1577
2008	-287334	139069	-148265	2262	0	-146003	-332458	-19053	-5021	-1401
2009	-297557	144017	-153540	0	0	-153540	-353027	-18392	-4636	-1239
2010	-310625	150342	-160283	0	0	-160283	-373713	-17700	-4268	-1093
2011	-324300	156961	-167339	0	0	-167339	-395686	-17037	-3929	-965
2012	-338611	163887	-174724	0	0	-174724	-419032	-16402	-3618	-851
2013	-353585	171135	-182450	0	0	-182450	-443834	-15793	-3333	-751
2014	-369251	178717	-190534	0	0	-190534	-470188	-15210	-3070	-663
2015	-385540	186649	-196891	0	0	-196891	-494582	-12426	-2411	-499
TOTALS	-7648134	3701681	-3946453	1201502	120150	-2624801	-7741619	-1303206	-796033	-559097

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAM COGENERATION
CASE : CNSS
2002 FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER 0.070)	(3) WORKING CAPITAL-NET (ER 0.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER 0.049)	(6) OTHER OPER EXPENSES (ER 0.060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX CREDIT FOR POWER (ER 0.070)	(9) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-21292	0	0	-21282	0	0	0	0	0
1980	-38686	0	0	-38686	0	0	0	0	0
1981	-82788	0	0	-82788	0	0	0	0	0
1982	-166078	0	0	-166078	0	0	0	0	0
1983	-296191	0	0	-296191	0	0	0	0	0
1984	-418329	0	0	-418329	0	0	0	0	0
1985	-181148	0	-9269	-190417	0	0	0	0	0
1986	0	-55511	-556	-56067	-111190	-21282	0	-106800	-226950
1987	0	-59397	-590	-59986	-116638	-22559	0	-97307	-223320
1988	0	-63555	-625	-64179	-122354	-23912	0	-92728	-220887
1989	0	-68003	-662	-68666	-128349	-25347	0	-88205	-226806
1990	0	-72764	-702	-73466	-134638	-26868	0	-83682	-229036
1991	0	-77657	-744	-78401	-141235	-28480	0	-79158	-231591
1992	0	-83307	-789	-84096	-148156	-30189	0	-74635	-234488
1993	0	-89139	-836	-89975	-155415	-32000	0	-70112	-237741
1994	0	-95378	-866	-96245	-163031	-33920	0	-65588	-241368
1995	0	-102055	-940	-102994	-171019	-35955	0	-61065	-245386
1996	0	-109199	-996	-110195	-179399	-38113	-24090	-56542	-273905
1997	0	-116842	-1056	-117898	-188190	-40400	-24090	-52018	-278762
1998	0	-125021	-1119	-126140	-197411	-42824	-24090	-47495	-284068
1999	0	-133773	-1186	-134959	-207084	-45393	-24090	-42972	-289845
2000	0	-143137	-1257	-144394	-217231	-48117	-24090	-38448	-296114
2001	0	-153157	-1333	-154490	-227876	-51004	-24090	-33925	-302898
2002	0	-163878	-1413	-165291	-239042	-54064	-24090	-29402	-310221
2003	0	-175349	-1498	-176847	-250755	-57308	-24090	-24878	-318108
2004	0	-187623	-1587	-189211	-263042	-60746	-24090	-20355	-326585
2005	0	-200757	-1683	-202440	-275931	-64391	-24090	-15832	-335680
2006	0	-214810	-1784	-216594	-289451	-68254	-24090	-11308	-345422
2007	0	-229847	-1891	-231737	-303634	-72350	-24090	-6785	-355839
2008	0	-245936	-2004	-247940	-318512	-76690	-24090	-2262	-366963
2009	0	-263152	-2124	-265276	-334120	-81292	-24090	0	-381089
2010	0	-281572	-2252	-283824	-350491	-86169	-24090	0	-398249
2011	0	-301282	-2397	-303679	-367666	-91340	-24090	0	-416218
2012	0	-322372	-2530	-324902	-385681	-96820	-24090	0	-435033
2013	0	-344938	-2682	-347620	-404579	-102629	-24090	0	-454731
2014	0	-369084	-2843	-371927	-424404	-108787	-24090	0	-475354
2015	20373	-394920	50222	-324322	-445200	-115314	-24090	0	-496942
TOTALS	-1184128	-5243614	0	-6427740	-7261724	-1682516	-481801	-1201502	-9463598

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : CANS
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWC)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	1827	1826	-19455	-17686	-16917	-16213
1980	0	0	0	0	3969	3868	-34817	-28774	-26327	-24178
1981	0	0	0	0	8279	8278	-74509	-55980	-48961	-43119
1982	0	0	0	0	16608	16607	-149470	-102090	-85460	-72082
1983	0	0	0	0	29619	29618	-266572	-165520	-132533	-107129
1984	0	0	0	0	41833	41832	-376496	-212522	-162770	-126088
1985	0	0	0	0	18115	18114	-172302	-88418	-64775	-48086
1986	-226950	109843	-117107	106800	0	-10307	-66374	-30964	-21698	-15436
1987	-223320	108086	-115234	97307	0	-17927	-77913	-33043	-22148	-15100
1988	-224887	108845	-116042	92728	0	-33314	-87493	-33732	-21627	-14131
1989	-226206	109774	-117032	88205	0	-28827	-97493	-34171	-20955	-13121
1990	-229036	110853	-118183	83682	0	-34501	-107967	-34402	-20190	-12109
1991	-231591	112090	-119501	79158	0	-40343	-118944	-34454	-19332	-11117
1992	-234488	113492	-120996	74635	0	-46361	-130457	-34353	-18427	-10161
1993	-237741	115066	-122675	70112	0	-52563	-142538	-34122	-17517	-9251
1994	-241368	116822	-124546	65588	0	-58958	-155223	-33781	-16588	-8396
1995	-245386	118766	-126620	61065	0	-65555	-168549	-33347	-15663	-7597
1996	-273905	132569	-141336	56542	0	-84794	-194989	-35070	-15756	-7324
1997	-278762	134920	-143842	52018	0	-91824	-209722	-34291	-14736	-6564
1998	-284068	137489	-146579	47495	0	-99084	-225224	-33478	-13761	-5875
1999	-289845	140284	-149561	42972	0	-106589	-241548	-32641	-12834	-5250
2000	-296114	143318	-152796	38448	0	-114348	-258742	-31785	-11954	-4687
2001	-302898	146602	-156296	33925	0	-122371	-276860	-30919	-11123	-4179
2002	-310221	150146	-160075	29402	0	-130673	-295963	-30048	-10339	-3723
2003	-318108	153964	-164144	24878	0	-139266	-316113	-29176	-9603	-3314
2004	-326585	158067	-168518	20355	0	-148163	-337374	-28308	-8912	-2947
2005	-335680	162469	-173211	15832	0	-157379	-359819	-27446	-8265	-2619
2006	-345422	167184	-178238	11308	0	-166930	-383524	-26595	-7660	-2327
2007	-355839	172226	-183613	6785	0	-176828	-408565	-25756	-7096	-2065
2008	-366963	177610	-189353	2262	0	-187091	-435031	-24931	-6570	-1833
2009	-381089	184446	-196643	0	0	-196643	-461919	-24065	-6066	-1622
2010	-398249	192752	-205497	0	0	-205497	-489321	-23175	-5588	-1432
2011	-416218	201449	-214769	0	0	-214769	-518438	-22322	-5148	-1264
2012	-435033	210555	-224478	0	0	-224478	-549380	-21504	-4704	-1116
2013	-454731	220090	-234641	0	0	-234641	-582261	-20719	-4372	-986
2014	-475354	230071	-245283	0	0	-245283	-617210	-19966	-4030	-871
2015	-496942	240519	-256423	0	0	-256423	-658745	-17079	-3297	-683
TOTALS	-9463598	4580367	-4883232	1201502	120150	-3561580	-9989320	-1546619	-903755	-613975

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GRISMAR COGENERATION
CASE : EXIST. PLANTS
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-63454	-63454	0	0	0	0	0	0
1986	0	0	-3807	-3807	-331422	-18577	0	0	0	-349999
1987	0	0	-4036	-4036	-354622	-19692	0	0	0	-374313
1988	0	0	-4278	-4278	-379445	-20873	0	0	0	-400318
1989	0	0	-4534	-4534	-406006	-22126	0	0	0	-428132
1990	0	0	-4807	-4807	-434427	-23453	0	0	0	-457880
1991	0	0	-5095	-5095	-464837	-24860	0	0	0	-489697
1992	0	0	-5401	-5401	-497375	-26352	0	0	0	-523727
1993	0	0	-5725	-5725	-532191	-27933	0	0	0	-560124
1994	0	0	-6068	-6068	-569445	-29609	0	0	0	-599054
1995	0	0	-6432	-6432	-609306	-31385	0	0	0	-640691
1996	0	0	-6818	-6818	-651957	-33269	0	0	0	-685226
1997	0	0	-7227	-7227	-697594	-35265	0	0	0	-732859
1998	0	0	-7661	-7661	-746426	-37381	0	0	0	-783806
1999	0	0	-8121	-8121	-798676	-39623	0	0	0	-838299
2000	0	0	-8608	-8608	-854583	-42001	0	0	0	-896584
2001	0	0	-9124	-9124	-914404	-44521	0	0	0	-958925
2002	0	0	-9672	-9672	-978412	-47192	0	0	0	-1025604
2003	0	0	-10252	-10252	-1046901	-50024	0	0	0	-1096925
2004	0	0	-10867	-10867	-1120184	-53025	0	0	0	-1173209
2005	0	0	-11519	-11519	-1198597	-56207	0	0	0	-1254804
2006	0	0	-12210	-12210	-1282499	-59579	0	0	0	-1342078
2007	0	0	-12943	-12943	-1372274	-63154	0	0	0	-1435427
2008	0	0	-13720	-13720	-1468333	-66943	0	0	0	-1535276
2009	0	0	-14543	-14543	-1571116	-70959	0	0	0	-1642076
2010	0	0	-15415	-15415	-1681094	-75217	0	0	0	-1756311
2011	0	0	-16340	-16340	-1798771	-79730	0	0	0	-1878501
2012	0	0	-17321	-17321	-1924685	-84514	0	0	0	-2009199
2013	0	0	-18360	-18360	-2059413	-89585	0	0	0	-2148998
2014	0	0	-19461	-19461	-2203572	-94960	0	0	0	-2298532
2015	0	0	343817	343817	-2357822	-100657	0	0	0	-2458479
TOTALS	0	0	0	-2	-31306388	-1468664	0	0	0	-32775051

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISHAR COGENERATION
CASE : EXIST. PLANTS
90% FUEL COST

YEAR	(11) TOTAL FXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (= .48*11)	(13) TOTAL FXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (= .10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-63454	-32562	-23855	-17709
1986	-349999	169399	-180600	0	0	-180600	-184407	-86027	-60283	-42887
1987	-374313	181167	-193146	0	0	-193146	-197182	-83624	-56051	-38215
1988	-400318	193753	-206565	0	0	-206565	-210843	-81289	-52117	-34052
1989	-428132	207215	-226917	0	0	-226917	-225451	-79019	-48459	-30343
1990	-457880	221613	-236267	0	0	-236267	-241074	-76814	-45058	-27038
1991	-489697	237013	-252684	0	0	-252684	-257779	-74669	-41896	-24093
1992	-523727	253483	-270244	0	0	-270244	-275645	-72586	-38957	-21469
1993	-560124	271100	-289024	0	0	-289024	-294749	-70561	-36223	-19131
1994	-599054	289941	-309113	0	0	-309113	-315181	-68593	-33622	-17047
1995	-640691	310094	-330597	0	0	-330597	-337029	-66679	-31319	-15191
1996	-685226	331649	-353577	0	0	-353577	-360395	-64820	-29122	-13537
1997	-732859	354703	-378156	0	0	-378156	-385383	-63013	-27079	-12063
1998	-783806	379362	-404444	0	0	-404444	-412105	-61257	-25120	-10749
1999	-838299	405736	-432563	0	0	-432563	-440684	-59550	-23414	-9579
2000	-896584	433946	-462638	0	0	-462638	-471246	-57891	-21772	-8536
2001	-958925	464119	-494806	0	0	-494806	-503930	-56278	-20245	-7607
2002	-1025604	496392	-529212	0	0	-529212	-538884	-54711	-18826	-6779
2003	-1096925	530911	-566014	0	0	-566014	-576266	-53187	-17566	-6041
2004	-1173209	567833	-605376	0	0	-605376	-616243	-51706	-16278	-5383
2005	-1254804	607324	-647480	0	0	-647480	-658999	-50267	-15137	-4797
2006	-1342078	649565	-692513	0	0	-692513	-704723	-48868	-14076	-4275
2007	-1435427	694746	-740681	0	0	-740681	-753624	-47508	-13069	-3810
2008	-1535276	743073	-792203	0	0	-792203	-805923	-46186	-12172	-3395
2009	-1642076	794764	-847312	0	0	-847312	-861855	-44902	-11319	-3026
2010	-1756311	850054	-906257	0	0	-906257	-921672	-43653	-10526	-2696
2011	-1878501	909194	-969307	0	0	-969307	-985647	-42439	-9788	-2403
2012	-2009199	972452	-1036747	0	0	-1036747	-1054068	-41259	-9102	-2141
2013	-2148998	1040114	-1108884	0	0	-1108884	-1127244	-40112	-8464	-1908
2014	-2292532	1112489	-1186043	0	0	-1186043	-1205504	-38997	-7871	-1701
2015	-2458479	1169903	-1268576	0	0	-1268576	-924759	-27196	-5251	-1087
TOTALS	-32775051	15863107	-16911946	0	0	-16911946	-16911948	-1786205	-784160	-398675

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : EXIST. PLANTS
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,000)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-63454	-63454	0	0	0	0	0	0
1986	0	0	-3807	-3807	-368247	-18577	0	0	0	-386824
1987	0	0	-4036	-4036	-394024	-19692	0	0	0	-413716
1988	0	0	-4278	-4278	-421606	-20873	0	0	0	-442479
1989	0	0	-4534	-4534	-451118	-22126	0	0	0	-473244
1990	0	0	-4807	-4807	-482697	-23453	0	0	0	-506150
1991	0	0	-5095	-5095	-516485	-24860	0	0	0	-541346
1992	0	0	-5401	-5401	-552639	-26352	0	0	0	-578991
1993	0	0	-5725	-5725	-591324	-27933	0	0	0	-619257
1994	0	0	-6068	-6068	-632717	-29609	0	0	0	-662326
1995	0	0	-6432	-6432	-677007	-31385	0	0	0	-708393
1996	0	0	-6818	-6818	-724398	-33269	0	0	0	-757666
1997	0	0	-7227	-7227	-775105	-35265	0	0	0	-810370
1998	0	0	-7661	-7661	-829363	-37381	0	0	0	-866743
1999	0	0	-8121	-8121	-887418	-39623	0	0	0	-927042
2000	0	0	-8608	-8608	-949538	-42001	0	0	0	-991538
2001	0	0	-9124	-9124	-1016005	-44521	0	0	0	-1060526
2002	0	0	-9672	-9672	-1087126	-47192	0	0	0	-1134318
2003	0	0	-10252	-10252	-1163224	-50024	0	0	0	-1213248
2004	0	0	-10867	-10867	-1244650	-53025	0	0	0	-1297675
2005	0	0	-11519	-11519	-1331776	-56207	0	0	0	-1387982
2006	0	0	-12210	-12210	-1425000	-59579	0	0	0	-1484579
2007	0	0	-12943	-12943	-1524750	-63154	0	0	0	-1587904
2008	0	0	-13720	-13720	-1631482	-66943	0	0	0	-1698425
2009	0	0	-14543	-14543	-1745686	-70959	0	0	0	-1816646
2010	0	0	-15415	-15415	-1867884	-75217	0	0	0	-1943101
2011	0	0	-16340	-16340	-1998636	-79730	0	0	0	-2078366
2012	0	0	-17321	-17321	-2138541	-84514	0	0	0	-2223055
2013	0	0	-18360	-18360	-2288239	-89585	0	0	0	-2377823
2014	0	0	-19461	-19461	-2448415	-94960	0	0	0	-2543375
2015	0	0	343817	343817	-2619804	-100657	0	0	0	-2720462
TOTALS	0	0	0	-2	-34784907	-1468664	0	0	0	-36253570

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISHAR COGENERATION
CASE : EXIST. PLANTS
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-63454	-32562	-23895	-17709
1986	-386824	187222	-199602	0	0	-199602	-203409	-94892	-66495	-47306
1987	-413716	200238	-213478	0	0	-213478	-217514	-92247	-61831	-42156
1988	-442479	214159	-228320	0	0	-228320	-232598	-89677	-57495	-37566
1989	-473244	229050	-244194	0	0	-244194	-248728	-87178	-53462	-33476
1990	-506150	244976	-261174	0	0	-261174	-265981	-84750	-49714	-29832
1991	-541346	262011	-279335	0	0	-279335	-284430	-82389	-46228	-26584
1992	-578991	280231	-298760	0	0	-298760	-304161	-80095	-42987	-23690
1993	-619257	299720	-319537	0	0	-319537	-325262	-77865	-39973	-21111
1994	-662326	320565	-341761	0	0	-341761	-347829	-75698	-37171	-18813
1995	-708393	342862	-365531	0	0	-365531	-371963	-73591	-34565	-16766
1996	-757666	366710	-390956	0	0	-390956	-397774	-71543	-32142	-14941
1997	-810370	392219	-418151	0	0	-418151	-425378	-69553	-29899	-13315
1998	-866743	419503	-447240	0	0	-447240	-454901	-67618	-27795	-11866
1999	-927042	448688	-478354	0	0	-478354	-486475	-65738	-25847	-10574
2000	-991538	479904	-511634	0	0	-511634	-520242	-63910	-24035	-9424
2001	-1060526	513294	-547232	0	0	-547232	-556356	-62133	-22351	-8398
2002	-1134318	549009	-585309	0	0	-585309	-594981	-60406	-20785	-7484
2003	-1213248	587212	-626036	0	0	-626036	-636288	-58727	-19329	-6670
2004	-1297675	626074	-669601	0	0	-669601	-680468	-57095	-17975	-5944
2005	-1387982	671783	-716199	0	0	-716199	-727718	-55509	-16716	-5297
2006	-1484579	718536	-766043	0	0	-766043	-778253	-53967	-15545	-4721
2007	-1587904	768545	-819359	0	0	-819359	-832302	-52468	-14456	-4208
2008	-1698425	822037	-876388	0	0	-876388	-890108	-51011	-13403	-3750
2009	-1816646	879256	-937390	0	0	-937390	-951933	-49594	-12562	-3342
2010	-1943101	940461	-1002640	0	0	-1002640	-1018055	-48218	-11624	-2978
2011	-2078366	1005929	-1072437	0	0	-1072437	-1088777	-46879	-10812	-2654
2012	-2223055	1075956	-1147097	0	0	-1147097	-1164418	-45578	-10055	-2366
2013	-2377823	1150866	-1226957	0	0	-1226957	-1245317	-44314	-9351	-2108
2014	-2543375	1230993	-1312382	0	0	-1312382	-1331843	-43084	-8696	-1879
2015	-2720462	1316703	-1403759	0	0	-1403759	-1059942	-31171	-6018	-1246
TOTALS	-36253570	17546714	-18706856	0	0	-18706856	-18706858	-1969440	-263126	-438158

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISMAR COGENERATION
CASE : EXIST. PLANTS
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-63454	-63454	0	0	0	0	0	0
1986	0	0	-3807	-3807	-552371	-18577	0	0	0	-570948
1987	0	0	-4036	-4036	-591037	-19692	0	0	0	-610729
1988	0	0	-4278	-4278	-632410	-20873	0	0	0	-653283
1989	0	0	-4534	-4534	-676678	-22126	0	0	0	-696804
1990	0	0	-4807	-4807	-724046	-23453	0	0	0	-747499
1991	0	0	-5095	-5095	-774729	-24860	0	0	0	-799589
1992	0	0	-5401	-5401	-828960	-26352	0	0	0	-855312
1993	0	0	-5725	-5725	-886987	-27933	0	0	0	-914920
1994	0	0	-6068	-6068	-949076	-29609	0	0	0	-978685
1995	0	0	-6432	-6432	-1015512	-31385	0	0	0	-1046897
1996	0	0	-6818	-6818	-1086597	-33269	0	0	0	-1119866
1997	0	0	-7227	-7227	-1162659	-35265	0	0	0	-1197924
1998	0	0	-7661	-7661	-1244045	-37381	0	0	0	-1281426
1999	0	0	-8121	-8121	-1331129	-39623	0	0	0	-1370752
2000	0	0	-8608	-8608	-1424308	-42001	0	0	0	-1466308
2001	0	0	-9124	-9124	-1524009	-44521	0	0	0	-1568530
2002	0	0	-9672	-9672	-1630690	-47192	0	0	0	-1677882
2003	0	0	-10252	-10252	-1744838	-50024	0	0	0	-1794862
2004	0	0	-10867	-10867	-1866977	-53025	0	0	0	-1920002
2005	0	0	-11519	-11519	-1997665	-56207	0	0	0	-2053872
2006	0	0	-12210	-12210	-2137502	-59579	0	0	0	-2197081
2007	0	0	-12943	-12943	-2287127	-63154	0	0	0	-2350281
2008	0	0	-13720	-13720	-2447226	-66943	0	0	0	-2514169
2009	0	0	-14543	-14543	-2618532	-70959	0	0	0	-2689491
2010	0	0	-15415	-15415	-2801829	-75217	0	0	0	-2877046
2011	0	0	-16340	-16340	-2997957	-79730	0	0	0	-3077687
2012	0	0	-17321	-17321	-3207814	-84514	0	0	0	-3292328
2013	0	0	-18360	-18360	-3432361	-89585	0	0	0	-3521946
2014	0	0	-19461	-19461	-3672626	-94960	0	0	0	-3767586
2015	0	0	-343817	-343817	-3929710	-100657	0	0	0	-4030368
TOTALS	0	0	0	-2	-52177406	-1468664	0	0	0	-53646071

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: GEISHAR COGENERATION
CASE : EXIST. PLANTS
150% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.48*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-63454	-32562	-23855	-17709
1986	-570944	276336	-294610	0	0	-294610	-298417	-139214	-97553	-69402
1987	-610729	295592	-315137	0	0	-315137	-319173	-135361	-90729	-61858
1988	-653283	316188	-337095	0	0	-337095	-341373	-131614	-84342	-55134
1989	-698804	338221	-360583	0	0	-360583	-365117	-127971	-78479	-49140
1990	-747499	361789	-385710	0	0	-385710	-390517	-124431	-72990	-43799
1991	-794589	387001	-412588	0	0	-412588	-417683	-120988	-67845	-39038
1992	-855312	413970	-441342	0	0	-441342	-446743	-117641	-63138	-34795
1993	-914920	442821	-472099	0	0	-472099	-477824	-114387	-58722	-31013
1994	-978685	473683	-505002	0	0	-505002	-511070	-111224	-54615	-27643
1995	-1046897	506698	-540199	0	0	-540199	-546631	-108148	-50796	-24638
1996	-1119866	542015	-577851	0	0	-577851	-584669	-105158	-47244	-21961
1997	-1197924	579795	-618129	0	0	-618129	-625356	-102251	-43941	-19574
1998	-1281426	620210	-661216	0	0	-661216	-668877	-99424	-40869	-17447
1999	-1370752	663443	-707309	0	0	-707309	-715430	-96676	-38011	-15551
2000	-1466308	709693	-756615	0	0	-756615	-765223	-94005	-35354	-13861
2001	-1568530	759168	-809362	0	0	-809362	-818486	-91407	-32882	-12355
2002	-1677882	812094	-865788	0	0	-865788	-875460	-88882	-30544	-11013
2003	-1794862	868713	-926149	0	0	-926149	-936401	-86426	-28406	-9816
2004	-1920002	929280	-990722	0	0	-990722	-1001589	-84039	-26457	-8749
2005	-2053872	994073	-1059799	0	0	-1059799	-1071318	-81718	-24608	-7799
2006	-2197081	1063387	-1133694	0	0	-1133694	-1145904	-79461	-22848	-6951
2007	-2350281	1137535	-1212746	0	0	-1212746	-1225689	-77267	-21248	-6196
2008	-2514169	1216857	-1297312	0	0	-1297312	-1311032	-75133	-19801	-5523
2009	-2689491	1301713	-1387778	0	0	-1387778	-1402321	-73059	-18417	-4923
2010	-2877046	1392490	-1484556	0	0	-1484556	-1499971	-71042	-17130	-4388
2011	-3077687	1489600	-1588087	0	0	-1588087	-1604427	-69081	-15933	-3911
2012	-3292328	1593486	-1698842	0	0	-1698842	-1716163	-67175	-14819	-3487
2013	-3521946	1704621	-1817325	0	0	-1817325	-1835685	-65321	-13744	-3108
2014	-3767586	1823511	-1944075	0	0	-1944075	-1963536	-63519	-12821	-2770
2015	-4030358	1950697	-2079661	0	0	-2079661	-1735854	-51049	-9856	-2041
TOTALS	-53646071	25964682	-27681391	0	0	-27681391	-27681393	-2885617	-1252241	-635581

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: GEISHAR COGENERATION
CASE : EXIST. PLANTS
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-63454	-63454	0	0	0	0	0	0
1986	0	0	-3807	-3807	-736494	-18577	0	0	0	-755071
1987	0	0	-4036	-4036	-788049	-19692	0	0	0	-807740
1988	0	0	-4278	-4278	-843212	-20873	0	0	0	-864085
1989	0	0	-4534	-4534	-902237	-22126	0	0	0	-924362
1990	0	0	-4807	-4807	-965393	-23453	0	0	0	-988846
1991	0	0	-5095	-5095	-1032971	-24860	0	0	0	-1057831
1992	0	0	-5401	-5401	-1105279	-26352	0	0	0	-1131631
1993	0	0	-5725	-5725	-1182648	-27933	0	0	0	-1210581
1994	0	0	-6068	-6068	-1265434	-29609	0	0	0	-1295043
1995	0	0	-6432	-6432	-1354014	-31385	0	0	0	-1385400
1996	0	0	-6818	-6818	-1448795	-33269	0	0	0	-1482064
1997	0	0	-7227	-7227	-1550211	-35265	0	0	0	-1585476
1998	0	0	-7661	-7661	-1658726	-37381	0	0	0	-1696106
1999	0	0	-8121	-8121	-1774837	-39623	0	0	0	-1814460
2000	0	0	-8608	-8608	-1899075	-42001	0	0	0	-1941076
2001	0	0	-9124	-9124	-2032010	-44521	0	0	0	-2076531
2002	0	0	-9672	-9672	-2174251	-47192	0	0	0	-2221443
2003	0	0	-10252	-10252	-2326449	-50024	0	0	0	-2376472
2004	0	0	-10867	-10867	-2489300	-53025	0	0	0	-2542325
2005	0	0	-11519	-11519	-2663551	-56207	0	0	0	-2719758
2006	0	0	-12210	-12210	-2850000	-59579	0	0	0	-2909579
2007	0	0	-12943	-12943	-3049500	-63154	0	0	0	-3112654
2008	0	0	-13720	-13720	-3262965	-66943	0	0	0	-3329908
2009	0	0	-14543	-14543	-3491372	-70959	0	0	0	-3562332
2010	0	0	-15415	-15415	-3735768	-75217	0	0	0	-3810986
2011	0	0	-16340	-16340	-3997272	-79730	0	0	0	-4077002
2012	0	0	-17321	-17321	-4277081	-84514	0	0	0	-4361595
2013	0	0	-18360	-18360	-4576477	-89585	0	0	0	-4666082
2014	0	0	-19461	-19461	-4896831	-94960	0	0	0	-4991790
2015	0	0	-343817	-343817	-5239609	-100657	0	0	0	-5340266
TOTALS	0	0	0	-2	-69569814	-1468664	0	0	0	-71038478

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GEISHAR COGENERATION
CASE : EXIST. PLANTS
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=,10)	(19) PRESENT WORTH=NCF (DR=,15)	(20) PRESENT WORTH=NCF (DR=,20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-63454	-32562	-23855	-17709
1986	-755071	365454	-389617	0	0	-389617	-393424	-183535	-128611	-91498
1987	-807740	390946	-416794	0	0	-416794	-420830	-178473	-119626	-81560
1988	-864085	418217	-445868	0	0	-445868	-450146	-173551	-111269	-72701
1989	-924362	447391	-476971	0	0	-476971	-481505	-168765	-103496	-64805
1990	-988846	478601	-510245	0	0	-510245	-515052	-164111	-96267	-57767
1991	-1057831	511990	-545841	0	0	-545841	-550936	-159587	-89543	-51493
1992	-1131631	547709	-583922	0	0	-583922	-589323	-155187	-83288	-45900
1993	-1210581	585921	-624660	0	0	-624660	-630385	-150909	-77471	-40915
1994	-1295043	626800	-668243	0	0	-668243	-674311	-146750	-72060	-36472
1995	-1385400	670533	-714867	0	0	-714867	-721299	-142705	-67027	-32511
1996	-1482064	717318	-764746	0	0	-764746	-771564	-138773	-62346	-28981
1997	-1585476	767370	-818106	0	0	-818106	-825333	-134949	-57992	-25834
1998	-1696106	820915	-875191	0	0	-875191	-882852	-131230	-53943	-23028
1999	-1814460	878198	-936262	0	0	-936262	-944383	-127615	-50176	-20528
2000	-1941076	939480	-1001596	0	0	-1001596	-1010204	-124100	-46672	-18299
2001	-2076531	1005041	-1071490	0	0	-1071490	-1080614	-120681	-43413	-16312
2002	-2221443	1075178	-1146265	0	0	-1146265	-1155937	-117357	-40382	-14541
2003	-2376472	1150212	-1226260	0	0	-1226260	-1236512	-114125	-37562	-12962
2004	-2542325	1230485	-1311840	0	0	-1311840	-1322707	-110982	-34940	-11555
2005	-2719758	1316362	-1403396	0	0	-1403396	-1414915	-107926	-32500	-10300
2006	-2909579	1408236	-1501343	0	0	-1501343	-1513553	-104955	-30231	-9182
2007	-3112654	1506524	-1606130	0	0	-1606130	-1619073	-102065	-28121	-8185
2008	-3329908	1611675	-1718233	0	0	-1718233	-1731953	-99256	-26158	-7296
2009	-3562332	1724168	-1838164	0	0	-1838164	-1852707	-96524	-24332	-6504
2010	-3810986	1844517	-1966469	0	0	-1966469	-1981884	-93867	-22633	-5798
2011	-4077002	1973269	-2103733	0	0	-2103733	-2120073	-91284	-21053	-5169
2012	-4361595	2111012	-2250583	0	0	-2250583	-2267904	-88771	-19584	-4607
2013	-4666062	2258373	-2407689	0	0	-2407689	-2426049	-86329	-18217	-4107
2014	-4991790	2416026	-2575764	0	0	-2575764	-2595225	-83953	-16945	-3661
2015	-5340266	2584686	-2755578	0	0	-2755578	-2411761	-70926	-13693	-2835
TOTALS	-71038478	34342609	-36655866	0	0	-36655866	-36655866	-3801788	-1651393	-832997

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APPENDIX C

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

Orange

PROJECT: CHARGE COGENERATION
CASE : EASTERN COAL
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,000)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,000)	(6) OTHER OPER EXPENSES (ER \$,000)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7316	0	0	-7316	0	0	-73	0	0	-73
1981	-9955	0	0	-9955	0	0	-237	0	0	-237
1982	-17263	0	0	-17263	0	0	-504	0	0	-504
1983	-114911	0	0	-114911	0	0	-1836	0	0	-1836
1984	-158102	0	0	-158102	0	0	-4603	0	0	-4603
1985	-134035	0	-10001	-144036	0	0	-7616	0	0	-7616
1986	0	0	-600	-600	-52229	-15168	-9109	-38985	47693	-67808
1987	0	0	-636	-636	-55363	-16078	-9109	-35520	51021	-65049
1988	0	0	-674	-674	-58685	-17043	-9109	-33848	54562	-64092
1989	0	0	-715	-715	-62206	-18065	-9109	-32197	58414	-63164
1990	0	0	-758	-758	-65938	-19149	-9109	-30546	62503	-62240
1991	0	0	-803	-803	-69894	-20298	-9109	-28895	66878	-61319
1992	0	0	-851	-851	-74088	-21516	-9109	-27244	71559	-60398
1993	0	0	-902	-902	-78533	-22807	-9109	-25593	76546	-59473
1994	0	0	-956	-956	-83245	-24175	-9109	-23942	81928	-58543
1995	0	0	-1014	-1014	-88240	-25626	-9109	-22290	87643	-57602
1996	0	0	-1075	-1075	-93534	-27164	-9109	-20639	93600	-56646
1997	0	0	-1139	-1139	-99146	-28793	-9109	-18988	100366	-55671
1998	0	0	-1207	-1207	-105095	-30521	-9109	-17337	107391	-54671
1999	0	0	-1280	-1280	-111401	-32352	-9109	-15686	114909	-53639
2000	0	0	-1357	-1357	-118085	-34293	-9109	-14035	122952	-52570
2001	0	0	-1438	-1438	-125170	-36351	-9109	-12384	131559	-51455
2002	0	0	-1524	-1524	-132680	-38532	-9109	-10732	140768	-50286
2003	0	0	-1616	-1616	-140641	-40844	-9109	-9081	150622	-49053
2004	0	0	-1713	-1713	-149079	-43295	-9109	-7430	161165	-47748
2005	0	0	-1816	-1816	-158024	-45892	-9109	-5779	172407	-46357
2006	0	0	-1924	-1924	-167505	-48646	-9109	-4128	184518	-44870
2007	0	0	-2040	-2040	-177556	-51565	-9109	-2477	197434	-43272
2008	0	0	-2162	-2162	-188209	-54658	-9109	-826	211255	-41547
2009	0	0	-2292	-2292	-199502	-57938	-9109	0	226043	-40506
2010	0	0	-2430	-2430	-211472	-61414	-9109	0	241866	-40129
2011	0	0	-2575	-2575	-224160	-65099	-9109	0	258796	-39572
2012	0	0	-2730	-2730	-237610	-69005	-9109	0	278912	-38812
2013	0	0	-2894	-2894	-251866	-73145	-9109	0	296266	-37825
2014	0	0	-3067	-3067	-266978	-77534	-9109	0	317037	-36585
2015	13257	0	54188	67446	-282997	-82186	-9109	0	335229	-35063
TOTALS	-427324	0	0	-427325	-4129130	-1199155	-288141	-438582	4504174	-1550834

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: ORANGE COGENERATION
CASE : EASTERN COAL
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWC)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1970	0	0	0	0	0	0	0	0	0	0
1980	-73	34	-39	0	531	491	-6824	-5640	-5160	-4739
1981	-237	109	-128	0	896	767	-8187	-6151	-5383	-4738
1982	-504	232	-272	0	1726	1453	-15809	-10798	-9019	-7624
1983	-1836	845	-991	0	11491	10499	-104411	-64831	-51911	-41960
1984	-4603	2117	-2486	0	15810	13323	-144778	-81723	-62592	-48486
1985	-7616	3504	-4112	0	13404	9291	-134744	-69145	-50655	-37605
1986	-67808	31191	-36617	38985	0	2367	1767	823	577	410
1987	-65049	29922	-35127	35520	0	392	-243	-103	-69	-47
1988	-64092	29482	-34610	33848	0	-762	-1436	-554	-355	-232
1989	-63164	29055	-34109	32197	0	-1912	-2627	-921	-565	-354
1990	-62240	28630	-33610	30546	0	-3064	-3822	-1216	-714	-429
1991	-61319	28206	-33113	28895	0	-4218	-5021	-1454	-816	-469
1992	-60398	27782	-32616	27244	0	-5372	-6223	-1639	-879	-485
1993	-59473	27357	-32116	25593	0	-6523	-7425	-1777	-912	-482
1994	-58543	26929	-31614	23942	0	-7672	-8628	-1878	-922	-467
1995	-57602	26496	-31106	22290	0	-8816	-9830	-1945	-913	-443
1996	-56646	26057	-30589	20639	0	-9950	-11025	-1983	-891	-414
1997	-55671	25606	-30063	18988	0	-11075	-12214	-1997	-858	-382
1998	-54671	25148	-29523	17337	0	-12186	-13393	-1991	-818	-349
1999	-53639	24674	-28965	15686	0	-13279	-14559	-1967	-774	-316
2000	-52570	24192	-28368	14035	0	-14353	-15710	-1930	-726	-285
2001	-51455	23669	-27786	12384	0	-15402	-16840	-1881	-677	-254
2002	-50286	23131	-27155	10732	0	-16423	-17947	-1822	-627	-226
2003	-49053	22564	-26489	9081	0	-17468	-19024	-1756	-578	-199
2004	-47748	21963	-25785	7430	0	-18355	-20068	-1684	-530	-175
2005	-46357	21324	-25033	5779	0	-19254	-21070	-1607	-484	-153
2006	-44870	20640	-24230	4128	0	-20102	-22026	-1527	-440	-134
2007	-43272	19904	-23368	2477	0	-20891	-22931	-1446	-398	-116
2008	-41547	19111	-22436	826	0	-21610	-23772	-1362	-359	-100
2009	-40506	18632	-21874	0	0	-21874	-24166	-1259	-317	-85
2010	-40129	18459	-21670	0	0	-21670	-24100	-1141	-275	-71
2011	-39572	18203	-21369	0	0	-21369	-23944	-1031	-238	-58
2012	-38812	17853	-20959	0	0	-20959	-23689	-927	-205	-48
2013	-37825	17399	-20426	0	0	-20426	-23320	-830	-175	-39
2014	-36585	16829	-19756	0	0	-19756	-22823	-738	-149	-32
2015	-35063	16128	-18935	0	0	-18935	-48510	-1426	-274	-56
TOTALS	-1550834	713369	-837465	438582	43858	-355025	-782352	-276386	-196534	-151510

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASH : EASTERN COAL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7316	0	0	-7316	0	0	-73	0	0	-73
1981	-8955	0	0	-8955	0	0	-237	0	0	-237
1982	-17263	0	0	-17263	0	0	-504	0	0	-504
1983	-114911	0	0	-114911	0	0	-1836	0	0	-1836
1984	-158102	0	0	-158102	0	0	-4603	0	0	-4603
1985	-134035	0	-10001	-144036	0	0	-7616	0	0	-7616
1986	0	0	-600	-600	-58032	-15168	-9109	-38925	47683	-73611
1987	0	0	-636	-636	-61514	-16078	-9109	-35520	51021	-71200
1988	0	0	-674	-674	-65205	-17043	-9109	-33848	54592	-70613
1989	0	0	-715	-715	-69117	-18065	-9109	-32197	58414	-70075
1990	0	0	-758	-758	-73264	-19149	-9109	-30546	62503	-69566
1991	0	0	-803	-803	-77660	-20298	-9109	-28895	66878	-69084
1992	0	0	-851	-851	-82320	-21516	-9109	-27244	71559	-68629
1993	0	0	-902	-902	-87259	-22807	-9109	-25593	76568	-68199
1994	0	0	-956	-956	-92494	-24175	-9109	-23942	81928	-67792
1995	0	0	-1014	-1014	-98044	-25626	-9109	-22290	87663	-67406
1996	0	0	-1075	-1075	-103926	-27164	-9109	-20639	93800	-67039
1997	0	0	-1139	-1139	-110162	-28793	-9109	-18988	100366	-66687
1998	0	0	-1207	-1207	-116772	-30521	-9109	-17337	107391	-66348
1999	0	0	-1280	-1280	-123778	-32352	-9109	-15686	114909	-66017
2000	0	0	-1357	-1357	-131205	-34293	-9109	-14035	122952	-65690
2001	0	0	-1438	-1438	-139077	-36351	-9109	-12384	131559	-65362
2002	0	0	-1524	-1524	-147422	-38532	-9109	-10732	140768	-65027
2003	0	0	-1616	-1616	-156267	-40844	-9109	-9081	150622	-64680
2004	0	0	-1713	-1713	-165643	-43295	-9109	-7430	161165	-64311
2005	0	0	-1816	-1816	-175582	-45892	-9109	-5779	172447	-63915
2006	0	0	-1924	-1924	-186116	-48646	-9109	-4128	184518	-63481
2007	0	0	-2040	-2040	-197283	-51565	-9109	-2477	197434	-62999
2008	0	0	-2162	-2162	-209120	-54658	-9109	-826	211255	-62459
2009	0	0	-2292	-2292	-221668	-57938	-9109	0	226043	-62672
2010	0	0	-2430	-2430	-234968	-61414	-9109	0	241866	-63625
2011	0	0	-2575	-2575	-249066	-65099	-9109	0	258796	-64478
2012	0	0	-2730	-2730	-264010	-69005	-9109	0	276912	-65212
2013	0	0	-2894	-2894	-279850	-73145	-9109	0	296296	-65809
2014	0	0	-3067	-3067	-296641	-77534	-9109	0	317037	-66248
2015	13257	0	54188	67446	-314440	-82186	-9109	0	335229	-66506
TOTALS	-427324	0	0	-427325	-4587905	-1199155	-288141	-436582	4504174	-2009609

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: ORANGE COGENERATION
CASE : EASTERN COAL
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-73	34	-39	0	531	491	-6824	-5640	-5160	-4739
1981	-237	109	-128	0	896	767	-8187	-6151	-5323	-4738
1982	-504	232	-272	0	1726	1453	-15809	-10798	-9019	-7624
1983	-1836	845	-991	0	11491	10499	-104411	-64831	-51911	-41940
1984	-4803	2117	-2686	0	15810	13323	-144778	-81723	-62592	-48486
1985	-7516	3504	-4112	0	13404	9291	-134744	-69145	-50655	-37605
1986	-73011	33861	-39750	38985	0	-765	-1365	-637	-486	-317
1987	-71200	32751	-38449	35520	0	-2929	-3565	-1512	-1013	-691
1988	-70613	32481	-38132	33848	0	-4224	-4958	-1912	-1226	-801
1989	-70075	32234	-37841	32197	0	-5644	-6359	-2229	-1347	-856
1990	-69566	32000	-37566	30546	0	-7020	-7778	-2478	-1454	-872
1991	-69084	31778	-37306	28895	0	-8411	-9214	-2669	-1498	-861
1992	-68629	31569	-37060	27244	0	-9816	-10667	-2809	-1508	-831
1993	-68199	31371	-36828	25593	0	-11235	-12137	-2906	-1462	-788
1994	-67792	31184	-36608	23942	0	-12666	-13622	-2965	-1456	-737
1995	-67406	31006	-36400	22290	0	-14110	-15124	-2992	-1405	-682
1996	-67039	30837	-36202	20639	0	-15563	-16638	-2992	-1304	-625
1997	-66687	30676	-36011	18988	0	-17023	-18162	-2970	-1276	-568
1998	-66348	30519	-35829	17337	0	-18492	-19699	-2928	-1204	-514
1999	-66017	30367	-35650	15686	0	-19964	-21244	-2871	-1129	-462
2000	-65690	30217	-35473	14035	0	-21438	-22795	-2800	-1053	-413
2001	-65362	30066	-35296	12384	0	-22912	-24350	-2719	-978	-368
2002	-65027	29912	-35115	10732	0	-24383	-25907	-2630	-905	-326
2003	-64680	29752	-34928	9081	0	-25847	-27463	-2535	-814	-288
2004	-64311	29583	-34728	7430	0	-27298	-29011	-2434	-766	-253
2005	-63915	29400	-34515	5779	0	-28736	-30552	-2330	-702	-222
2006	-63481	29201	-34280	4128	0	-30152	-32076	-2224	-641	-195
2007	-62999	28979	-34020	2477	0	-31543	-33583	-2117	-583	-170
2008	-62459	28730	-33729	826	0	-32903	-35065	-2010	-530	-148
2009	-62072	28429	-33643	0	0	-33843	-36135	-1883	-475	-127
2010	-61625	28267	-33358	0	0	-34358	-36788	-1742	-420	-108
2011	-61208	28059	-33149	0	0	-34819	-37390	-1610	-371	-91
2012	-60812	27897	-32915	0	0	-35215	-37945	-1485	-328	-77
2013	-60439	27722	-32657	0	0	-35537	-38431	-1368	-289	-65
2014	-60088	27544	-32344	0	0	-35774	-38841	-1256	-254	-55
2015	-60506	27592	-32914	0	0	-35914	-31531	926	178	36
TOTALS	-2009609	924405	-1085204	438582	43858	-602764	-1030090	-303356	-211487	-157600

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EASTERN DUAL
150X FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7316	0	0	-7316	0	0	-73	0	0	-73
1981	-8955	0	0	-8955	0	0	-237	0	0	-237
1982	-17263	0	0	-17263	0	0	-504	0	0	-504
1983	-114911	0	0	-114911	0	0	-1836	0	0	-1836
1984	-158102	0	0	-158102	0	0	-4603	0	0	-4603
1985	-134035	0	-10001	-144036	0	0	-7616	0	0	-7616
1986	0	0	-600	-600	-87048	-15168	-9109	-38995	47683	-102627
1987	0	0	-636	-636	-92271	-16078	-9109	-35520	51021	-101957
1988	0	0	-674	-674	-97807	-17043	-9109	-33848	54592	-103215
1989	0	0	-715	-715	-103676	-18065	-9109	-32197	58414	-104634
1990	0	0	-758	-758	-109896	-19149	-9109	-30546	62503	-106198
1991	0	0	-803	-803	-116490	-20298	-9109	-28895	66878	-107914
1992	0	0	-851	-851	-123479	-21516	-9109	-27244	71569	-109789
1993	0	0	-902	-902	-130888	-22807	-9109	-25593	76568	-111828
1994	0	0	-956	-956	-138741	-24175	-9109	-23942	81928	-114039
1995	0	0	-1014	-1014	-147066	-25626	-9109	-22290	87663	-116428
1996	0	0	-1075	-1075	-155890	-27164	-9109	-20639	93800	-119002
1997	0	0	-1139	-1139	-165243	-28793	-9109	-18988	100346	-121768
1998	0	0	-1207	-1207	-175158	-30521	-9109	-17337	107361	-124733
1999	0	0	-1280	-1280	-185667	-32352	-9109	-15686	114969	-127906
2000	0	0	-1357	-1357	-196807	-34293	-9109	-14035	122962	-131292
2001	0	0	-1438	-1438	-208616	-36351	-9109	-12384	131569	-134900
2002	0	0	-1524	-1524	-221133	-38532	-9109	-10732	140768	-138738
2003	0	0	-1616	-1616	-234400	-40844	-9109	-9081	150692	-142813
2004	0	0	-1713	-1713	-248465	-43295	-9109	-7430	161165	-147133
2005	0	0	-1816	-1816	-263372	-45892	-9109	-5779	172407	-151706
2006	0	0	-1924	-1924	-279175	-48646	-9109	-4128	184518	-156539
2007	0	0	-2040	-2040	-295925	-51565	-9109	-2477	197414	-161641
2008	0	0	-2162	-2162	-313681	-54658	-9109	-826	211255	-167019
2009	0	0	-2292	-2292	-332502	-57938	-9109	0	226003	-173506
2010	0	0	-2430	-2430	-352452	-61414	-9109	0	241846	-181109
2011	0	0	-2575	-2575	-373599	-65099	-9109	0	258706	-189011
2012	0	0	-2730	-2730	-396015	-69005	-9109	0	276912	-197217
2013	0	0	-2894	-2894	-419776	-73145	-9109	0	296266	-205734
2014	0	0	-3067	-3067	-444962	-77534	-9109	0	317017	-214569
2015	13257	0	54188	67446	-471660	-82186	-9109	0	339229	-223726
TOTALS	-427324	0	0	-427325	-6881857	-1199155	-288141	-438582	4504174	-4303561

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EASTERN COAL
15% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-73	34	-39	0	531	491	-6824	-5640	-5160	-4739
1981	-237	109	-128	0	896	767	-8187	-6151	-5383	-4738
1982	-504	232	-272	0	1726	1453	-15809	-10798	-9039	-7624
1983	-1836	845	-991	0	11491	10499	-104411	-64831	-51911	-41960
1984	-4603	2117	-2486	0	15810	13323	-144778	-81723	-62592	-48486
1985	-7616	3504	-4112	0	13404	9291	-134744	-69145	-50655	-37605
1986	-102627	47208	-55419	38985	0	-16434	-17034	-7946	-5568	-3962
1987	-101957	46900	-55057	35520	0	-19537	-20173	-8555	-5734	-3910
1988	-103215	47478	-55737	33848	0	-21889	-22563	-8699	-5577	-3644
1989	-104634	48131	-56503	32197	0	-24306	-25021	-8770	-5378	-3368
1990	-106198	48851	-57347	30546	0	-26801	-27559	-8781	-5151	-3091
1991	-107914	49640	-58274	28845	0	-29379	-30182	-8743	-4905	-2821
1992	-109789	50502	-59287	27244	0	-32043	-32894	-8662	-4649	-2562
1993	-111928	51441	-60387	25593	0	-34794	-35696	-8545	-4387	-2317
1994	-114039	52458	-61581	23942	0	-37639	-38595	-8399	-4124	-2088
1995	-116428	53556	-62872	22290	0	-40582	-41596	-8230	-3865	-1875
1996	-119002	54740	-64262	20639	0	-43623	-44698	-8039	-3612	-1679
1997	-121768	56013	-65755	18988	0	-46767	-47906	-7833	-3366	-1499
1998	-124733	57377	-67356	17337	0	-50019	-51226	-7614	-3130	-1336
1999	-127906	58836	-69070	15686	0	-53384	-54664	-7387	-2904	-1188
2000	-131292	60394	-70898	14035	0	-56863	-58220	-7152	-2690	-1055
2001	-134900	62054	-72846	12384	0	-60462	-61900	-6913	-2487	-934
2002	-138738	63819	-74919	10732	0	-64187	-65711	-6671	-2296	-827
2003	-142813	65693	-77120	9081	0	-68039	-69655	-6429	-2116	-730
2004	-147133	67681	-79452	7430	0	-72022	-73735	-6187	-1948	-644
2005	-151706	69784	-81922	5779	0	-76143	-77959	-5947	-1791	-568
2006	-156539	72008	-84531	4128	0	-80403	-82327	-5709	-1644	-499
2007	-161641	74354	-87287	2477	0	-84810	-86850	-5475	-1508	-439
2008	-167019	76828	-90191	826	0	-89365	-91527	-5245	-1382	-386
2009	-173506	79812	-93694	0	0	-93694	-95986	-5001	-1261	-337
2010	-181109	83310	-97799	0	0	-97799	-100229	-4747	-1145	-293
2011	-189011	86944	-102067	0	0	-102067	-104642	-4506	-1039	-255
2012	-197217	90719	-106498	0	0	-106498	-109228	-4275	-943	-222
2013	-205734	94637	-111097	0	0	-111097	-113991	-4056	-856	-193
2014	-214569	98701	-115868	0	0	-115868	-118935	-3847	-777	-168
2015	-223726	102913	-120813	0	0	-120813	-53367	-1569	-383	-63
TOTALS	-4303561	1979623	-2323937	439582	43858	-1841497	-2268822	-438205	-271257	-188082

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHANGE COGENERATION
CASE : EASTERN COAL
200% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER MAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7316	0	0	-7316	0	0	-73	0	0	-73
1981	-8955	0	0	-8955	0	0	-237	0	0	-237
1982	-17263	0	0	-17263	0	0	-504	0	0	-504
1983	-114911	0	0	-114911	0	0	-1836	0	0	-1836
1984	-158102	0	0	-158102	0	0	-4603	0	0	-4603
1985	-134035	0	-10001	-144036	0	0	-7616	0	0	-7616
1986	0	0	-600	-600	-116064	-15168	-9109	-38985	47683	-131643
1987	0	0	-636	-636	-123028	-16078	-9109	-35520	51021	-132714
1988	0	0	-674	-674	-130410	-17043	-9109	-33848	54592	-135817
1989	0	0	-715	-715	-138234	-18065	-9109	-32197	58414	-139192
1990	0	0	-758	-758	-146528	-19149	-9109	-30546	62503	-142830
1991	0	0	-803	-803	-155320	-20298	-9109	-28895	66878	-146744
1992	0	0	-851	-851	-164639	-21516	-9109	-27244	71559	-150949
1993	0	0	-902	-902	-174517	-22807	-9109	-25593	76568	-155458
1994	0	0	-956	-956	-184988	-24175	-9109	-23942	81928	-160286
1995	0	0	-1014	-1014	-196088	-25626	-9109	-22290	87663	-165450
1996	0	0	-1075	-1075	-207853	-27164	-9109	-20639	93800	-170965
1997	0	0	-1139	-1139	-220324	-28793	-9109	-18988	100366	-176849
1998	0	0	-1207	-1207	-233544	-30521	-9109	-17337	107391	-183119
1999	0	0	-1280	-1280	-247556	-32352	-9109	-15686	114909	-189795
2000	0	0	-1357	-1357	-262410	-34293	-9109	-14035	122952	-196894
2001	0	0	-1438	-1438	-278154	-36351	-9109	-12384	131559	-204439
2002	0	0	-1524	-1524	-294843	-38532	-9109	-10732	140768	-212449
2003	0	0	-1616	-1616	-312534	-40844	-9109	-9081	150622	-220946
2004	0	0	-1713	-1713	-331286	-43295	-9109	-7430	161165	-229955
2005	0	0	-1816	-1816	-351163	-45892	-9109	-5779	172447	-239497
2006	0	0	-1924	-1924	-372233	-48646	-9109	-4128	184518	-249598
2007	0	0	-2040	-2040	-394567	-51565	-9109	-2477	197434	-260283
2008	0	0	-2162	-2162	-418241	-54658	-9109	-826	211255	-271579
2009	0	0	-2292	-2292	-443335	-57938	-9109	0	226043	-284340
2010	0	0	-2430	-2430	-469936	-61414	-9109	0	241866	-298593
2011	0	0	-2575	-2575	-498132	-65099	-9109	0	258796	-313544
2012	0	0	-2730	-2730	-528020	-69005	-9109	0	276912	-329222
2013	0	0	-2894	-2894	-559701	-73145	-9109	0	296296	-345659
2014	0	0	-3067	-3067	-593283	-77534	-9109	0	317037	-362889
2015	13257	0	54188	67446	-628880	-82186	-9109	0	339229	-380946
TOTALS	-427324	0	0	-427325	-9175810	-1199155	-288141	-438582	4504174	-6597513

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EASTERN COAL
200% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FIVE)	(12) INCOME TAXES (-.46+11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10+1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-73	34	-39	0	531	491	-6824	-5640	-5160	-4739
1981	-237	109	-128	0	896	767	-8187	-6151	-5383	-4738
1982	-504	232	-272	0	1726	1453	-15809	-10798	-9039	-7624
1983	-1434	845	-991	0	11491	10499	-104411	-64831	-51911	-41960
1984	-4403	2117	-2486	0	15810	13323	-144778	-81723	-62592	-48486
1985	-7616	3504	-4112	0	13404	9291	-134744	-69145	-50655	-37605
1986	-131643	60555	-71088	38985	0	-32103	-32703	-15256	-10691	-7606
1987	-132714	61048	-71666	35520	0	-36146	-36782	-15599	-10466	-7129
1988	-135817	62476	-73341	33848	0	-39493	-40167	-15486	-9959	-6487
1989	-139192	64028	-75164	32197	0	-42967	-43682	-15310	-9369	-5879
1990	-142830	65701	-77129	30546	0	-46583	-47341	-15084	-8848	-5310
1991	-146744	67502	-79242	28895	0	-50347	-51150	-14816	-8313	-4781
1992	-150949	69436	-81513	27244	0	-54269	-55120	-14515	-7760	-4293
1993	-155458	71510	-83948	25593	0	-58355	-59257	-14186	-7282	-3846
1994	-160256	73731	-86555	23942	0	-62613	-63569	-13834	-6763	-3438
1995	-165450	76106	-89344	22290	0	-67054	-68068	-13467	-6325	-3068
1996	-170965	78643	-92322	20639	0	-71683	-72758	-13086	-5879	-2733
1997	-176849	81350	-95499	18988	0	-76511	-77650	-12696	-5466	-2431
1998	-183119	84234	-98885	17337	0	-81548	-82755	-12301	-5066	-2159
1999	-189795	87305	-102490	15686	0	-86804	-88084	-11903	-4680	-1915
2000	-196894	90571	-106323	14035	0	-92288	-93645	-11504	-4326	-1696
2001	-204439	94041	-110398	12364	0	-98014	-99452	-11107	-3965	-1501
2002	-212449	97726	-114723	10732	0	-103991	-105515	-10712	-3686	-1327
2003	-220946	101635	-119311	9081	0	-110230	-111846	-10323	-3398	-1172
2004	-229955	105779	-124176	7430	0	-116746	-118459	-9939	-3129	-1035
2005	-239497	110168	-129329	5779	0	-123550	-125366	-9563	-2880	-913
2006	-249598	114814	-134784	4128	0	-130656	-132580	-9194	-2608	-804
2007	-260283	119730	-140553	2477	0	-138076	-140116	-8833	-2454	-708
2008	-271579	124926	-146653	826	0	-145827	-147989	-8481	-2235	-623
2009	-283440	130796	-153544	0	0	-153544	-155836	-8119	-2047	-547
2010	-295853	137352	-161241	0	0	-161241	-163671	-7752	-1869	-479
2011	-308844	144230	-169314	0	0	-169314	-171889	-7401	-1767	-419
2012	-322422	151441	-177781	0	0	-177781	-180511	-7066	-1569	-367
2013	-336659	159003	-186656	0	0	-186656	-189550	-6745	-1423	-321
2014	-351549	166929	-195560	0	0	-195560	-199027	-6438	-1300	-281
2015	-367046	175235	-205711	0	0	-205711	-209665	-6066	-1185	-163
TOTALS	-6597513	3034842	-3562671	438582	43856	-3080231	-3507556	-573052	-331033	-218563

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7350	0	0	-7350	0	0	-74	0	0	-74
1981	-9020	0	0	-9020	0	0	-239	0	0	-239
1982	-17407	0	0	-17407	0	0	-508	0	0	-508
1983	-115851	0	0	-115851	0	0	-1851	0	0	-1851
1984	-159363	0	0	-159363	0	0	-4640	0	0	-4640
1985	-135099	0	-10988	-146087	0	0	-7677	0	0	-7677
1986	0	0	-659	-659	-57391	-14116	-9182	-39298	47683	-72303
1987	0	0	-699	-699	-60834	-14963	-9182	-35805	51021	-69763
1988	0	0	-741	-741	-64485	-15861	-9182	-34120	54592	-69055
1989	0	0	-785	-785	-68354	-16812	-9182	-32455	58414	-68389
1990	0	0	-832	-832	-72455	-17821	-9182	-30791	62503	-67746
1991	0	0	-882	-882	-76802	-18890	-9182	-29127	66878	-67123
1992	0	0	-935	-935	-81410	-20024	-9182	-27462	71559	-66519
1993	0	0	-991	-991	-86295	-21225	-9182	-25798	76568	-65931
1994	0	0	-1051	-1051	-91473	-22499	-9182	-24134	81928	-65358
1995	0	0	-1114	-1114	-96961	-23849	-9182	-22469	87663	-64797
1996	0	0	-1181	-1181	-102779	-25280	-9182	-20805	93800	-64245
1997	0	0	-1252	-1252	-106945	-26796	-9182	-19140	100366	-63698
1998	0	0	-1327	-1327	-115482	-28404	-9182	-17476	107391	-63153
1999	0	0	-1406	-1406	-122411	-30108	-9182	-15812	114909	-62604
2000	0	0	-1491	-1491	-129756	-31915	-9182	-14147	122952	-62047
2001	0	0	-1580	-1580	-137541	-33830	-9182	-12483	131559	-61476
2002	0	0	-1675	-1675	-145793	-35860	-9182	-10818	140768	-60885
2003	0	0	-1775	-1775	-154541	-38011	-9182	-9154	150622	-60266
2004	0	0	-1882	-1882	-163813	-40292	-9182	-7490	161165	-59611
2005	0	0	-1995	-1995	-173642	-42709	-9182	-5825	172447	-58912
2006	0	0	-2114	-2114	-184061	-45272	-9182	-4161	184518	-58157
2007	0	0	-2241	-2241	-195104	-47988	-9182	-2457	197434	-57336
2008	0	0	-2376	-2376	-206811	-50868	-9182	-832	211255	-56437
2009	0	0	-2518	-2518	-219219	-53920	-9182	0	226043	-56278
2010	0	0	-2669	-2669	-232372	-57155	-9182	0	241866	-56843
2011	0	0	-2830	-2830	-246315	-60584	-9182	0	258796	-57284
2012	0	0	-2999	-2999	-261094	-64219	-9182	0	276912	-57582
2013	0	0	-3179	-3179	-276759	-68072	-9182	0	296296	-57717
2014	0	0	-3370	-3370	-293365	-72157	-9182	0	317037	-57667
2015	13257	0	59536	72794	-310967	-76486	-9182	0	339229	-57405
TOTALS	-430841	0	0	-430842	-4537229	-1115985	-290440	-442099	4504174	-1881578

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (CR=.10)	(19) PRESENT WORTH=NCF (CR=.15)	(20) PRESENT WORTH=NCF (CR=.20)
1970	0	0	0	0	0	0	0	0	0	0
1980	-74	34	-40	0	534	493	-6856	-5666	-5184	-4761
1981	-239	110	-129	0	903	773	-8255	-6202	-5428	-4777
1982	-508	234	-274	0	1741	1466	-15940	-10887	-9114	-7687
1983	-1851	851	-1000	0	11585	10584	-105266	-65362	-52336	-42304
1984	-4640	2134	-2506	0	15936	13429	-145933	-82375	-63091	-48873
1985	-7677	3532	-4145	0	13510	9364	-136722	-70160	-51349	-38157
1986	-72303	33259	-39044	39298	0	253	-405	-189	-132	-94
1987	-69763	32090	-37673	35805	0	-1868	-2567	-1089	-730	-498
1988	-69055	31765	-37290	34120	0	-3170	-3911	-1508	-967	-632
1989	-68389	31459	-36930	32455	0	-4475	-5260	-1844	-1131	-708
1990	-67746	31163	-36583	30791	0	-5792	-6624	-2111	-1238	-743
1991	-67123	30876	-36247	29127	0	-7120	-8002	-2318	-1361	-748
1992	-66519	30596	-35923	27462	0	-8459	-9394	-2474	-1328	-732
1993	-65931	30328	-35603	25798	0	-9805	-10796	-2584	-1327	-701
1994	-65358	30064	-35294	24134	0	-11160	-12211	-2657	-1365	-660
1995	-64797	29806	-34991	22469	0	-12522	-13636	-2698	-1267	-615
1996	-64245	29552	-34693	20805	0	-13888	-15069	-2710	-1218	-566
1997	-63698	29301	-34397	19140	0	-15257	-16509	-2699	-1160	-517
1998	-63153	29050	-34103	17476	0	-16627	-17954	-2669	-1097	-468
1999	-62604	28797	-33807	15812	0	-17995	-19401	-2622	-1031	-422
2000	-62047	28541	-33506	14147	0	-19359	-20850	-2561	-963	-378
2001	-61476	28279	-33197	12483	0	-20714	-22294	-2490	-896	-337
2002	-60885	28007	-32878	10818	0	-22060	-23735	-2410	-829	-299
2003	-60266	27722	-32544	9154	0	-23390	-25165	-2323	-764	-264
2004	-59611	27421	-32190	7490	0	-24700	-26582	-2230	-702	-232
2005	-58912	27099	-31813	5825	0	-25988	-27983	-2134	-643	-204
2006	-58157	26752	-31405	4161	0	-27244	-29358	-2036	-586	-178
2007	-57336	26374	-30962	2497	0	-28465	-30706	-1936	-533	-155
2008	-56437	25961	-30476	832	0	-29644	-32020	-1835	-484	-135
2009	-56278	25887	-30391	0	0	-30391	-32909	-1715	-432	-116
2010	-56843	26147	-30696	0	0	-30696	-33365	-1580	-381	-98
2011	-57284	26350	-30934	0	0	-30934	-33764	-1454	-335	-82
2012	-57582	26487	-31095	0	0	-31095	-34094	-1335	-294	-69
2013	-57717	26549	-31168	0	0	-31168	-34347	-1222	-258	-58
2014	-57667	26526	-31141	0	0	-31141	-34511	-1116	-225	-49
2015	-57405	26406	-30999	0	0	-30999	-41794	-1228	-236	-48
TOTALS	-1881578	865511	-1016065	442099	44209	-529757	-960600	-297952	-209862	-157246

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHARGE COGENERATION
CASE : WESTERN COAL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) PACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,000)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7350	0	0	-7350	0	0	-74	0	0	-74
1981	-9029	0	0	-9029	0	0	-239	0	0	-239
1982	-17407	0	0	-17407	0	0	-508	0	0	-508
1983	-115851	0	0	-115851	0	0	-1851	0	0	-1851
1984	-159363	0	0	-159363	0	0	-4640	0	0	-4640
1985	-135099	0	-10988	-146087	0	0	-7677	0	0	-7677
1986	0	0	-659	-659	-63768	-14116	-9182	-39298	47683	-78680
1987	0	0	-699	-699	-67594	-14963	-9182	-35805	51021	-76523
1988	0	0	-741	-741	-71650	-15861	-9182	-34120	54592	-76220
1989	0	0	-785	-785	-75949	-16812	-9182	-32455	58414	-75985
1990	0	0	-832	-832	-80506	-17821	-9182	-30791	62503	-75797
1991	0	0	-882	-882	-85336	-18890	-9182	-29127	66878	-75657
1992	0	0	-935	-935	-90456	-20024	-9182	-27462	71559	-75565
1993	0	0	-991	-991	-95883	-21225	-9182	-25798	76568	-75520
1994	0	0	-1051	-1051	-101637	-22499	-9182	-24134	81928	-75522
1995	0	0	-1114	-1114	-107735	-23849	-9182	-22469	87683	-75571
1996	0	0	-1181	-1181	-114199	-25280	-9182	-20805	93880	-75665
1997	0	0	-1252	-1252	-121051	-26796	-9182	-19140	100386	-75804
1998	0	0	-1327	-1327	-128314	-28404	-9182	-17476	107391	-75984
1999	0	0	-1406	-1406	-136013	-30108	-9182	-15812	114909	-76206
2000	0	0	-1491	-1491	-144173	-31915	-9182	-14147	122952	-76465
2001	0	0	-1580	-1580	-152824	-33830	-9182	-12483	131559	-76759
2002	0	0	-1675	-1675	-161993	-35860	-9182	-10818	140768	-77085
2003	0	0	-1775	-1775	-171713	-38011	-9182	-9154	150622	-77438
2004	0	0	-1882	-1882	-182016	-40292	-9182	-7490	161165	-77813
2005	0	0	-1995	-1995	-192936	-42709	-9182	-5825	172407	-78206
2006	0	0	-2114	-2114	-204513	-45272	-9182	-4161	184518	-78609
2007	0	0	-2241	-2241	-216783	-47988	-9182	-2497	197434	-79015
2008	0	0	-2376	-2376	-229790	-50868	-9182	-832	211255	-79417
2009	0	0	-2518	-2518	-243578	-53920	-9182	0	226043	-80636
2010	0	0	-2669	-2669	-258192	-57155	-9182	0	241886	-82663
2011	0	0	-2830	-2830	-273684	-60584	-9182	0	258796	-84653
2012	0	0	-2999	-2999	-290105	-64219	-9182	0	276912	-86594
2013	0	0	-3179	-3179	-307511	-68072	-9182	0	296296	-88469
2014	0	0	-3370	-3370	-325962	-72157	-9182	0	317037	-90264
2015	13257	0	59536	72794	-345520	-76486	-9182	0	339229	-91958
TOTALS	-430841	0	0	-430842	-5041383	-1115985	-290440	-442099	4504174	-2385733

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
100% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-74	34	-40	0	534	493	-6856	-5666	-5184	-4761
1981	-239	110	-129	0	903	773	-8255	-6202	-5428	-4777
1982	-508	234	-274	0	1741	1466	-15940	-10887	-9114	-7687
1983	-1851	851	-1000	0	11585	10584	-105266	-65362	-52316	-42304
1984	-4640	2134	-2506	0	15936	13429	-145933	-82375	-63091	-48873
1985	-7677	3532	-4145	0	13510	9364	-136722	-70160	-51399	-38157
1986	-78680	36192	-42488	39298	0	-3190	-3849	-1796	-1258	-895
1987	-76523	35200	-41323	35805	0	-5518	-6217	-2637	-1767	-1205
1988	-76220	35061	-41159	34120	0	-7039	-7780	-3000	-1973	-1257
1989	-75985	34952	-41033	32455	0	-8578	-9363	-3282	-2013	-1260
1990	-75797	34866	-40931	30791	0	-10140	-10972	-3496	-2051	-1231
1991	-75657	34802	-40855	29127	0	-11728	-12610	-3653	-2049	-1179
1992	-75565	34759	-40806	27462	0	-13344	-14279	-3760	-2018	-1112
1993	-75520	34739	-40781	25798	0	-14983	-15974	-3824	-1963	-1037
1994	-75522	34740	-40782	24134	0	-16648	-17699	-3852	-1891	-957
1995	-75571	34762	-40809	22469	0	-18340	-19454	-3849	-1808	-877
1996	-75665	34806	-40859	20805	0	-20054	-21235	-3819	-1716	-798
1997	-75804	34869	-40935	19140	0	-21795	-23047	-3768	-1619	-721
1998	-75984	34952	-41032	17476	0	-23556	-24883	-3699	-1520	-649
1999	-76206	35054	-41152	15812	0	-25340	-26746	-3614	-1421	-581
2000	-76465	35173	-41292	14147	0	-27145	-28636	-3518	-1323	-519
2001	-76759	35309	-41450	12483	0	-28967	-30547	-3411	-1227	-461
2002	-77085	35459	-41626	10818	0	-30808	-32483	-3298	-1135	-409
2003	-77438	35621	-41817	9154	0	-32663	-34438	-3178	-1046	-361
2004	-77813	35794	-42019	7490	0	-34529	-36411	-3055	-962	-318
2005	-78206	35974	-42232	5825	0	-36407	-38402	-2929	-882	-280
2006	-78609	36160	-42449	4161	0	-38288	-40402	-2802	-807	-245
2007	-79015	36347	-42668	2497	0	-40171	-42412	-2674	-737	-214
2008	-79417	36531	-42886	832	0	-42054	-44430	-2546	-671	-187
2009	-80836	37092	-43544	0	0	-43544	-46062	-2400	-605	-162
2010	-82663	38025	-44638	0	0	-44638	-47307	-2241	-540	-138
2011	-84653	38940	-45713	0	0	-45713	-48543	-2090	-482	-118
2012	-86594	39833	-46761	0	0	-46761	-49760	-1948	-430	-101
2013	-88469	40695	-47774	0	0	-47774	-50953	-1813	-383	-86
2014	-90264	41521	-48743	0	0	-48743	-52113	-1686	-340	-74
2015	-91958	42300	-49658	0	0	-49658	-53135	-1579	-300	-62
TOTALS	-2345733	1097423	-1288309	442099	44209	-802001	-1232844	-327592	-222991	-163949

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
150% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7350	0	0	-7350	0	0	-74	0	0	-74
1981	-9029	0	0	-9029	0	0	-239	0	0	-239
1982	-17407	0	0	-17407	0	0	-508	0	0	-508
1983	-115851	0	0	-115851	0	0	-1851	0	0	-1851
1984	-159363	0	0	-159363	0	0	-4640	0	0	-4640
1985	-135099	0	-10988	-146087	0	0	-7677	0	0	-7677
1986	0	0	-659	-659	-95652	-14116	-9182	-39298	476P3	-110564
1987	0	0	-699	-699	-101391	-14963	-9182	-35805	51021	-110320
1988	0	0	-741	-741	-107475	-15861	-9182	-34120	54592	-112045
1989	0	0	-785	-785	-113923	-16812	-9182	-32455	58414	-113959
1990	0	0	-832	-832	-120758	-17821	-9182	-30791	62503	-116050
1991	0	0	-882	-882	-128004	-18890	-9182	-29127	66878	-118325
1992	0	0	-935	-935	-135684	-20024	-9182	-27462	71559	-120793
1993	0	0	-991	-991	-143825	-21225	-9182	-25798	76568	-123462
1994	0	0	-1051	-1051	-152455	-22499	-9182	-24134	81928	-126341
1995	0	0	-1114	-1114	-161602	-23849	-9182	-22469	87663	-129438
1996	0	0	-1181	-1181	-171298	-25280	-9182	-20805	93800	-132765
1997	0	0	-1252	-1252	-181576	-26796	-9182	-19140	100346	-136329
1998	0	0	-1327	-1327	-192471	-28404	-9182	-17476	107391	-140141
1999	0	0	-1406	-1406	-204019	-30108	-9182	-15812	114909	-144212
2000	0	0	-1491	-1491	-216260	-31915	-9182	-14147	122952	-148552
2001	0	0	-1580	-1580	-229236	-33830	-9182	-12483	131559	-153171
2002	0	0	-1675	-1675	-242990	-35860	-9182	-10818	140768	-158082
2003	0	0	-1775	-1775	-257569	-38011	-9182	-9154	150622	-163294
2004	0	0	-1882	-1882	-273023	-40292	-9182	-7490	161165	-168821
2005	0	0	-1995	-1995	-289405	-42709	-9182	-5825	172447	-174674
2006	0	0	-2114	-2114	-306769	-45272	-9182	-4161	184518	-180865
2007	0	0	-2241	-2241	-325175	-47988	-9182	-2497	197434	-187407
2008	0	0	-2376	-2376	-344686	-50868	-9182	-832	211255	-194312
2009	0	0	-2518	-2518	-365367	-53920	-9182	0	226023	-202425
2010	0	0	-2669	-2669	-387289	-57155	-9182	0	241846	-211759
2011	0	0	-2830	-2830	-410526	-60584	-9182	0	258796	-221496
2012	0	0	-2999	-2999	-435158	-64219	-9182	0	276912	-231646
2013	0	0	-3179	-3179	-461267	-68072	-9182	0	296296	-242225
2014	0	0	-3370	-3370	-488943	-72157	-9182	0	317017	-253245
2015	13257	0	59536	72794	-518280	-76486	-9182	0	336229	-264718
TOTALS	-430841	0	0	-430842	-7562074	-1115985	-290440	-442099	4504174	-4906424

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
150% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-74	34	-40	0	534	493	-6856	-5666	-5184	-4761
1981	-239	110	-129	0	903	773	-8255	-6202	-5458	-4777
1982	-508	234	-274	0	1741	1466	-15940	-10887	-9114	-7687
1983	-1451	851	-1000	0	11585	10584	-105266	-65362	-52326	-42304
1984	-4640	2134	-2506	0	15936	13429	-145933	-82375	-63001	-48873
1985	-7677	3532	-4145	0	13510	9364	-136722	-70160	-51399	-38157
1986	-110564	50859	-59705	39298	0	-20407	-21066	-9827	-6887	-4899
1987	-110320	50747	-59573	35805	0	-23768	-24467	-10376	-6965	-4742
1988	-112045	51540	-60505	34120	0	-26385	-27126	-10458	-6705	-4381
1989	-113959	52421	-61538	32455	0	-29083	-29868	-10469	-6420	-4020
1990	-116050	53382	-62668	30791	0	-31877	-32709	-10422	-6114	-3669
1991	-118325	54429	-63896	29127	0	-34769	-35651	-10327	-5764	-3332
1992	-120793	55564	-65229	27462	0	-37767	-38702	-10191	-5470	-3014
1993	-123462	56792	-66670	25798	0	-40872	-41863	-10022	-5165	-2717
1994	-126341	58116	-68225	24134	0	-44091	-45142	-9824	-4824	-2442
1995	-129438	59541	-69897	22469	0	-47428	-48542	-9604	-4511	-2188
1996	-132765	61071	-71694	20805	0	-50889	-52070	-9365	-4268	-1956
1997	-136329	62711	-73618	19140	0	-54478	-55730	-9112	-3916	-1744
1998	-140141	64464	-75677	17476	0	-58201	-59528	-8848	-3637	-1553
1999	-144212	66337	-77875	15812	0	-62063	-63469	-8577	-3372	-1380
2000	-148552	68333	-80219	14147	0	-66072	-67563	-8300	-3121	-1224
2001	-153171	70458	-82713	12483	0	-70230	-71810	-8020	-2885	-1084
2002	-158082	72717	-85365	10818	0	-74547	-76222	-7738	-2643	-959
2003	-163294	75115	-88179	9154	0	-79025	-80800	-7458	-2455	-847
2004	-168821	77657	-91164	7490	0	-83674	-85566	-7179	-2260	-747
2005	-174674	80350	-94324	5825	0	-88499	-90494	-6903	-2079	-659
2006	-180865	83198	-97667	4161	0	-93506	-95620	-6631	-1910	-580
2007	-187407	86207	-101200	2497	0	-98703	-100944	-6363	-1753	-510
2008	-194312	89383	-104929	832	0	-104097	-106473	-6102	-1608	-449
2009	-202425	93115	-109310	0	0	-109310	-111828	-5826	-1469	-393
2010	-211759	97409	-114350	0	0	-114350	-117019	-5542	-1336	-342
2011	-221496	101887	-119609	0	0	-119609	-122439	-5272	-1216	-298
2012	-231646	106557	-125089	0	0	-125089	-128088	-5014	-1106	-260
2013	-242225	111423	-130802	0	0	-130802	-133981	-4768	-1006	-227
2014	-253245	116492	-136753	0	0	-136753	-140123	-4533	-915	-198
2015	-264718	121770	-142948	0	0	-142948	-70154	-2063	-398	-82
TOTALS	-4906424	2256940	-2649485	442099	44209	-2163177	-2594019	-475769	-288668	-197436

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PROJECT COST ANALYSIS
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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
200% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,060)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	-7350	0	0	-7350	0	0	-74	0	0	-74
1981	-9029	0	0	-9029	0	0	-239	0	0	-239
1982	-17407	0	0	-17407	0	0	-508	0	0	-508
1983	-115851	0	0	-115851	0	0	-1851	0	0	-1851
1984	-159363	0	0	-159363	0	0	-4640	0	0	-4640
1985	-135099	0	-10988	-146087	0	0	-7677	0	0	-7677
1986	0	0	-659	-659	-127536	-14116	-9182	-39298	47683	-142448
1987	0	0	-699	-699	-135188	-14963	-9182	-35805	51021	-144117
1988	0	0	-741	-741	-143299	-15861	-9182	-34120	54542	-147870
1989	0	0	-785	-785	-151897	-16812	-9182	-32455	58414	-151933
1990	0	0	-832	-832	-161011	-17821	-9182	-30791	62583	-156303
1991	0	0	-882	-882	-170672	-18890	-9182	-29127	66878	-160993
1992	0	0	-935	-935	-180912	-20024	-9182	-27462	71559	-166021
1993	0	0	-991	-991	-191767	-21225	-9182	-25798	76568	-171403
1994	0	0	-1051	-1051	-203273	-22499	-9182	-24134	81978	-177159
1995	0	0	-1114	-1114	-215469	-23849	-9182	-22469	87663	-183306
1996	0	0	-1181	-1181	-228398	-25280	-9182	-20805	93880	-189864
1997	0	0	-1252	-1252	-242101	-26796	-9182	-19140	100366	-196854
1998	0	0	-1327	-1327	-256627	-28404	-9182	-17476	107391	-204298
1999	0	0	-1406	-1406	-272025	-30108	-9182	-15812	114909	-212218
2000	0	0	-1491	-1491	-288347	-31915	-9182	-14147	122952	-220638
2001	0	0	-1580	-1580	-305647	-33830	-9182	-12483	131559	-229583
2002	0	0	-1675	-1675	-323986	-35860	-9182	-10818	140768	-239078
2003	0	0	-1775	-1775	-343425	-38011	-9182	-9154	150622	-249151
2004	0	0	-1882	-1882	-364031	-40292	-9182	-7490	161165	-259829
2005	0	0	-1995	-1995	-385873	-42709	-9182	-5825	172447	-271142
2006	0	0	-2114	-2114	-409025	-45272	-9182	-4161	184518	-283122
2007	0	0	-2241	-2241	-433567	-47988	-9182	-2497	197414	-295799
2008	0	0	-2376	-2376	-459581	-50868	-9182	-832	211255	-309207
2009	0	0	-2518	-2518	-487156	-53920	-9182	0	226043	-324214
2010	0	0	-2669	-2669	-516385	-57155	-9182	0	241866	-340856
2011	0	0	-2830	-2830	-547368	-60584	-9182	0	258796	-358338
2012	0	0	-2999	-2999	-580210	-64219	-9182	0	276912	-376699
2013	0	0	-3179	-3179	-615023	-68072	-9182	0	296296	-395981
2014	0	0	-3370	-3370	-651924	-72157	-9182	0	317017	-416226
2015	13257	0	59536	72794	-691040	-76486	-9182	0	339229	-437478
TOTALS	-430841	0	0	-430842	-10082765	-1115985	-290440	-442099	4504174	-7427115

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
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PROJECT: ORANGE COGENERATION
CASE : WESTERN COAL
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	-74	34	-40	0	534	493	-6866	-5666	-5184	-4761
1981	-239	110	-129	0	903	773	-8255	-6202	-5428	-4777
1982	-508	234	-274	0	1741	1466	-15940	-10887	-9114	-7687
1983	-1851	851	-1000	0	11585	10584	-105266	-65362	-52336	-42304
1984	-4640	2134	-2506	0	15936	13429	-145933	-82375	-63091	-48873
1985	-7677	3532	-4145	0	13516	9364	-136722	-70160	-51399	-38157
1986	-142446	65526	-76922	39298	0	-37624	-38283	-17859	-12515	-8903
1987	-184117	66293	-77824	35805	0	-42019	-42718	-18117	-12143	-8279
1988	-147870	66019	-79851	34120	0	-45731	-46472	-17917	-11487	-7505
1989	-151933	69889	-82044	32455	0	-49589	-50374	-17656	-10828	-6780
1990	-156303	71899	-84404	30791	0	-53613	-54445	-17348	-10176	-6106
1991	-160993	74056	-86937	29127	0	-57810	-58692	-17001	-9539	-5486
1992	-166021	76369	-89652	27462	0	-62190	-63125	-16623	-8921	-4917
1993	-171403	78845	-92558	25798	0	-66760	-67751	-16219	-8326	-4397
1994	-177159	81493	-95666	24134	0	-71532	-72583	-15796	-7757	-3926
1995	-183306	84320	-98986	22469	0	-76517	-77631	-15359	-7214	-3499
1996	-189864	87337	-102527	20805	0	-81722	-82903	-14911	-6699	-3114
1997	-196854	90552	-106302	19140	0	-87162	-88414	-14456	-6212	-2767
1998	-204298	93977	-110321	17476	0	-92845	-94172	-13998	-5754	-2456
1999	-212218	97620	-114598	15812	0	-98786	-100192	-13539	-5323	-2178
2000	-220638	101493	-119145	14147	0	-104998	-106489	-13082	-4920	-1929
2001	-229563	105606	-123957	12483	0	-111492	-113072	-12628	-4543	-1707
2002	-239078	109975	-129103	10818	0	-118285	-119960	-12179	-4191	-1509
2003	-249151	114609	-134542	9154	0	-125388	-127163	-11737	-3863	-1333
2004	-259829	119521	-140308	7490	0	-132818	-134700	-11302	-3558	-1177
2005	-271142	124725	-146417	5825	0	-140592	-142587	-10876	-3275	-1038
2006	-283122	130235	-152887	4161	0	-148726	-150840	-10460	-3013	-915
2007	-295799	136067	-159732	2497	0	-157235	-159476	-10053	-2770	-806
2008	-309207	142235	-166972	832	0	-166140	-168516	-9657	-2545	-710
2009	-324214	149138	-175076	0	0	-175076	-177594	-9252	-2332	-623
2010	-340856	156793	-184063	0	0	-184063	-186732	-8844	-2132	-546
2011	-358338	164835	-193503	0	0	-193503	-196333	-8453	-1950	-479
2012	-376699	173281	-203418	0	0	-203418	-206417	-8080	-1782	-419
2013	-395981	182151	-213830	0	0	-213830	-217009	-7722	-1629	-367
2014	-416226	191463	-224763	0	0	-224763	-228133	-7380	-1490	-322
2015	-437478	201239	-236239	0	0	-236239	-163445	-4807	-928	-192
TOTALS	-7427115	3416456	-4010659	442099	442099	-3524351	-3955193	-623947	-354308	-230927

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHANGE CORRELATION
CASE : NO. 6 FUEL OIL
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,000)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS EEFCRF TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-14566	0	0	-14566	0	0	-146	0	0	-146
1982	-25924	0	0	-25924	0	0	-554	0	0	-554
1983	-97113	0	0	-97113	0	0	-1795	0	0	-1795
1984	-126181	0	0	-126181	0	0	-4064	0	0	-4064
1985	-108063	0	-19415	-127478	0	0	-6448	0	0	-6448
1986	0	0	-1165	-1165	-101410	-12042	-7698	-32876	49800	-104226
1987	0	0	-1235	-1235	-108509	-12765	-7698	-29953	53284	-105639
1988	0	0	-1309	-1309	-116104	-13530	-7698	-28544	57016	-108861
1989	0	0	-1387	-1387	-124232	-14342	-7698	-27152	61007	-112416
1990	0	0	-1471	-1471	-132928	-15203	-7698	-25759	65278	-116310
1991	0	0	-1559	-1559	-142233	-16115	-7698	-24367	69847	-120565
1992	0	0	-1652	-1652	-152189	-17082	-7698	-22974	74736	-125207
1993	0	0	-1752	-1752	-162842	-18107	-7698	-21582	79968	-130261
1994	0	0	-1857	-1857	-174241	-19193	-7698	-20190	85566	-135756
1995	0	0	-1968	-1968	-186438	-20345	-7698	-18797	91555	-141723
1996	0	0	-2086	-2086	-199489	-21565	-7698	-17405	97964	-148193
1997	0	0	-2211	-2211	-213453	-22859	-7698	-16012	104822	-155201
1998	0	0	-2344	-2344	-228395	-24231	-7698	-14620	112159	-162785
1999	0	0	-2485	-2485	-244382	-25685	-7698	-13228	120010	-170982
2000	0	0	-2634	-2634	-261489	-27226	-7698	-11835	128411	-179837
2001	0	0	-2792	-2792	-279793	-28859	-7698	-10443	137400	-189394
2002	0	0	-2959	-2959	-299379	-30591	-7698	-9051	147018	-199701
2003	0	0	-3137	-3137	-320335	-32426	-7698	-7658	157369	-210809
2004	0	0	-3325	-3325	-342759	-34372	-7698	-6266	168321	-222774
2005	0	0	-3525	-3525	-366752	-36434	-7698	-4873	180103	-235655
2006	0	0	-3736	-3736	-392425	-38620	-7698	-3481	192710	-249514
2007	0	0	-3960	-3960	-419895	-40938	-7698	-2089	206200	-264419
2008	0	0	-4196	-4196	-449287	-43394	-7698	-696	220614	-280441
2009	0	0	-4450	-4450	-480737	-45997	-7698	0	236078	-298354
2010	0	0	-4717	-4717	-514389	-48757	-7698	0	252604	-318240
2011	0	0	-5000	-5000	-550396	-51683	-7698	0	270286	-339490
2012	0	0	-5300	-5300	-588924	-54784	-7698	0	289206	-362199
2013	0	0	-5618	-5618	-630148	-58071	-7698	0	309451	-386466
2014	0	0	-5955	-5955	-674259	-61555	-7698	0	331112	-412399
2015	12450	0	105197	117648	-721457	-65248	-7698	0	350200	-440113
TOTALS	-359400	0	0	-359405	-9579270	-952019	-243983	-369851	4704108	-6440975

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : NO. 5 FUEL OIL
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-146	67	-79	0	1256	1176	-13389	-10059	-8803	-7748
1982	-554	255	-299	0	2593	2293	-23634	-16142	-13513	-11395
1983	-1795	826	-969	0	9711	8741	-88371	-54871	-43936	-35514
1984	-4064	1869	-2195	0	12618	10422	-115758	-65342	-50045	-38767
1985	-6488	2984	-3504	0	10806	7301	-120176	-61669	-45179	-33539
1986	-104226	47943	-56283	32876	0	-23407	-24572	-11463	-2033	-5715
1987	-105639	48593	-57046	29953	0	-27093	-28328	-12014	-2053	-5490
1988	-108861	50075	-58786	28544	0	-30242	-31551	-12164	-2769	-5096
1989	-112416	51711	-60705	27152	0	-33553	-34940	-12246	-7510	-4703
1990	-116310	53502	-62808	25759	0	-37049	-38520	-12274	-7200	-4320
1991	-120565	55460	-65105	24367	0	-40738	-42297	-12252	-6874	-3953
1992	-125207	57595	-67612	22974	0	-44638	-46290	-12190	-6542	-3605
1993	-130261	59920	-70341	21582	0	-48759	-50511	-12092	-6208	-3278
1994	-135756	62447	-73309	20190	0	-53119	-54976	-11964	-5875	-2974
1995	-141723	65192	-76531	18797	0	-57734	-59702	-11812	-5548	-2691
1996	-148193	68168	-80025	17405	0	-62620	-64706	-11638	-5229	-2430
1997	-155201	71392	-83809	16012	0	-67797	-70008	-11447	-4919	-2191
1998	-162785	74880	-87905	14620	0	-73285	-75629	-11242	-4621	-1973
1999	-170982	78651	-92331	13228	0	-79103	-81588	-11025	-4335	-1773
2000	-179837	82725	-97112	11835	0	-85277	-87911	-10800	-4062	-1592
2001	-189394	87121	-102273	10443	0	-91830	-94622	-10567	-3801	-1428
2002	-199701	91862	-107839	9051	0	-98788	-101747	-10330	-3554	-1280
2003	-210809	96972	-113837	7658	0	-106179	-109316	-10089	-3321	-1146
2004	-222774	102476	-120298	6266	0	-114032	-117357	-9847	-3100	-1025
2005	-235655	108401	-127254	4873	0	-122381	-125906	-9604	-2892	-917
2006	-249514	114776	-134738	3481	0	-131257	-134993	-9361	-2696	-819
2007	-264419	121632	-142787	2089	0	-140698	-144658	-9119	-2512	-731
2008	-280441	129002	-151439	696	0	-150743	-154941	-8879	-2340	-653
2009	-298354	137242	-161112	0	0	-161112	-165562	-8626	-2174	-581
2010	-318240	146390	-171850	0	0	-171850	-176567	-8363	-2016	-517
2011	-339490	156165	-183325	0	0	-183325	-188325	-8109	-1870	-459
2012	-362199	166611	-195588	0	0	-195588	-200888	-7863	-1735	-408
2013	-386466	177774	-208692	0	0	-208692	-214310	-7626	-1609	-363
2014	-412399	189703	-222696	0	0	-222696	-228651	-7397	-1493	-323
2015	-440113	202452	-237661	0	0	-237661	-244013	-7329	-1481	-281
TOTALS	-6440975	2962834	-3478143	369851	36984	-3071308	-3430713	-513997	-290062	-189525

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : NO. 6 FUEL OIL
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.070)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-14566	0	0	-14566	0	0	-146	0	0	-146
1982	-25928	0	0	-25928	0	0	-554	0	0	-554
1983	-97113	0	0	-97113	0	0	-1795	0	0	-1795
1984	-126181	0	0	-126181	0	0	-4064	0	0	-4064
1985	-108063	0	-19415	-127478	0	0	-6488	0	0	-6488
1986	0	0	-1165	-1165	-112678	-12042	-7698	-32876	49800	-115494
1987	0	0	-1235	-1235	-120565	-12765	-7698	-29953	53286	-117695
1988	0	0	-1309	-1309	-129005	-13530	-7698	-28544	57016	-121761
1989	0	0	-1387	-1387	-138035	-14342	-7698	-27152	61007	-126220
1990	0	0	-1471	-1471	-147698	-15203	-7698	-25759	65278	-131080
1991	0	0	-1559	-1559	-158037	-16115	-7698	-24367	69807	-136369
1992	0	0	-1652	-1652	-169099	-17082	-7698	-22974	74736	-142117
1993	0	0	-1752	-1752	-180936	-18107	-7698	-21582	79968	-148355
1994	0	0	-1857	-1857	-193602	-19193	-7698	-20190	85566	-155117
1995	0	0	-1968	-1968	-207154	-20345	-7698	-18797	91555	-162439
1996	0	0	-2086	-2086	-221655	-21565	-7698	-17405	97964	-170359
1997	0	0	-2211	-2211	-237171	-22859	-7698	-16012	104822	-178919
1998	0	0	-2344	-2344	-253772	-24231	-7698	-14620	112159	-188162
1999	0	0	-2485	-2485	-271537	-25685	-7698	-13228	120010	-198137
2000	0	0	-2634	-2634	-290544	-27226	-7698	-11835	128411	-208892
2001	0	0	-2792	-2792	-310882	-28859	-7698	-10443	137400	-220483
2002	0	0	-2959	-2959	-332644	-30591	-7698	-9051	147018	-232966
2003	0	0	-3137	-3137	-355929	-32426	-7698	-7658	157309	-246402
2004	0	0	-3325	-3325	-380844	-34372	-7698	-6266	168321	-260859
2005	0	0	-3525	-3525	-407503	-36434	-7698	-4873	180103	-276406
2006	0	0	-3736	-3736	-436028	-38620	-7698	-3481	192710	-293117
2007	0	0	-3960	-3960	-466550	-40938	-7698	-2089	206200	-311074
2008	0	0	-4198	-4198	-499209	-43394	-7698	-696	220634	-330363
2009	0	0	-4450	-4450	-534154	-45997	-7698	0	236078	-351770
2010	0	0	-4717	-4717	-571544	-48757	-7698	0	252604	-375396
2011	0	0	-5000	-5000	-611552	-51683	-7698	0	270206	-400647
2012	0	0	-5300	-5300	-654361	-54784	-7698	0	289206	-427636
2013	0	0	-5618	-5618	-700166	-58071	-7698	0	309451	-456484
2014	0	0	-5955	-5955	-749178	-61555	-7698	0	331112	-487319
2015	12450	0	105197	117648	-801620	-65248	-7698	0	354290	-526276
TOTALS	-359400	0	0	-359405	-10643654	-952019	-243983	-369851	4704148	-7505359

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : NO. 6 FUEL OIL
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-146	67	-79	0	1256	1176	-13389	-10059	-8803	-7748
1982	-554	255	-299	0	2503	2293	-23634	-16142	-13513	-11398
1983	-1795	826	-969	0	9711	8741	-88371	-54871	-43936	-35514
1984	-4064	1869	-2195	0	12618	10422	-115758	-65342	-50045	-38767
1985	-6488	2984	-3504	0	10806	7301	-120176	-61669	-45179	-33539
1986	-115494	53127	-62367	32876	0	-29491	-30656	-14301	-10022	-7130
1987	-117695	54139	-63556	29953	0	-33603	-34838	-14775	-9903	-6752
1988	-121761	56010	-65751	28544	0	-37207	-38516	-14850	-9521	-6221
1989	-126220	58061	-68159	27152	0	-41007	-42394	-14859	-9112	-5706
1990	-131080	60296	-70784	25759	0	-45025	-46496	-14815	-8690	-5215
1991	-136369	62729	-73640	24367	0	-49273	-50832	-14724	-8262	-4751
1992	-142117	65373	-76744	22974	0	-53770	-55422	-14594	-7833	-4317
1993	-144355	68243	-80112	21582	0	-58530	-60282	-14431	-7408	-3913
1994	-155117	71353	-83764	20190	0	-63574	-65431	-14240	-6992	-3539
1995	-162439	74721	-87718	18797	0	-68921	-70889	-14025	-6587	-3195
1996	-170359	78365	-91994	17405	0	-74589	-76675	-13791	-6196	-2880
1997	-178919	82302	-96617	16012	0	-80605	-82816	-13541	-5819	-2592
1998	-188162	86554	-101608	14620	0	-86988	-89332	-13279	-5488	-2330
1999	-198137	91142	-106995	13226	0	-93767	-96252	-13007	-5114	-2092
2000	-208892	96090	-112802	11835	0	-100967	-103601	-12727	-4786	-1877
2001	-220483	101422	-119061	10443	0	-108618	-111410	-12442	-4476	-1682
2002	-232966	107164	-125802	9051	0	-116751	-119710	-12154	-4182	-1506
2003	-246402	113345	-133057	7658	0	-125399	-128536	-11863	-3905	-1347
2004	-260850	119995	-140854	6266	0	-134598	-137923	-11572	-3643	-1205
2005	-276406	127146	-149260	4873	0	-143387	-147912	-11282	-3368	-1077
2006	-293117	134833	-158284	3481	0	-154803	-158539	-10994	-3167	-962
2007	-311074	143094	-167980	2089	0	-165891	-169851	-10707	-2900	-859
2008	-330363	151966	-178397	696	0	-177701	-181899	-10424	-2747	-766
2009	-351770	161814	-189956	0	0	-189956	-194406	-10128	-2553	-682
2010	-375396	172681	-202715	0	0	-202715	-207432	-9824	-2369	-607
2011	-400647	184297	-216350	0	0	-216350	-221350	-9531	-2198	-540
2012	-427636	196712	-230924	0	0	-230924	-236224	-9246	-2040	-480
2013	-456484	209982	-246502	0	0	-246502	-252120	-8971	-1893	-427
2014	-487319	224166	-263153	0	0	-263153	-269108	-8705	-1757	-390
2015	-520276	239327	-280949	0	0	-280949	-163301	-4802	-927	-192
TOTALS	-7505359	3452450	-4052911	369851	36984	-3646076	-4005481	-572676	-315349	-202164

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHARGE COGENERATION
CASE : NO. 6 FUEL OIL
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-14566	0	0	-14566	0	0	-146	0	0	-146
1982	-25928	0	0	-25928	0	0	-554	0	0	-554
1983	-97113	0	0	-97113	0	0	-1795	0	0	-1795
1984	-126181	0	0	-126181	0	0	-4064	0	0	-4064
1985	-108063	0	-19415	-127478	0	0	-6488	0	0	-6488
1986	0	0	-1165	-1165	-169017	-12042	-7698	-32876	49800	-171833
1987	0	0	-1235	-1235	-180848	-12765	-7698	-29953	53286	-177978
1988	0	0	-1309	-1309	-193508	-13530	-7698	-28544	57016	-186264
1989	0	0	-1387	-1387	-207053	-14342	-7698	-27152	61007	-195238
1990	0	0	-1471	-1471	-221547	-15203	-7698	-25759	65278	-204929
1991	0	0	-1559	-1559	-237055	-16115	-7698	-24367	69847	-215388
1992	0	0	-1652	-1652	-253649	-17082	-7698	-22974	74736	-226667
1993	0	0	-1752	-1752	-271404	-18107	-7698	-21582	79968	-238823
1994	0	0	-1857	-1857	-290403	-19193	-7698	-20190	85546	-251918
1995	0	0	-1968	-1968	-310731	-20345	-7698	-18797	91555	-266018
1996	0	0	-2086	-2086	-332482	-21565	-7698	-17405	97964	-281186
1997	0	0	-2211	-2211	-355756	-22859	-7698	-16012	104822	-297504
1998	0	0	-2344	-2344	-380659	-24231	-7698	-14620	112159	-315048
1999	0	0	-2485	-2485	-407305	-25685	-7698	-13228	120010	-333905
2000	0	0	-2634	-2634	-435816	-27226	-7698	-11835	128411	-354164
2001	0	0	-2792	-2792	-466323	-28859	-7698	-10443	137400	-375924
2002	0	0	-2959	-2959	-498966	-30591	-7698	-9051	147018	-399288
2003	0	0	-3137	-3137	-533894	-32426	-7698	-7658	157369	-424367
2004	0	0	-3325	-3325	-571266	-34372	-7698	-6266	168321	-451281
2005	0	0	-3525	-3525	-611255	-36434	-7698	-4873	180103	-480157
2006	0	0	-3736	-3736	-654043	-38620	-7698	-3481	192710	-511131
2007	0	0	-3960	-3960	-699826	-40938	-7698	-2089	206200	-540350
2008	0	0	-4198	-4198	-748813	-43394	-7698	-696	220634	-579967
2009	0	0	-4450	-4450	-801230	-45997	-7698	0	236078	-618847
2010	0	0	-4717	-4717	-857316	-48757	-7698	0	252604	-661168
2011	0	0	-5000	-5000	-917329	-51683	-7698	0	270286	-706423
2012	0	0	-5300	-5300	-981542	-54784	-7698	0	289206	-754817
2013	0	0	-5618	-5618	-1050249	-58071	-7698	0	309491	-806567
2014	0	0	-5955	-5955	-1123767	-61555	-7698	0	331112	-861908
2015	12450	0	105197	117648	-1202431	-65248	-7698	0	354290	-921087
TOTALS	-359400	0	0	-359405	-15965481	-952019	-243983	-369851	4704148	-12827187

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHARGE COGENERATION
CASE : NO. 6 FUEL OIL
150% FUEL COST

YEAR	(11) TOTAL EXPS. BEFORE TAX (10 FWD)	(12) TAXES (-.40*11)	(13) TOTAL EXPS. AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-ACF (CR=.10)	(19) PRESENT WORTH-ACF (CR=.15)	(20) PRESENT WORTH-ACF (CR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-146	67	-79	0	1256	1176	-13389	-10059	-2803	-7748
1982	-554	255	-299	0	2593	2293	-23634	-16142	-13513	-11398
1983	-1795	826	-969	0	9711	8741	-88371	-54871	-43936	-35514
1984	-4064	1849	-2195	0	12618	10422	-115758	-65342	-50045	-38767
1985	-6488	2984	-3504	0	10806	7301	-120176	-61669	-45179	-33539
1986	-171833	79042	-92791	32876	0	-59915	-61080	-28494	-19967	-14205
1987	-177978	81869	-96109	29953	0	-66156	-67391	-28580	-19157	-13061
1988	-185264	85681	-100583	28544	0	-72039	-73348	-29279	-18131	-11846
1989	-195238	89809	-105429	27152	0	-78277	-79864	-29922	-17123	-10722
1990	-204929	94267	-110662	25759	0	-84903	-86374	-27521	-16144	-9687
1991	-215388	99078	-116310	24367	0	-91943	-93502	-27084	-15197	-8739
1992	-226667	104266	-122401	22974	0	-99427	-101079	-26617	-14285	-7873
1993	-238823	109858	-128965	21582	0	-107383	-109135	-26126	-13412	-7083
1994	-251918	115882	-136036	20190	0	-115846	-117703	-25616	-12578	-6366
1995	-266016	122367	-143649	18797	0	-124852	-126820	-25091	-11785	-5716
1996	-281146	129345	-151841	17405	0	-134436	-136522	-24555	-11032	-5128
1997	-297504	136851	-160653	16012	0	-144641	-146852	-24011	-10319	-4597
1998	-315048	144922	-170126	14620	0	-155506	-157850	-23463	-9645	-4117
1999	-333905	153596	-180309	13228	0	-167081	-169566	-22914	-9009	-3686
2000	-354164	162915	-191249	11835	0	-179414	-182048	-22364	-8411	-3298
2001	-375924	172924	-203000	10443	0	-192557	-195349	-21816	-7808	-2949
2002	-399288	183672	-215616	9051	0	-206565	-209524	-21272	-7320	-2636
2003	-424367	195208	-229159	7658	0	-221501	-224638	-20733	-6824	-2355
2004	-451281	207589	-243692	6266	0	-237426	-240751	-20200	-6340	-2103
2005	-480157	220872	-259285	4873	0	-254412	-257937	-19675	-5925	-1878
2006	-511131	235120	-276011	3481	0	-272530	-276266	-19157	-5518	-1676
2007	-544350	250400	-293950	2089	0	-291861	-295821	-18648	-5138	-1495
2008	-579967	266784	-313183	696	0	-312487	-316885	-18149	-4783	-1334
2009	-618847	284669	-334178	0	0	-334178	-338628	-17642	-4407	-1189
2010	-661168	304137	-357031	0	0	-357031	-361748	-17133	-4131	-1058
2011	-708423	324954	-381469	0	0	-381469	-386469	-16640	-3838	-942
2012	-754817	347215	-407602	0	0	-407602	-412902	-16162	-3565	-839
2013	-806567	371021	-435446	0	0	-435446	-441164	-15698	-3313	-747
2014	-861908	396477	-465431	0	0	-465431	-471386	-15249	-3078	-665
2015	-921087	423696	-497388	0	0	-497388	-503740	-14868	-2866	-546
TOTALS	-12827187	5900490	-6926700	369851	36984	-6519865	-6879270	-866051	-441865	-265385

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : NO. 6 FUEL OIL
200% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.000)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.070)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-14566	0	0	-14566	0	0	-146	0	0	-146
1982	-25928	0	0	-25928	0	0	-554	0	0	-554
1983	-97113	0	0	-97113	0	0	-1795	0	0	-1795
1984	-126181	0	0	-126181	0	0	-4064	0	0	-4064
1985	-108063	0	-19415	-127478	0	0	-6488	0	0	-6488
1986	0	0	-1165	-1165	-225356	-12042	-7698	-32876	49800	-228172
1987	0	0	-1235	-1235	-241131	-12765	-7698	-29953	53286	-238261
1988	0	0	-1309	-1309	-258010	-13530	-7698	-28544	57016	-250766
1989	0	0	-1387	-1387	-276071	-14342	-7698	-27152	61007	-264255
1990	0	0	-1471	-1471	-295396	-15203	-7698	-25759	65278	-278778
1991	0	0	-1559	-1559	-316073	-16115	-7698	-24367	69807	-294406
1992	0	0	-1652	-1652	-336199	-17082	-7698	-22974	74716	-311216
1993	0	0	-1752	-1752	-361873	-18107	-7698	-21582	79968	-329291
1994	0	0	-1857	-1857	-387204	-19193	-7698	-20190	85566	-348719
1995	0	0	-1968	-1968	-414308	-20345	-7698	-18797	91555	-369592
1996	0	0	-2086	-2086	-443309	-21565	-7698	-17405	97964	-392013
1997	0	0	-2211	-2211	-474341	-22859	-7698	-16012	104822	-416089
1998	0	0	-2344	-2344	-507545	-24231	-7698	-14620	112159	-441935
1999	0	0	-2485	-2485	-543073	-25685	-7698	-13228	120010	-469673
2000	0	0	-2634	-2634	-581088	-27226	-7698	-11835	128411	-499436
2001	0	0	-2792	-2792	-621764	-28859	-7698	-10443	137400	-531365
2002	0	0	-2959	-2959	-665288	-30591	-7698	-9051	147018	-565609
2003	0	0	-3137	-3137	-711858	-32426	-7698	-7658	157309	-602331
2004	0	0	-3325	-3325	-761688	-34372	-7698	-6266	168321	-641703
2005	0	0	-3525	-3525	-815006	-36434	-7698	-4873	180103	-683909
2006	0	0	-3736	-3736	-872057	-38620	-7698	-3481	192710	-729146
2007	0	0	-3960	-3960	-933101	-40938	-7698	-2089	206200	-777625
2008	0	0	-4198	-4198	-998418	-43394	-7698	-696	220634	-825572
2009	0	0	-4450	-4450	-1068307	-45997	-7698	0	236078	-885524
2010	0	0	-4717	-4717	-1143089	-48757	-7698	0	252604	-946940
2011	0	0	-5000	-5000	-1223105	-51683	-7698	0	270286	-1012199
2012	0	0	-5300	-5300	-1308722	-54784	-7698	0	289206	-1081597
2013	0	0	-5618	-5618	-1400333	-58071	-7698	0	309451	-1156651
2014	0	0	-5955	-5955	-1498356	-61555	-7698	0	331112	-1236497
2015	12450	0	105197	117648	-1603241	-65248	-7698	0	354240	-1321897
TOTALS	-359400	0	0	-359405	-21287308	-952019	-243983	-369851	4704108	-18149014

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : NO. 6 FUEL OIL
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.40*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	-146	57	-79	0	1256	1176	-13389	-10059	-2803	-7708
1982	-554	255	-299	0	2593	2293	-23634	-16142	-13513	-11398
1983	-1795	826	-969	0	9711	8741	-88371	-54871	-43936	-35514
1984	-4064	1869	-2195	0	12618	10422	-115758	-65342	-50005	-38767
1985	-6488	2984	-3504	0	10806	7301	-120176	-61669	-45179	-33539
1986	-228172	104958	-123214	32876	0	-90338	-91503	-42687	-29912	-21281
1987	-238261	109599	-128662	29953	0	-99709	-99944	-42386	-28410	-19370
1988	-250766	115352	-135414	28544	0	-106870	-108179	-41708	-26740	-17472
1989	-264255	121557	-142698	27152	0	-115546	-116933	-40984	-25134	-15738
1990	-278778	128237	-150541	25759	0	-124782	-126253	-40228	-23568	-14160
1991	-294406	135426	-158980	24367	0	-134613	-136172	-39444	-22132	-12727
1992	-311216	143159	-168057	22974	0	-145083	-146735	-38640	-20718	-11429
1993	-329291	151473	-177818	21582	0	-156236	-157988	-37821	-19416	-10254
1994	-348719	160410	-188309	20190	0	-168119	-169976	-36992	-18144	-9194
1995	-369592	170012	-199580	18797	0	-180783	-182751	-36156	-16982	-8237
1996	-392013	180326	-211687	17405	0	-194282	-196368	-35319	-15868	-7376
1997	-416089	191401	-224688	16012	0	-208676	-210887	-34482	-14818	-6601
1998	-441935	203289	-238646	14620	0	-224026	-226370	-33648	-13831	-5905
1999	-469673	216049	-253624	13228	0	-240396	-242881	-32821	-12904	-5279
2000	-499436	229740	-269696	11835	0	-257861	-260495	-32001	-12035	-4719
2001	-531365	244427	-286938	10443	0	-276495	-279287	-31190	-11220	-4216
2002	-565609	260180	-305429	9051	0	-296378	-299337	-30390	-10457	-3765
2003	-602331	277072	-325259	7658	0	-317601	-320738	-29603	-9743	-3362
2004	-641703	295183	-346520	6266	0	-340254	-343579	-28828	-9076	-3001
2005	-683909	314598	-369311	4873	0	-364438	-367963	-28067	-8452	-2675
2006	-729146	335406	-393740	3481	0	-390259	-393995	-27321	-7870	-2390
2007	-777625	357707	-419918	2089	0	-417829	-421789	-26589	-7326	-2132
2008	-829572	381602	-447970	696	0	-447274	-451472	-25873	-6819	-1902
2009	-885924	407525	-478399	0	0	-478399	-482849	-25156	-6301	-1695
2010	-946940	435592	-511348	0	0	-511348	-516065	-24442	-5894	-1510
2011	-1012199	465611	-546588	0	0	-546588	-551588	-23750	-5478	-1345
2012	-1081997	497718	-584279	0	0	-584279	-589579	-23078	-5091	-1198
2013	-1154651	532059	-622492	0	0	-622492	-630210	-22425	-4732	-1067
2014	-1236497	568788	-667709	0	0	-667709	-673664	-21792	-4399	-950
2015	-1321897	608072	-713825	0	0	-713825	-596177	-17533	-3385	-701
TOTALS	-18149014	8348529	-9800485	369851	36984	-9393650	-9753055	-1159423	-568425	-328601

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : HTGP
60% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-13104	0	0	-13104	0	0	-131	0	0	-131
1980	-46941	0	0	-46941	0	0	-734	0	0	-734
1981	-77851	0	0	-77851	0	0	-1997	0	0	-1997
1982	-124982	0	0	-124982	0	0	-4105	0	0	-4105
1983	-155262	0	0	-155262	0	0	-7030	0	0	-7030
1984	-110754	0	0	-110754	0	0	-9830	0	0	-9830
1985	-24568	0	0	-24568	0	0	-11380	0	0	-11380
1986	0	0	0	0	-23250	-7319	-11853	-49375	52817	-38940
1987	0	0	0	0	-24389	-7758	-11853	-44986	56514	-32473
1988	0	0	0	0	-25584	-8224	-11853	-42869	60470	-28060
1989	0	0	0	0	-26838	-8717	-11853	-40778	64703	-23483
1990	0	0	0	0	-28153	-9240	-11853	-38687	69232	-18701
1991	0	0	0	0	-29533	-9794	-11853	-36596	74079	-13698
1992	0	0	0	0	-30980	-10382	-11853	-34504	79264	-8456
1993	0	0	0	0	-32498	-11005	-11853	-32413	84813	-2957
1994	0	0	0	0	-34090	-11665	-11853	-30322	90749	2817
1995	0	0	0	0	-35760	-12365	-11853	-28231	97102	8891
1996	0	0	0	0	-37513	-13107	-11853	-26140	103899	15285
1997	0	0	0	0	-39351	-13894	-11853	-24049	111172	22025
1998	0	0	0	0	-41279	-14727	-11853	-21957	118954	29136
1999	0	0	0	0	-43302	-15611	-11853	-19866	127281	36648
2000	0	0	0	0	-45423	-16548	-11853	-17775	136190	44590
2001	0	0	0	0	-47649	-17540	-11853	-15684	145724	52996
2002	0	0	0	0	-49984	-18593	-11853	-13593	155924	61901
2003	0	0	0	0	-52433	-19708	-11853	-11501	166839	71342
2004	0	0	0	0	-55002	-20891	-11853	-9410	178518	81360
2005	0	0	0	0	-57698	-22144	-11853	-7319	191014	91999
2006	0	0	0	0	-60525	-23473	-11853	-5228	204385	103305
2007	0	0	0	0	-63490	-24881	-11853	-3137	218692	115329
2008	0	0	0	0	-66601	-26374	-11853	-1046	234001	128125
2009	0	0	0	0	-69865	-27957	-11853	0	250381	140704
2010	0	0	0	0	-73288	-29634	-11853	0	267907	153130
2011	0	0	0	0	-76879	-31412	-11853	0	286661	166515
2012	0	0	0	0	-80647	-33297	-11853	0	306727	180929
2013	0	0	0	0	-84598	-35295	-11853	0	328198	196450
2014	0	0	0	0	-88744	-37412	-11853	0	351172	213161
2015	14121	0	0	14121	-93092	-39657	-11853	0	375754	231150
TOTALS	-543344	0	0	-543345	-1518438	-578627	-390811	-555466	4989136	1945793

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CRANGE COGENERATION
CASE : HTGR
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DF=.10)	(19) PRESENT WORTH=NCF (DF=.15)	(20) PRESENT WORTH=NCF (DF=.20)
1979	-131	60	-71	0	1110	1038	-12069	-10972	-10495	-10058
1980	-734	338	-396	0	4694	4297	-42643	-35242	-32244	-29613
1981	-1997	919	-1078	0	7785	6706	-71144	-53452	-46778	-41171
1982	-4105	1888	-2217	0	12898	10680	-118301	-80801	-67619	-57051
1983	-7030	3234	-3796	0	15526	11729	-143532	-89122	-71341	-57682
1984	-9830	4522	-5308	0	11075	5766	-104987	-59262	-45389	-35160
1985	-11380	5235	-6145	0	-2457	-3688	-28256	-14500	-10622	-7886
1986	-38980	17930	-21050	49375	0	28324	28324	13212	9288	6586
1987	-32473	14937	-17536	44986	0	27449	27449	11640	7802	5319
1988	-28060	12907	-15153	42869	0	27715	27715	10684	6850	4475
1989	-23483	10802	-12681	40778	0	28096	28096	9846	6038	3780
1990	-18701	8602	-10099	38687	0	28587	28587	9108	5342	3205
1991	-13628	6300	-7328	36596	0	29197	29197	8456	4744	2728
1992	-8456	3889	-4567	34504	0	29936	29936	7882	4210	2331
1993	-2957	1360	-1597	32413	0	30815	30815	7376	3786	1999
1994	2817	-1296	1521	30322	0	31842	31842	6929	3402	1721
1995	8891	-4090	4801	28231	0	33031	33031	6534	3048	1488
1996	15285	-7031	8254	26140	0	34393	34393	6185	2778	1291
1997	22025	-10131	11894	24049	0	35942	35942	5876	2524	1124
1998	29136	-13402	15734	21957	0	37690	37690	5601	2302	982
1999	36648	-16858	19790	19866	0	39655	39655	5358	2106	861
2000	44590	-20511	24079	17775	0	41853	41853	5140	1913	757
2001	52096	-24378	28618	15664	0	44301	44301	4946	1779	668
2002	61901	-28474	33427	13593	0	47019	47019	4773	1642	590
2003	71342	-32817	38525	11501	0	50025	50025	4616	1519	523
2004	81360	-37425	43935	9410	0	53344	53344	4475	1408	485
2005	91999	-42319	49680	7319	0	56998	56998	4347	1308	414
2006	103305	-47520	55785	5228	0	61012	61012	4230	1218	369
2007	115329	-53051	62278	3137	0	65414	65414	4123	1115	330
2008	128125	-58937	69188	1046	0	70233	70233	4024	1040	295
2009	140704	-64724	75980	0	0	75979	75979	3957	997	266
2010	153130	-70440	82690	0	0	82689	82689	3915	903	241
2011	166515	-76597	89918	0	0	89917	89917	3871	802	218
2012	180929	-83227	97702	0	0	97701	97701	3823	703	197
2013	196450	-90367	106083	0	0	106082	106082	3774	706	179
2014	213161	-98054	115107	0	0	115106	115106	3723	751	161
2015	231150	-106329	124821	0	0	124820	124820	4085	788	162
TOTALS	1945793	-895055	1050738	555466	55545	1661728	1118354	-160794	-201201	-194847

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASE : RTGR
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,000)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER -MAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-13108	0	0	-13108	0	0	-131	0	0	-131
1980	-46941	0	0	-46941	0	0	-734	0	0	-734
1981	-77851	0	0	-77851	0	0	-1997	0	0	-1997
1982	-128982	0	0	-128982	0	0	-4105	0	0	-4105
1983	-155262	0	0	-155262	0	0	-7030	0	0	-7030
1984	-110754	0	0	-110754	0	0	-9830	0	0	-9830
1985	-24568	0	0	-24568	0	0	-11380	0	0	-11380
1986	0	0	0	0	-25833	-7319	-11853	-49375	52817	-41563
1987	0	0	0	0	-27099	-7758	-11853	-44986	56514	-35182
1988	0	0	0	0	-28427	-8224	-11853	-42869	60470	-30903
1989	0	0	0	0	-29820	-8717	-11853	-40778	64703	-26465
1990	0	0	0	0	-31281	-9240	-11853	-38687	69242	-21829
1991	0	0	0	0	-32813	-9794	-11853	-36596	74079	-16979
1992	0	0	0	0	-34421	-10382	-11853	-34504	79264	-11897
1993	0	0	0	0	-36108	-11005	-11853	-32413	84813	-6567
1994	0	0	0	0	-37877	-11665	-11853	-30322	90709	-969
1995	0	0	0	0	-39733	-12365	-11853	-28231	97102	4918
1996	0	0	0	0	-41680	-13107	-11853	-26140	103849	11117
1997	0	0	0	0	-43723	-13894	-11853	-24049	111172	17053
1998	0	0	0	0	-45865	-14727	-11853	-21957	118964	24550
1999	0	0	0	0	-48112	-15611	-11853	-19866	127281	31837
2000	0	0	0	0	-50470	-16548	-11853	-17775	136190	39544
2001	0	0	0	0	-52943	-17540	-11853	-15684	145754	47742
2002	0	0	0	0	-55537	-18593	-11853	-13593	155924	56347
2003	0	0	0	0	-58258	-19708	-11853	-11501	166839	65516
2004	0	0	0	0	-61113	-20891	-11853	-9410	178518	75249
2005	0	0	0	0	-64108	-22144	-11853	-7319	191014	85549
2006	0	0	0	0	-67249	-23473	-11853	-5228	204385	96581
2007	0	0	0	0	-70544	-24881	-11853	-3137	218692	108275
2008	0	0	0	0	-74001	-26374	-11853	-1046	234061	120726
2009	0	0	0	0	-77627	-27957	-11853	0	250381	132943
2010	0	0	0	0	-81430	-29634	-11853	0	267967	144988
2011	0	0	0	0	-85420	-31412	-11853	0	286661	157974
2012	0	0	0	0	-89606	-33297	-11853	0	306727	171970
2013	0	0	0	0	-93997	-35295	-11853	0	328198	187052
2014	0	0	0	0	-98603	-37412	-11853	0	351172	203302
2015	14121	0	0	14121	-103434	-39657	-11853	0	375764	220808
TOTALS	-543344	0	0	-543345	-1687131	-578627	-390811	-555466	498916	1777100

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 2 OF 2

PROJECT: ORANGE COGENERATION
CASE : HIGR
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DF=.10)	(19) PRESENT WORTH=NCF (DF=.15)	(20) PRESENT WORTH=NCF (DF=.20)
1979	-131	60	-71	0	1110	1038	-12069	-10972	-10495	-10058
1980	-734	338	-396	0	4694	4297	-42643	-35242	-32204	-29613
1981	-1997	919	-1078	0	7785	6706	-71144	-53452	-46778	-41171
1982	-4105	1888	-2217	0	12898	10680	-118301	-80801	-67639	-57051
1983	-7030	3234	-3796	0	15526	11729	-143532	-89122	-71361	-57682
1984	-9830	4522	-5308	0	11075	5766	-104987	-59262	-45389	-35160
1985	-11380	5235	-6145	0	2457	-3688	-28256	-14500	-10622	-7886
1986	-41583	19119	-22464	49375	0	26930	26930	12562	8802	6262
1987	-35182	16183	-18999	46986	0	25986	25986	11020	7386	5035
1988	-30903	14215	-16688	42869	0	26180	26180	10093	6470	4227
1989	-26485	12173	-14292	40778	0	26485	26485	9282	5692	3564
1990	-21829	10041	-11788	38687	0	26898	26898	8570	5026	3016
1991	-16979	7810	-9169	36596	0	27426	27426	7943	4456	2562
1992	-11897	5472	-6425	34504	0	28078	28078	7393	3967	2186
1993	-6567	3020	-3547	32413	0	28865	28865	6909	3506	1872
1994	-969	445	-524	30322	0	29797	29797	6484	3183	1611
1995	4918	-2262	2656	28231	0	30886	30886	6110	2869	1391
1996	11117	-5114	6003	26140	0	32142	32142	5780	2596	1206
1997	17653	-8120	9533	24049	0	33581	33581	5490	2369	1050
1998	24550	-11293	13257	21957	0	35213	35213	5233	2151	917
1999	31837	-14645	17192	19866	0	37057	37057	5007	1968	804
2000	39544	-18190	21354	17775	0	39128	39128	4806	1807	706
2001	47702	-21943	25759	15684	0	41442	41442	4627	1664	625
2002	56347	-25920	30427	13593	0	44019	44019	4468	1537	553
2003	65516	-30138	35378	11501	0	46878	46878	4326	1423	490
2004	75249	-34615	40634	9410	0	50043	50043	4198	1321	436
2005	85589	-39371	46218	7319	0	53536	53536	4083	1229	389
2006	96581	-44427	52154	5228	0	57381	57381	3978	1145	347
2007	108275	-49807	58468	3137	0	61604	61604	3882	1069	310
2008	120726	-55534	65192	1046	0	66237	66237	3795	999	278
2009	132943	-61154	71789	0	0	71788	71788	3739	942	251
2010	144988	-66695	78293	0	0	78292	78292	3707	893	228
2011	157974	-72668	85306	0	0	85305	85305	3672	846	207
2012	171970	-79106	92864	0	0	92863	92863	3634	801	188
2013	187052	-86044	101008	0	0	101007	101007	3593	757	170
2014	203302	-93519	109783	0	0	109782	109782	3550	716	154
2015	220808	-101572	119236	0	0	119235	119235	3521	676	136
TOTALS	1777100	-817463	959637	555466	55545	1570627	1027253	-171451	-206102	-197377

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASE : HTSH
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-REPT (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-13108	0	0	-13108	0	0	-131	0	0	-131
1980	-46941	0	0	-46941	0	0	-734	0	0	-734
1981	-77851	0	0	-77851	0	0	-1997	0	0	-1997
1982	-128982	0	0	-128982	0	0	-4105	0	0	-4105
1983	-155262	0	0	-155262	0	0	-7030	0	0	-7030
1984	-110754	0	0	-110754	0	0	-9830	0	0	-9830
1985	-24568	0	0	-24568	0	0	-11380	0	0	-11380
1986	0	0	0	0	-38750	-7319	-11853	-49375	52817	-50480
1987	0	0	0	0	-40649	-7758	-11853	-49986	56514	-46732
1988	0	0	0	0	-42641	-8224	-11853	-42869	60470	-45117
1989	0	0	0	0	-44730	-8717	-11853	-40778	64703	-41375
1990	0	0	0	0	-46922	-9240	-11853	-38687	69212	-37470
1991	0	0	0	0	-49221	-9794	-11853	-36596	74079	-33386
1992	0	0	0	0	-51633	-10382	-11853	-34504	79264	-29109
1993	0	0	0	0	-54163	-11005	-11853	-32413	84813	-24622
1994	0	0	0	0	-56817	-11665	-11853	-30322	90749	-19908
1995	0	0	0	0	-59601	-12365	-11853	-28231	97182	-14948
1996	0	0	0	0	-62521	-13107	-11853	-26140	103899	-9722
1997	0	0	0	0	-65585	-13894	-11853	-24049	111172	-4208
1998	0	0	0	0	-68798	-14727	-11853	-21957	118954	1617
1999	0	0	0	0	-72169	-15611	-11853	-19866	127281	7780
2000	0	0	0	0	-75706	-16548	-11853	-17775	136190	14308
2001	0	0	0	0	-79415	-17540	-11853	-15684	145724	21230
2002	0	0	0	0	-83307	-18593	-11853	-13593	155924	28578
2003	0	0	0	0	-87389	-19708	-11853	-11501	166839	36386
2004	0	0	0	0	-91671	-20891	-11853	-9410	178518	44692
2005	0	0	0	0	-96163	-22144	-11853	-7319	191014	53534
2006	0	0	0	0	-100875	-23473	-11853	-5228	204385	62955
2007	0	0	0	0	-105817	-24881	-11853	-3137	218692	73002
2008	0	0	0	0	-111002	-26374	-11853	-1046	234001	83724
2009	0	0	0	0	-116442	-27957	-11853	0	250381	94128
2010	0	0	0	0	-122147	-29634	-11853	0	267907	104271
2011	0	0	0	0	-128132	-31412	-11853	0	286661	115262
2012	0	0	0	0	-134411	-33297	-11853	0	306727	127165
2013	0	0	0	0	-140997	-35295	-11853	0	328168	140052
2014	0	0	0	0	-147996	-37412	-11853	0	351172	153999
2015	14121	0	0	14121	-155153	-39657	-11853	0	375754	169089
TOTALS	-543344	0	0	-543345	-2530730	-578627	-390811	-555466	4989136	933501

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : HTGR
150% FUEL COST

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YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	-131	60	-71	0	1110	1038	-12069	-10972	-10405	-10058
1980	-734	338	-396	0	4694	4297	-42643	-35242	-32204	-29613
1981	-1997	919	-1078	0	7785	6706	-71144	-53452	-46778	-41171
1982	-4105	1888	-2217	0	12898	10680	-118301	-80801	-67699	-57051
1983	-7030	3234	-3796	0	15526	11729	-143532	-89122	-71361	-57682
1984	-9830	4522	-5308	0	11075	5766	-104987	-59262	-45389	-35160
1985	-11180	5235	-6145	0	2457	-3688	-28256	-14500	-10672	-7886
1986	-54480	25060	-29420	49375	0	19954	19954	9308	6522	4640
1987	-48732	22416	-26316	44986	0	18669	18669	7916	5306	3617
1988	-45117	20753	-24364	42869	0	18504	18504	7133	4573	2987
1989	-41375	19032	-22343	40778	0	18434	18434	6460	3961	2480
1990	-37470	17236	-20234	38687	0	18452	18452	5878	3428	2069
1991	-33386	15357	-18029	36596	0	18566	18566	5377	3116	1734
1992	-29109	13389	-15720	34504	0	18783	18783	4945	2854	1462
1993	-24622	11326	-13296	32413	0	19116	19116	4575	2508	1240
1994	-19908	9157	-10751	30322	0	19570	19570	4258	2290	1058
1995	-14948	6876	-8072	29231	0	20158	20158	3987	1372	908
1996	-9722	4472	-5250	26140	0	20889	20889	3756	1087	784
1997	-4208	1935	-2273	24049	0	21775	21775	3599	1029	681
1998	1617	-744	873	21957	0	22829	22829	3392	1304	594
1999	7780	-3579	4201	19866	0	24066	24066	3251	1278	522
2000	14308	-6582	7726	17775	0	25500	25500	3132	1177	461
2001	21230	-9766	11464	15684	0	27147	27147	3031	1090	409
2002	28578	-13146	15432	13593	0	29024	29024	2946	1013	364
2003	36386	-16736	19648	11501	0	31148	31148	2874	945	326
2004	44692	-20558	24134	9410	0	33543	33543	2813	885	292
2005	53534	-24625	28909	7319	0	36227	36227	2762	831	263
2006	62955	-28959	33996	5228	0	39223	39223	2719	782	237
2007	73002	-33581	39421	3137	0	42557	42557	2682	738	214
2008	83724	-38513	45211	1046	0	46256	46256	2650	698	194
2009	94128	-43299	50829	0	0	50828	50828	2647	667	177
2010	104271	-47965	56306	0	0	56305	56305	2666	642	164
2011	115262	-53020	62242	0	0	62241	62241	2679	617	151
2012	127165	-58496	68669	0	0	68668	68668	2687	592	139
2013	140052	-64424	75628	0	0	75627	75627	2690	567	127
2014	153999	-70840	83159	0	0	83158	83158	2689	542	116
2015	169089	-77781	91308	0	0	91307	105428	3099	568	123
TOTALS	933501	-429411	504077	555466	55545	1115087	571713	-224739	-231418	-210044

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASE : MTGP
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-13108	0	0	-13108	0	0	-131	0	0	-131
1980	-46941	0	0	-46941	0	0	-734	0	0	-734
1981	-77451	0	0	-77451	0	0	-1997	0	0	-1997
1982	-128982	0	0	-128982	0	0	-4105	0	0	-4105
1983	-155262	0	0	-155262	0	0	-7030	0	0	-7030
1984	-110754	0	0	-110754	0	0	-9830	0	0	-9830
1985	-24568	0	0	-24568	0	0	-11380	0	0	-11380
1986	0	0	0	0	-51466	-7319	-11853	-49375	52817	-67396
1987	0	0	0	0	-54198	-7758	-11853	-44986	56514	-62281
1988	0	0	0	0	-56853	-8224	-11853	-42869	60470	-59329
1989	0	0	0	0	-59639	-8717	-11853	-40778	64703	-56285
1990	0	0	0	0	-62561	-9240	-11853	-38687	69232	-53110
1991	0	0	0	0	-65627	-9794	-11853	-36596	74079	-49792
1992	0	0	0	0	-68843	-10382	-11853	-34504	79264	-46319
1993	0	0	0	0	-72216	-11005	-11853	-32413	84813	-42675
1994	0	0	0	0	-75755	-11665	-11853	-30322	90749	-38846
1995	0	0	0	0	-79467	-12365	-11853	-28231	97102	-34814
1996	0	0	0	0	-83360	-13107	-11853	-26140	103899	-30562
1997	0	0	0	0	-87445	-13894	-11853	-24049	111172	-26069
1998	0	0	0	0	-91730	-14727	-11853	-21957	118954	-21314
1999	0	0	0	0	-96225	-15611	-11853	-19866	127281	-16274
2000	0	0	0	0	-100940	-16548	-11853	-17775	136190	-10925
2001	0	0	0	0	-105886	-17540	-11853	-15684	145724	-5240
2002	0	0	0	0	-111074	-18593	-11853	-13593	155924	810
2003	0	0	0	0	-116517	-19708	-11853	-11501	166819	7258
2004	0	0	0	0	-122226	-20891	-11853	-9410	178518	14136
2005	0	0	0	0	-128215	-22144	-11853	-7319	191014	21481
2006	0	0	0	0	-134498	-23473	-11853	-5228	204385	29332
2007	0	0	0	0	-141088	-24881	-11853	-3137	218692	37731
2008	0	0	0	0	-148001	-26374	-11853	-1046	234001	46725
2009	0	0	0	0	-155253	-27957	-11853	0	250381	55316
2010	0	0	0	0	-162861	-29634	-11853	0	267907	63558
2011	0	0	0	0	-170841	-31412	-11853	0	286661	72553
2012	0	0	0	0	-179212	-33297	-11853	0	306727	82363
2013	0	0	0	0	-187994	-35295	-11853	0	328198	93055
2014	0	0	0	0	-197205	-37412	-11853	0	351172	104700
2015	14121	0	0	14121	-206868	-39657	-11853	0	375754	117374
TOTALS	-543344	0	0	-543345	-3374262	-578627	-390811	-555466	4989136	89968

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: URANGE COGENERATION
CASE : HTGP
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	-131	60	-71	0	1110	1038	-12069	-10972	-10495	-10058
1980	-734	338	-396	0	4694	4297	-42643	-35242	-32244	-29613
1981	-1997	919	-1078	0	7785	6706	-71144	-53452	-46778	-41171
1982	-4105	1888	-2217	0	12998	10680	-118301	-80801	-67639	-57051
1983	-7030	3234	-3796	0	15526	11729	-143532	-89122	-71361	-57682
1984	-9830	4522	-5308	0	11075	5766	-104987	-59262	-45389	-35160
1985	-11380	5235	-6145	0	2457	-3648	-28256	-14500	-10622	-7886
1986	-67396	31002	-36394	49375	0	12980	12980	6054	4242	3018
1987	-62281	28649	-33632	44986	0	11353	11353	4814	3226	2199
1988	-54320	27291	-32038	42869	0	10830	10830	4174	2676	1748
1989	-56285	25890	-30395	40778	0	10382	10382	3638	2231	1396
1990	-53110	24430	-28680	38687	0	10006	10006	3187	1849	1121
1991	-49792	22904	-26888	36596	0	9707	9707	2811	1577	906
1992	-46319	21306	-25013	34504	0	9490	9490	2498	1340	738
1993	-42675	19630	-23045	32413	0	9367	9367	2241	1150	607
1994	-38846	17869	-20977	30322	0	9344	9344	2033	968	504
1995	-34814	16014	-18800	28231	0	9430	9430	1865	875	424
1996	-30562	14058	-16504	26140	0	9635	9635	1732	778	361
1997	-26069	11991	-14078	24049	0	9970	9970	1629	700	311
1998	-21314	9804	-11510	21957	0	10446	10446	1552	637	271
1999	-16274	7486	-8788	19866	0	11077	11077	1496	588	240
2000	-11925	5025	-5900	17775	0	11874	11874	1458	548	214
2001	-5240	2410	-2830	15684	0	12853	12853	1434	515	193
2002	810	-373	437	13593	0	14029	14029	1423	489	175
2003	7258	-3339	3919	11501	0	15419	15419	1422	467	161
2004	14136	-6503	7633	9410	0	17042	17042	1429	409	148
2005	21481	-9881	11600	7319	0	18918	18918	1442	434	137
2006	29332	-13493	15839	5228	0	21066	21066	1460	420	127
2007	37731	-17356	20375	3137	0	23511	23511	1481	407	118
2008	46725	-21493	25232	1046	0	26277	26277	1505	396	110
2009	55316	-25445	29871	0	0	29870	29870	1555	391	104
2010	63558	-29237	34321	0	0	34320	34320	1624	361	99
2011	72553	-33374	39179	0	0	39178	39178	1686	388	95
2012	82363	-37887	44476	0	0	44475	44475	1740	383	89
2013	93055	-42805	50250	0	0	50249	50249	1787	376	84
2014	104700	-48162	56538	0	0	56537	56537	1828	368	79
2015	117374	-53992	63382	0	0	63381	77502	2278	439	90
TOTALS	89968	-41385	48569	555466	55545	659579	116205	-278027	-258727	-222704

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION

CASE : CMSS

90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,070)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS REFCGR TAX (5+6+7+8+9)
1979	-10293	0	0	-10293	0	0	-103	0	0	-103
1980	-17437	0	0	-17437	0	0	-382	0	0	-382
1981	-37315	0	0	-37315	0	0	-937	0	0	-937
1982	-74873	0	0	-74873	0	0	-2078	0	0	-2078
1983	-133523	0	0	-133523	0	0	-4204	0	0	-4204
1984	-188597	0	0	-188597	0	0	-7509	0	0	-7509
1985	-84304	0	-2268	-86572	0	0	-10388	0	0	-10388
1986	0	-6396	-136	-6532	-19907	-7587	-11439	-48386	7617	-79682
1987	0	-6844	-144	-6988	-20882	-8042	-11439	-44085	8172	-76277
1988	0	-7323	-153	-7476	-21906	-8525	-11439	-42011	8704	-75136
1989	0	-7835	-162	-7997	-22979	-9036	-11439	-39961	9356	-74060
1990	0	-8384	-172	-8556	-24105	-9578	-11439	-37912	10011	-73024
1991	0	-8971	-182	-9153	-25286	-10153	-11439	-35863	10711	-72030
1992	0	-9599	-193	-9792	-26525	-10762	-11439	-33813	11461	-71079
1993	0	-10271	-205	-10475	-27825	-11408	-11439	-31764	12263	-70173
1994	0	-10990	-217	-11206	-29188	-12093	-11439	-29715	13122	-69313
1995	0	-11759	-230	-11989	-30619	-12818	-11439	-27666	14040	-68501
1996	0	-12582	-244	-12826	-32119	-13587	-11439	-25616	15023	-67738
1997	0	-13463	-258	-13721	-33693	-14402	-11439	-23567	16075	-67026
1998	0	-14405	-274	-14679	-35344	-15267	-11439	-21518	17200	-66367
1999	0	-15413	-290	-15704	-37076	-16183	-11439	-19468	18404	-65761
2000	0	-16492	-308	-16800	-38892	-17153	-11439	-17419	19602	-65211
2001	0	-17647	-326	-17973	-40798	-18183	-11439	-15370	21071	-64719
2002	0	-18882	-346	-19228	-42797	-19274	-11439	-13320	22546	-64284
2003	0	-20204	-366	-20570	-44894	-20430	-11439	-11271	24124	-63910
2004	0	-21618	-388	-22006	-47094	-21656	-11439	-9222	25813	-63598
2005	0	-23131	-412	-23543	-49401	-22955	-11439	-7173	27619	-63349
2006	0	-24751	-436	-25187	-51822	-24333	-11439	-5123	29553	-63164
2007	0	-26483	-463	-26946	-54361	-25792	-11439	-3074	31621	-63045
2008	0	-28337	-490	-28827	-57025	-27340	-11439	-1025	33815	-62994
2009	0	-30320	-520	-30840	-59819	-28980	-11439	0	36203	-64035
2010	0	-32443	-551	-32994	-62751	-30719	-11439	0	38718	-66171
2011	0	-34714	-584	-35298	-65825	-32562	-11439	0	41449	-68377
2012	0	-37144	-619	-37763	-69051	-34516	-11439	0	44351	-70655
2013	0	-39744	-656	-40400	-72434	-36587	-11439	0	47455	-73005
2014	0	-42526	-696	-43222	-75994	-38782	-11439	0	50777	-75428
2015	14121	-45503	12288	-19092	-79707	-41109	-11439	0	54312	-77923
TOTALS	-532220	-604171	0	-1136393	-1300109	-599814	-368767	-544342	721397	-2091636

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CWS
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.45*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	-103	47	-56	0	828	771	-9521	-8655	-8279	-7934
1980	-382	176	-206	0	1744	1537	-15899	-13140	-12022	-11041
1981	-937	431	-506	0	3732	3225	-34089	-25612	-22414	-19727
1982	-2075	956	-1122	0	7487	6364	-68508	-46792	-39170	-33038
1983	-4204	1934	-2270	0	13352	11081	-122441	-76026	-60875	-49206
1984	-7509	3454	-4055	0	18860	14804	-173792	-98101	-75135	-58203
1985	-10388	4779	-5609	0	8430	2820	-83751	-42978	-31485	-23373
1986	-79682	36653	-43029	48386	0	5356	-1175	-548	-384	-273
1987	-76277	35087	-41190	44065	0	2894	-4093	-1736	-1163	-793
1988	-75136	34562	-40574	42011	0	1436	-6039	-2328	-1493	-975
1989	-74060	34067	-39993	39961	0	-32	-8029	-2814	-1726	-1081
1990	-73024	33590	-39434	37912	0	-1522	-10078	-3211	-1884	-1130
1991	-72030	33133	-38897	35863	0	-3034	-12187	-3530	-1981	-1139
1992	-71079	32696	-38383	33813	0	-4570	-14362	-3782	-2030	-1119
1993	-70173	32279	-37894	31764	0	-6130	-16605	-3975	-2041	-1078
1994	-69313	31883	-37430	29715	0	-7715	-18921	-4118	-2022	-1023
1995	-68501	31510	-36991	27666	0	-9325	-21314	-4217	-1981	-961
1996	-67738	31159	-36579	25616	0	-10963	-23789	-4279	-1922	-894
1997	-67026	30832	-36194	23567	0	-12627	-26348	-4308	-1881	-825
1998	-66367	30526	-35839	21518	0	-14321	-29000	-4311	-1772	-756
1999	-65761	30250	-35511	19468	0	-16043	-31747	-4290	-1687	-690
2000	-65211	29997	-35214	17419	0	-17795	-34595	-4250	-1598	-627
2001	-64719	29770	-34949	15370	0	-19579	-37552	-4194	-1509	-567
2002	-64284	29570	-34714	13320	0	-21394	-40622	-4124	-1419	-511
2003	-63910	29396	-34512	11271	0	-23241	-43811	-4044	-1331	-459
2004	-63598	29255	-34343	9222	0	-25121	-47127	-3954	-1245	-412
2005	-63349	29140	-34209	7173	0	-27036	-50579	-3858	-1162	-366
2006	-63164	29055	-34109	5123	0	-28986	-54173	-3757	-1082	-329
2007	-63045	29000	-34045	3074	0	-30971	-57917	-3651	-1006	-293
2008	-62994	28977	-34017	1025	0	-32992	-61819	-3543	-934	-260
2009	-64035	29456	-34579	0	0	-34579	-65419	-3408	-889	-230
2010	-66171	30438	-35733	0	0	-35733	-68727	-3255	-785	-201
2011	-68377	31453	-36924	0	0	-36924	-72222	-3110	-717	-176
2012	-70655	32501	-38154	0	0	-38154	-75917	-2972	-656	-154
2013	-73005	33582	-39423	0	0	-39423	-79823	-2840	-599	-135
2014	-75428	34696	-40732	0	0	-40732	-83954	-2716	-548	-118
2015	-77923	35844	-42079	0	0	-42079	-88171	-2599	-507	-92
TOTALS	-2091836	962138	-1129498	544342	54433	-530723	-1867116	-414206	-285093	-220155

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CNSS
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,070)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,049)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-10293	0	0	-10293	0	0	-103	0	0	-103
1980	-17437	0	0	-17437	0	0	-382	0	0	-382
1981	-37315	0	0	-37315	0	0	-937	0	0	-937
1982	-74873	0	0	-74873	0	0	-2078	0	0	-2078
1983	-133523	0	0	-133523	0	0	-4204	0	0	-4204
1984	-188597	0	0	-188597	0	0	-7509	0	0	-7509
1985	-84304	0	-2268	-86572	0	0	-10388	0	0	-10388
1986	0	-7107	-136	-7243	-22119	-7587	-11439	-48386	7637	-81894
1987	0	-7604	-144	-7749	-23203	-8042	-11439	-44085	8172	-78597
1988	0	-8137	-153	-8290	-24340	-8525	-11439	-42011	8744	-77570
1989	0	-8706	-162	-8868	-25532	-9036	-11439	-39961	9356	-76613
1990	0	-9316	-172	-9488	-26784	-9578	-11439	-37912	10011	-75702
1991	0	-9968	-182	-10150	-28096	-10153	-11439	-35863	10711	-74839
1992	0	-10666	-193	-10859	-29473	-10762	-11439	-33813	11461	-74026
1993	0	-11412	-205	-11617	-30917	-11408	-11439	-31764	12243	-73264
1994	0	-12211	-217	-12428	-32432	-12093	-11439	-29715	13122	-72556
1995	0	-13066	-230	-13296	-34021	-12818	-11439	-27666	14040	-71903
1996	0	-13931	-244	-14224	-35688	-13587	-11439	-25616	15023	-71307
1997	0	-14959	-258	-15218	-37437	-14402	-11439	-23567	16075	-70770
1998	0	-16006	-274	-16280	-39271	-15267	-11439	-21518	17200	-70294
1999	0	-17127	-290	-17417	-41195	-16183	-11439	-19468	18404	-69881
2000	0	-18326	-308	-18633	-43214	-17153	-11439	-17419	19692	-69533
2001	0	-19606	-326	-19935	-45331	-18183	-11439	-15370	21071	-69252
2002	0	-20981	-346	-21327	-47552	-19274	-11439	-13320	22546	-69040
2003	0	-22450	-366	-22816	-49883	-20430	-11439	-11271	24124	-68899
2004	0	-24021	-388	-24410	-52327	-21656	-11439	-9222	25813	-68831
2005	0	-25703	-412	-26114	-54891	-22955	-11439	-7173	27619	-68838
2006	0	-27502	-436	-27938	-57580	-24333	-11439	-5123	29553	-68922
2007	0	-29427	-463	-29890	-60402	-25792	-11439	-3074	31621	-69086
2008	0	-31487	-490	-31977	-63362	-27340	-11439	-1025	33835	-69330
2009	0	-33691	-520	-34211	-66466	-28980	-11439	0	36203	-70682
2010	0	-36049	-551	-36600	-69723	-30719	-11439	0	38738	-73144
2011	0	-38573	-584	-39157	-73140	-32562	-11439	0	41449	-75692
2012	0	-41273	-619	-41892	-76723	-34516	-11439	0	44351	-78328
2013	0	-44162	-656	-44818	-80483	-36587	-11439	0	47455	-81054
2014	0	-47253	-696	-47949	-84427	-38782	-11439	0	50777	-83871
2015	14121	-50561	12288	-24151	-88563	-41109	-11439	0	54332	-86780
TOTALS	-532220	-671333	0	-1203555	-1444573	-599814	-368767	-544342	721397	-2236100

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CNSS
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DF=.10)	(19) PRESENT WORTH-NCF (DF=.15)	(20) PRESENT WORTH-NCF (DF=.20)
1979	-103	47	-56	0	828	771	-9521	-8655	-8279	-7934
1980	-382	176	-206	0	1744	1537	-15899	-13140	-12022	-11041
1981	-937	431	-506	0	3732	3225	-34089	-25612	-22414	-19727
1982	-2078	956	-1122	0	7487	6364	-68508	-46792	-39170	-33038
1983	-4204	1934	-2270	0	13352	11081	-122441	-76026	-60875	-49206
1984	-7509	3454	-4055	0	18860	14804	-173792	-98101	-75135	-58203
1985	-10388	4779	-5609	0	8430	2820	-83751	-42978	-31445	-23373
1986	-81894	37671	-44223	48386	0	4162	-3080	-1437	-1067	-716
1987	-78597	36154	-42443	44085	0	1641	-6107	-2590	-1736	-1184
1988	-77570	35682	-41888	42011	0	122	-8167	-3149	-2019	-1319
1989	-76613	35242	-41371	39961	0	-1410	-10278	-3602	-2209	-1383
1990	-75702	34823	-40879	37912	0	-2967	-12455	-3969	-2328	-1397
1991	-74839	34426	-40413	35863	0	-4550	-14700	-4258	-2389	-1374
1992	-74026	34052	-39974	33813	0	-6161	-17020	-4482	-2465	-1326
1993	-73264	33701	-39563	31764	0	-7799	-19416	-4648	-2386	-1260
1994	-72556	33375	-39181	29715	0	-9466	-21894	-4765	-2300	-1184
1995	-71903	33075	-38828	27666	0	-11162	-24458	-4839	-2273	-1102
1996	-71307	32801	-38506	25616	0	-12890	-27114	-4877	-2191	-1018
1997	-70770	32554	-38216	23567	0	-14649	-29867	-4883	-2099	-935
1998	-70294	32335	-37959	21518	0	-16441	-32721	-4864	-1949	-853
1999	-69881	32145	-37736	19468	0	-18268	-35685	-4822	-1896	-776
2000	-69533	31985	-37548	17419	0	-20129	-38762	-4762	-1791	-702
2001	-69252	31855	-37397	15370	0	-22027	-41962	-4686	-1686	-633
2002	-69040	31758	-37282	13320	0	-23962	-45289	-4598	-1582	-570
2003	-68899	31693	-37206	11271	0	-25935	-48751	-4500	-1481	-511
2004	-68831	31662	-37169	9222	0	-27947	-52357	-4393	-1383	-457
2005	-68838	31665	-37173	7173	0	-30000	-56114	-4280	-1249	-408
2006	-68922	31704	-37218	5123	0	-32095	-60033	-4163	-1149	-364
2007	-69086	31779	-37307	3074	0	-34233	-64123	-4042	-1114	-324
2008	-69330	31891	-37439	1025	0	-36414	-68391	-3919	-1033	-288
2009	-70682	32513	-38169	0	0	-38169	-72380	-3771	-951	-254
2010	-73144	33646	-39498	0	0	-39498	-76098	-3604	-849	-223
2011	-75692	34818	-40874	0	0	-40874	-80031	-3446	-765	-195
2012	-78328	36030	-42298	0	0	-42298	-84190	-3295	-727	-171
2013	-81054	37284	-43770	0	0	-43770	-88588	-3152	-665	-150
2014	-83871	38580	-45291	0	0	-45291	-93240	-3016	-609	-132
2015	-86780	39918	-46862	0	0	-46862	-71013	-2088	-403	-83
TOTALS	-2236100	1028594	-1207505	544342	54433	-608730	-1812285	-430185	-296213	-223802

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CNSS
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$.070)	(3) WORKING CAPITAL-NET (ER \$.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$.049)	(6) OTHER OPER EXPENSES (ER \$.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-10293	0	0	-10293	0	0	-103	0	0	-103
1980	-17437	0	0	-17437	0	0	-382	0	0	-382
1981	-37315	0	0	-37315	0	0	-937	0	0	-937
1982	-74873	0	0	-74873	0	0	-2078	0	0	-2078
1983	-133523	0	0	-133523	0	0	-4204	0	0	-4204
1984	-188597	0	0	-188597	0	0	-7509	0	0	-7509
1985	-84304	0	-2268	-86572	0	0	-10388	0	0	-10388
1986	0	-10660	-136	-10796	-33178	-7587	-11439	-48386	7637	-92953
1987	0	-11406	-144	-11550	-34804	-8042	-11439	-44085	8172	-90198
1988	0	-12205	-153	-12358	-36509	-8525	-11439	-42011	8744	-89740
1989	0	-13059	-162	-13221	-38298	-9036	-11439	-39961	9356	-89379
1990	0	-13973	-172	-14145	-40175	-9578	-11439	-37912	10011	-89093
1991	0	-14951	-182	-15133	-42143	-10153	-11439	-35863	10711	-88887
1992	0	-15998	-193	-16191	-44208	-10762	-11439	-33813	11461	-88762
1993	0	-17118	-205	-17322	-46374	-11408	-11439	-31764	12263	-88722
1994	0	-18316	-217	-18533	-48647	-12093	-11439	-29715	13122	-88771
1995	0	-19598	-230	-19828	-51030	-12818	-11439	-27666	14040	-88913
1996	0	-20970	-244	-21214	-53531	-13587	-11439	-25616	15023	-89150
1997	0	-22438	-258	-22696	-56154	-14402	-11439	-23567	16075	-89487
1998	0	-24008	-274	-24282	-58906	-15267	-11439	-21518	17200	-89929
1999	0	-25689	-290	-25979	-61792	-16183	-11439	-19468	18444	-90478
2000	0	-27487	-308	-27795	-64820	-17153	-11439	-17419	19692	-91139
2001	0	-29411	-326	-29737	-67996	-18183	-11439	-15370	21071	-91916
2002	0	-31470	-346	-31816	-71328	-19274	-11439	-13320	22546	-92815
2003	0	-33673	-366	-34039	-74823	-20430	-11439	-11271	24124	-93839
2004	0	-36030	-388	-36419	-78489	-21656	-11439	-9222	25813	-94993
2005	0	-38552	-412	-38964	-82335	-22955	-11439	-7173	27619	-96282
2006	0	-41251	-436	-41687	-86369	-24333	-11439	-5123	29553	-97711
2007	0	-44138	-463	-44601	-90602	-25792	-11439	-3074	31621	-99285
2008	0	-47228	-490	-47718	-95041	-27340	-11439	-1025	33815	-101010
2009	0	-50534	-520	-51054	-99698	-28980	-11439	0	36203	-103914
2010	0	-54071	-551	-54622	-104583	-30719	-11439	0	38718	-108004
2011	0	-57856	-584	-58440	-109708	-32562	-11439	0	41449	-112260
2012	0	-61906	-619	-62525	-115083	-34516	-11439	0	44351	-116688
2013	0	-66240	-656	-66896	-120723	-36587	-11439	0	47495	-121293
2014	0	-70877	-696	-71572	-126638	-38782	-11439	0	50777	-126082
2015	14121	-75838	12288	-49429	-132843	-41109	-11439	0	54332	-131060
TOTALS	-532220	-1006952	0	-1539171	-2166827	-599814	-368767	-544342	721397	-2958354

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: GRANGE COGENERATION
CASE : CASS
150X FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-ACF (DR#10)	(19) PRESENT WORTH-ACF (DR#15)	(20) PRESENT WORTH-ACF (DR#20)
1979	-103	47	-56	0	828	771	-9521	-8655	-8279	-7930
1980	-382	176	-206	0	1744	1537	-15899	-13140	-12022	-11041
1981	-937	431	-506	0	3732	3225	-34089	-25612	-22414	-19727
1982	-2078	956	-1122	0	7487	6364	-68508	-46792	-39170	-33038
1983	-4204	1934	-2270	0	13352	11081	-122441	-76026	-60875	-49206
1984	-7509	3454	-4055	0	18860	14804	-173792	-98101	-75135	-58203
1985	-10386	4779	-5609	0	8430	2820	-83751	-42978	-31485	-23373
1986	-92953	42758	-50195	48386	0	-1809	-12605	-5880	-4121	-2932
1987	-90198	41491	-48707	44085	0	-4622	-16172	-6859	-4547	-3134
1988	-69740	41280	-48460	42011	0	-6449	-18807	-7251	-4609	-3037
1989	-89379	41114	-48265	39961	0	-8304	-21525	-7544	-4627	-2897
1990	-89093	40982	-48111	37912	0	-10159	-24344	-7757	-4550	-2730
1991	-68867	40887	-48000	35863	0	-12137	-27270	-7899	-4432	-2549
1992	-68762	40830	-47932	33813	0	-14119	-30310	-7982	-4284	-2361
1993	-68722	40812	-47910	31764	0	-16146	-33468	-8012	-4113	-2172
1994	-68771	40834	-47937	29715	0	-18222	-36755	-7999	-3928	-1988
1995	-68913	40899	-48014	27666	0	-20348	-40176	-7949	-3753	-1811
1996	-89150	41009	-48141	25616	0	-22525	-43739	-7867	-3554	-1643
1997	-89487	41164	-48323	23567	0	-24756	-47452	-7759	-3334	-1485
1998	-89929	41367	-48562	21518	0	-27044	-51326	-7629	-3116	-1339
1999	-90478	41619	-48859	19468	0	-29391	-55370	-7482	-2902	-1204
2000	-91139	41923	-49216	17419	0	-31797	-59592	-7321	-2753	-1079
2001	-91916	42281	-49635	15370	0	-34265	-64002	-7148	-2571	-966
2002	-92815	42694	-50121	13320	0	-36801	-68617	-6966	-2367	-863
2003	-93839	43165	-50674	11271	0	-39403	-73442	-6778	-2231	-770
2004	-94993	43696	-51297	9222	0	-42075	-78494	-6586	-2073	-686
2005	-96282	44289	-51993	7173	0	-44820	-83784	-6391	-1925	-610
2006	-97711	44947	-52764	5123	0	-47641	-89328	-6194	-1784	-542
2007	-99285	45671	-53614	3074	0	-50540	-95141	-5998	-1652	-481
2008	-101010	46464	-54546	1025	0	-53521	-101239	-5802	-1529	-426
2009	-103914	47800	-56114	0	0	-56114	-107168	-5583	-1467	-376
2010	-108004	49681	-58323	0	0	-58323	-112945	-5309	-1260	-330
2011	-112260	51639	-60621	0	0	-60621	-119061	-5126	-1182	-290
2012	-116688	53676	-63012	0	0	-63012	-125537	-4914	-1084	-255
2013	-121293	55794	-65499	0	0	-65499	-132395	-4711	-994	-224
2014	-126082	57947	-68085	0	0	-68085	-139657	-4518	-912	-197
2015	-131060	60287	-70773	0	0	-70773	-120201	-3535	-682	-161
TOTALS	-2958354	1360827	-1597527	544342	54433	-998752	-2537923	-510072	-331813	-242026

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CNSS
200% FUEL COST

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YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$0.070)	(3) WORKING CAPITAL-NET (ER \$0.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$0.049)	(6) OTHER OPER EXPENSES (ER \$0.060)	(7) TAXES OTHER THAN INCOME DEPRECIATION (NON-CASH)	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$0.070)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	-10293	0	0	-10293	0	0	-103	0	0	-103
1980	-17437	0	0	-17437	0	0	-382	0	0	-382
1981	-37315	0	0	-37315	0	0	-937	0	0	-937
1982	-74873	0	0	-74873	0	0	-2078	0	0	-2078
1983	-133523	0	0	-133523	0	0	-4204	0	0	-4204
1984	-188597	0	0	-188597	0	0	-7509	0	0	-7509
1985	-84304	0	-2268	-86572	0	0	-10388	0	0	-10388
1986	0	-14214	-136	-14350	-44238	-7587	-11439	-88386	7637	-104013
1987	0	-15209	-144	-15353	-46406	-8042	-11439	-44085	8172	-101800
1988	0	-16274	-153	-16427	-48680	-8525	-11439	-42011	8784	-101910
1989	0	-17413	-162	-17575	-51065	-9036	-11439	-35961	9386	-102146
1990	0	-18632	-172	-18803	-53567	-9578	-11439	-37912	10011	-102486
1991	0	-19936	-182	-20118	-56192	-10153	-11439	-35863	10711	-102935
1992	0	-21331	-193	-21524	-58945	-10762	-11439	-33813	11461	-103499
1993	0	-22825	-205	-23029	-61834	-11408	-11439	-31764	12263	-104181
1994	0	-24422	-217	-24639	-64863	-12093	-11439	-29715	13122	-104988
1995	0	-26132	-230	-26362	-68042	-12818	-11439	-27666	14040	-105924
1996	0	-27961	-244	-28205	-71376	-13587	-11439	-25616	15023	-106995
1997	0	-29918	-256	-30177	-74873	-14402	-11439	-23567	16075	-108207
1998	0	-32013	-274	-32286	-78542	-15267	-11439	-21518	17200	-109565
1999	0	-34254	-290	-34544	-82390	-16183	-11439	-19468	18404	-111076
2000	0	-36651	-308	-36959	-86428	-17153	-11439	-17419	19692	-112747
2001	0	-39217	-326	-39543	-90663	-18183	-11439	-15370	21071	-114583
2002	0	-41962	-346	-42308	-95105	-19274	-11439	-13320	22506	-116592
2003	0	-44899	-366	-45265	-99765	-20430	-11439	-11271	24124	-118781
2004	0	-48042	-388	-48431	-104654	-21656	-11439	-9222	25813	-121158
2005	0	-51405	-412	-51817	-109782	-22955	-11439	-7173	27619	-123729
2006	0	-55004	-436	-55440	-115161	-24333	-11439	-5123	29543	-126503
2007	0	-58854	-463	-59317	-120864	-25792	-11439	-3074	31621	-129488
2008	0	-62974	-490	-63464	-126723	-27340	-11439	-1025	33815	-132692
2009	0	-67382	-520	-67902	-132933	-28980	-11439	0	36203	-137149
2010	0	-72099	-551	-72650	-139446	-30719	-11439	0	38718	-142867
2011	0	-77146	-584	-77730	-146279	-32562	-11439	0	41409	-148831
2012	0	-82546	-619	-83165	-153447	-34516	-11439	0	44351	-155051
2013	0	-88324	-656	-88980	-160966	-36587	-11439	0	47455	-161536
2014	0	-94507	-696	-95202	-168853	-38782	-11439	0	50777	-168297
2015	14121	-101122	12288	-74712	-177127	-41109	-11439	0	54312	-175344
TOTALS	-532220	-1342666	0	-1874886	-2889146	-599814	-368767	-544342	721397	-3680673

PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : CNSS
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH-NCF (DR=.10)	(19) PRESENT WORTH-NCF (DR=.15)	(20) PRESENT WORTH-NCF (DR=.20)
1979	-103	47	-56	0	828	771	-9521	-8655	-8279	-7934
1980	-382	176	-206	0	1744	1537	-15899	-13140	-12022	-11041
1981	-937	431	-506	0	3732	3225	-34099	-25612	-22414	-19727
1982	-2078	956	-1122	0	7487	6364	-68508	-46792	-39170	-33038
1983	-4204	1934	-2270	0	13352	11081	-122441	-76026	-60875	-49206
1984	-7509	3454	-4055	0	18860	14804	-173792	-98101	-75135	-58203
1985	-10388	4779	-5609	0	8430	2820	-83751	-42978	-31495	-23373
1986	-104013	47845	-56168	48386	0	-7782	-22132	-10325	-7235	-5147
1987	-101800	46828	-54972	44085	0	-10887	-26240	-11128	-7459	-5085
1988	-101910	46876	-55032	42011	0	-13021	-29448	-11353	-7279	-4756
1989	-102146	46987	-55159	39961	0	-15198	-32773	-11487	-7044	-4411
1990	-102486	47143	-55343	37912	0	-17431	-36234	-11545	-6772	-4064
1991	-102935	47350	-55585	35863	0	-19722	-39840	-11540	-6475	-3724
1992	-103499	47609	-55890	33813	0	-22077	-43601	-11482	-6162	-3396
1993	-104181	47923	-56258	31764	0	-24494	-47523	-11377	-5840	-3085
1994	-104988	48294	-56694	29715	0	-26979	-51618	-11234	-5516	-2792
1995	-105924	48724	-57200	27666	0	-29534	-55896	-11059	-5194	-2519
1996	-106995	49217	-57778	25615	0	-32162	-60367	-10858	-4878	-2267
1997	-108207	49775	-58432	23567	0	-34865	-65042	-10635	-4570	-2036
1998	-109565	50399	-59166	21512	0	-37648	-69934	-10395	-4273	-1824
1999	-111076	51095	-59981	19468	0	-40513	-75057	-10142	-3988	-1631
2000	-112747	51863	-60884	17419	0	-43465	-80424	-9880	-3716	-1457
2001	-114583	52708	-61875	15370	0	-46505	-86048	-9610	-3457	-1299
2002	-116592	53632	-62960	13320	0	-49640	-91948	-9335	-3212	-1157
2003	-118781	54639	-64142	11271	0	-52871	-98137	-9058	-2991	-1029
2004	-121158	55732	-65426	9222	0	-56204	-104635	-8779	-2744	-914
2005	-123729	56915	-66814	7173	0	-59641	-111458	-8502	-2560	-811
2006	-126503	58191	-68312	5123	0	-63189	-118629	-8226	-2369	-720
2007	-129488	59564	-69924	3074	0	-66850	-126167	-7953	-2191	-638
2008	-132692	61038	-71654	1025	0	-70629	-134093	-7685	-2025	-565
2009	-137149	63088	-74061	0	0	-74061	-141963	-7396	-1864	-498
2010	-142867	65718	-77149	0	0	-77149	-149799	-7095	-1711	-438
2011	-148831	68462	-80369	0	0	-80369	-158099	-6807	-1570	-385
2012	-155051	71323	-83728	0	0	-83728	-166893	-6533	-1441	-339
2013	-161536	74306	-87230	0	0	-87230	-176210	-6270	-1323	-298
2014	-168297	77416	-90881	0	0	-90881	-186083	-6020	-1215	-263
2015	-175344	80658	-94686	0	0	-94686	-196398	-5982	-962	-199
TOTALS	-3680673	1493097	-1987577	544342	54433	-1388802	-3263690	-589974	-367414	-260252

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: CHANCE COGENERATION
CASE : EXIST. PLANTS
90% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER 0.000)	(3) WORKING CAPITAL-NET (ER 0.060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER 0.070)	(6) OTHER OPER EXPENSES (ER 0.060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER 0.000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-22947	-22947	0	0	0	0	0	0
1986	0	0	-1377	-1377	-119853	-6718	0	0	0	-126571
1987	0	0	-1459	-1459	-128243	-7121	0	0	0	-135364
1988	0	0	-1547	-1547	-137220	-7548	0	0	0	-144768
1989	0	0	-1640	-1640	-146825	-8001	0	0	0	-154826
1990	0	0	-1738	-1738	-157103	-8481	0	0	0	-165584
1991	0	0	-1842	-1842	-168100	-8990	0	0	0	-177090
1992	0	0	-1953	-1953	-179867	-9530	0	0	0	-189397
1993	0	0	-2070	-2070	-192458	-10101	0	0	0	-202559
1994	0	0	-2194	-2194	-205930	-10707	0	0	0	-216637
1995	0	0	-2326	-2326	-220345	-11350	0	0	0	-231699
1996	0	0	-2466	-2466	-235769	-12031	0	0	0	-247800
1997	0	0	-2614	-2614	-252273	-12753	0	0	0	-265026
1998	0	0	-2770	-2770	-269932	-13518	0	0	0	-283450
1999	0	0	-2937	-2937	-288827	-14329	0	0	0	-303156
2000	0	0	-3113	-3113	-309045	-15189	0	0	0	-324234
2001	0	0	-3300	-3300	-330678	-16100	0	0	0	-346778
2002	0	0	-3498	-3498	-353826	-17066	0	0	0	-370892
2003	0	0	-3707	-3707	-378594	-18090	0	0	0	-396684
2004	0	0	-3930	-3930	-405095	-19175	0	0	0	-424271
2005	0	0	-4166	-4166	-433452	-20326	0	0	0	-453778
2006	0	0	-4416	-4416	-463793	-21546	0	0	0	-485339
2007	0	0	-4681	-4681	-496259	-22838	0	0	0	-519097
2008	0	0	-4961	-4961	-530997	-24209	0	0	0	-555206
2009	0	0	-5259	-5259	-568167	-25661	0	0	0	-593828
2010	0	0	-5575	-5575	-607939	-27201	0	0	0	-635139
2011	0	0	-5909	-5909	-650494	-28833	0	0	0	-679327
2012	0	0	-6264	-6264	-696029	-30563	0	0	0	-726592
2013	0	0	-6640	-6640	-744751	-32397	0	0	0	-777147
2014	0	0	-7038	-7038	-796883	-34340	0	0	0	-831224
2015	0	0	124335	124335	-852665	-36401	0	0	0	-889066
TOTALS	0	0	0	-2	-11321411	-531113	0	0	0	-11852524

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANTS
90% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR\$,10)	(19) PRESENT WORTH=NCF (DR\$,15)	(20) PRESENT WORTH=NCF (DR\$,20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-22947	-11775	-8627	-6404
1986	-126571	58222	-68349	0	0	-68349	-69726	-32928	-22794	-16216
1987	-135364	62267	-73097	0	0	-73097	-74556	-31619	-21193	-14449
1988	-144768	66593	-78175	0	0	-78175	-79722	-30736	-19706	-12876
1989	-154826	71220	-83606	0	0	-83606	-85246	-29878	-18323	-11473
1990	-165584	76168	-89416	0	0	-89416	-91154	-29044	-17037	-10224
1991	-177090	81461	-95629	0	0	-95629	-97471	-28234	-15842	-9110
1992	-189397	87122	-102275	0	0	-102275	-104228	-27446	-14730	-8118
1993	-202559	93177	-109382	0	0	-109382	-111452	-26681	-13697	-7234
1994	-216637	99653	-116984	0	0	-116984	-119178	-25937	-12736	-6446
1995	-231695	106579	-125116	0	0	-125116	-127442	-25214	-11843	-5744
1996	-247800	113987	-133813	0	0	-133813	-136279	-24511	-11012	-5119
1997	-265026	121911	-143115	0	0	-143115	-145729	-23828	-10240	-4561
1998	-283450	130386	-153064	0	0	-153064	-155834	-23164	-9522	-4065
1999	-303156	139451	-163705	0	0	-163705	-166642	-22518	-8854	-3622
2000	-324234	149147	-175087	0	0	-175087	-178200	-21891	-8233	-3228
2001	-346778	159518	-187260	0	0	-187260	-190560	-21281	-7656	-2876
2002	-370892	170610	-200282	0	0	-200282	-203780	-20689	-7119	-2563
2003	-396684	182474	-214210	0	0	-214210	-217917	-20113	-6620	-2284
2004	-424271	195164	-229107	0	0	-229107	-233037	-19553	-6156	-2036
2005	-453778	208737	-245041	0	0	-245041	-249207	-19009	-5724	-1814
2006	-485339	223255	-262084	0	0	-262084	-266500	-18480	-5323	-1617
2007	-519097	238784	-280313	0	0	-280313	-284994	-17966	-4950	-1441
2008	-555206	255394	-299812	0	0	-299812	-304773	-17466	-4603	-1284
2009	-593828	273160	-320668	0	0	-320668	-325927	-16980	-4280	-1144
2010	-635139	292164	-342975	0	0	-342975	-348550	-16508	-3980	-1020
2011	-679327	312490	-366837	0	0	-366837	-372746	-16049	-3702	-909
2012	-726592	334232	-392360	0	0	-392360	-398624	-15603	-3442	-810
2013	-777147	357487	-419660	0	0	-419660	-426300	-15170	-3201	-722
2014	-831224	382362	-448862	0	0	-448862	-455900	-14748	-2977	-643
2015	-889066	408970	-480096	0	0	-480096	-4855761	-10462	-2020	-418
TOTALS	-11852524	5452145	-6400380	0	0	-6400380	-6400382	-675068	-296124	-150455

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANT
100% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-22947	-22947	0	0	0	0	0	0
1986	0	0	-1377	-1377	-133170	-6718	0	0	0	-139888
1987	0	0	-1459	-1459	-142492	-7121	0	0	0	-149613
1988	0	0	-1547	-1547	-152466	-7548	0	0	0	-160015
1989	0	0	-1640	-1640	-163139	-8001	0	0	0	-171140
1990	0	0	-1738	-1738	-174559	-8481	0	0	0	-183040
1991	0	0	-1842	-1842	-186778	-8990	0	0	0	-195768
1992	0	0	-1953	-1953	-199852	-9530	0	0	0	-209382
1993	0	0	-2070	-2070	-213842	-10101	0	0	0	-223943
1994	0	0	-2194	-2194	-228811	-10707	0	0	0	-239518
1995	0	0	-2326	-2326	-244828	-11350	0	0	0	-256178
1996	0	0	-2466	-2466	-261966	-12031	0	0	0	-273996
1997	0	0	-2614	-2614	-280303	-12753	0	0	0	-293056
1998	0	0	-2770	-2770	-299924	-13518	0	0	0	-313442
1999	0	0	-2937	-2937	-320919	-14329	0	0	0	-335248
2000	0	0	-3113	-3113	-343383	-15189	0	0	0	-358572
2001	0	0	-3300	-3300	-367420	-16100	0	0	0	-383520
2002	0	0	-3498	-3498	-393140	-17066	0	0	0	-410206
2003	0	0	-3707	-3707	-420659	-18090	0	0	0	-438750
2004	0	0	-3930	-3930	-450106	-19175	0	0	0	-469281
2005	0	0	-4166	-4166	-481613	-20326	0	0	0	-501939
2006	0	0	-4416	-4416	-515326	-21546	0	0	0	-536871
2007	0	0	-4681	-4681	-551399	-22838	0	0	0	-574237
2008	0	0	-4961	-4961	-589997	-24209	0	0	0	-614205
2009	0	0	-5259	-5259	-631296	-25661	0	0	0	-656958
2010	0	0	-5575	-5575	-675487	-27201	0	0	0	-702688
2011	0	0	-5909	-5909	-722771	-28833	0	0	0	-751604
2012	0	0	-6264	-6264	-773365	-30563	0	0	0	-803928
2013	0	0	-6640	-6640	-827501	-32397	0	0	0	-859897
2014	0	0	-7038	-7038	-885426	-34340	0	0	0	-919766
2015	0	0	124335	124335	-947406	-36401	0	0	0	-983807
TOTALS	0	0	0	-2	-12579345	-531113	0	0	0	-13110458

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANT
100% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1974	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-22947	-11775	-2627	-6404
1986	-139888	64348	-75540	0	0	-75540	-76917	-35882	-25144	-17882
1987	-149613	68821	-80792	0	0	-80792	-82251	-34882	-23321	-15941
1988	-160015	73606	-86409	0	0	-86409	-87956	-33911	-21741	-14205
1989	-171140	78724	-92416	0	0	-92416	-94056	-32966	-20217	-12659
1990	-183040	84198	-98842	0	0	-98842	-100580	-32048	-18749	-11281
1991	-195768	90053	-105715	0	0	-105715	-107557	-31155	-17421	-10053
1992	-209382	96315	-113067	0	0	-113067	-115020	-30288	-16256	-8959
1993	-223943	103013	-120930	0	0	-120930	-123000	-29445	-15116	-7983
1994	-239518	110178	-129340	0	0	-129340	-131534	-28626	-14056	-7114
1995	-256178	117841	-138337	0	0	-138337	-140663	-27829	-13071	-6340
1996	-273996	126038	-147958	0	0	-147958	-150424	-27055	-12155	-5650
1997	-293056	134805	-158251	0	0	-158251	-160865	-26303	-11303	-5035
1998	-313442	144183	-169259	0	0	-169259	-172029	-25571	-10511	-4487
1999	-335248	154214	-181034	0	0	-181034	-183971	-24860	-9775	-3999
2000	-358572	164943	-193629	0	0	-193629	-196742	-24169	-9090	-3564
2001	-383520	176419	-207101	0	0	-207101	-210401	-23497	-8453	-3176
2002	-410206	188694	-221512	0	0	-221512	-225010	-22844	-7861	-2830
2003	-438750	201824	-236926	0	0	-236926	-240633	-22209	-7310	-2522
2004	-469281	215869	-253412	0	0	-253412	-257342	-21592	-6798	-2248
2005	-501939	230891	-271048	0	0	-271048	-275214	-20993	-6322	-2003
2006	-536871	246960	-289911	0	0	-289911	-294327	-20410	-5879	-1785
2007	-574237	264149	-310088	0	0	-310088	-314769	-19843	-5467	-1591
2008	-614205	282534	-331671	0	0	-331671	-336632	-19292	-5024	-1418
2009	-656958	302200	-354758	0	0	-354758	-360017	-18756	-4728	-1264
2010	-702688	323236	-379452	0	0	-379452	-385027	-18236	-4397	-1126
2011	-751604	345737	-405867	0	0	-405867	-411776	-17730	-4089	-1004
2012	-803928	369806	-434122	0	0	-434122	-440386	-17238	-3803	-895
2013	-859897	395552	-464345	0	0	-464345	-470985	-16760	-3537	-797
2014	-919766	423092	-496674	0	0	-496674	-503712	-16295	-3289	-711
2015	-983807	452551	-531256	0	0	-531256	-540921	-11967	-2310	-478
TOTALS	-13110458	6030794	-7079662	0	0	-7079662	-7079664	-744412	-326035	-165398

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

PAGE 1 OF 2

PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANTS
150% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME DEPRECIATION	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-22947	-22947	0	0	0	0	0	0
1986	0	0	-1377	-1377	-199755	-6718	0	0	0	-206473
1987	0	0	-1459	-1459	-213738	-7121	0	0	0	-220859
1988	0	0	-1547	-1547	-228700	-7548	0	0	0	-236248
1989	0	0	-1640	-1640	-244708	-8001	0	0	0	-252710
1990	0	0	-1738	-1738	-261838	-8481	0	0	0	-270319
1991	0	0	-1842	-1842	-280167	-8990	0	0	0	-289157
1992	0	0	-1953	-1953	-299778	-9530	0	0	0	-309308
1993	0	0	-2070	-2070	-320763	-10101	0	0	0	-330864
1994	0	0	-2194	-2194	-343216	-10707	0	0	0	-353924
1995	0	0	-2326	-2326	-367241	-11350	0	0	0	-378591
1996	0	0	-2466	-2466	-392948	-12031	0	0	0	-404979
1997	0	0	-2614	-2614	-420455	-12753	0	0	0	-433208
1998	0	0	-2770	-2770	-449887	-13518	0	0	0	-463405
1999	0	0	-2937	-2937	-481379	-14329	0	0	0	-495708
2000	0	0	-3113	-3113	-515075	-15189	0	0	0	-530264
2001	0	0	-3300	-3300	-551130	-16100	0	0	0	-567230
2002	0	0	-3498	-3498	-589710	-17066	0	0	0	-606776
2003	0	0	-3707	-3707	-630989	-18090	0	0	0	-649079
2004	0	0	-3930	-3930	-675158	-19175	0	0	0	-694334
2005	0	0	-4166	-4166	-722420	-20326	0	0	0	-742746
2006	0	0	-4416	-4416	-772969	-21546	0	0	0	-794534
2007	0	0	-4681	-4681	-827098	-22838	0	0	0	-849936
2008	0	0	-4961	-4961	-884995	-24209	0	0	0	-909204
2009	0	0	-5259	-5259	-946945	-25661	0	0	0	-972606
2010	0	0	-5575	-5575	-1013231	-27201	0	0	0	-1040432
2011	0	0	-5909	-5909	-1084157	-28833	0	0	0	-1112990
2012	0	0	-6264	-6264	-1160048	-30563	0	0	0	-1190611
2013	0	0	-6640	-6640	-1241251	-32397	0	0	0	-1273648
2014	0	0	-7038	-7038	-1328139	-34340	0	0	0	-1362479
2015	0	0	124335	124335	-1421109	-36401	0	0	0	-1457509
TOTALS	0	0	0	-2	-18869017	-531113	0	0	0	-19400130

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANTS
150% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 F40)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON=CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR0,10)	(19) PRESENT WORTH=NCF (DR0,15)	(20) PRESENT WORTH=NCF (DR0,20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-22947	-11775	-8627	-6404
1986	-206473	94977	-111496	0	0	-111496	-112873	-52658	-36898	-26251
1987	-220859	101595	-119264	0	0	-119264	-120723	-51198	-34317	-23397
1988	-236248	108674	-127574	0	0	-127574	-129121	-49782	-31917	-20854
1989	-252710	116246	-136464	0	0	-136464	-138104	-48405	-29685	-18587
1990	-270319	124346	-145973	0	0	-145973	-147711	-47065	-27608	-16567
1991	-289157	133012	-156145	0	0	-156145	-157987	-45763	-25677	-14766
1992	-309308	142281	-167027	0	0	-167027	-168980	-44498	-23882	-13161
1993	-330864	152197	-178667	0	0	-178667	-180737	-43267	-22212	-11731
1994	-353924	162804	-191120	0	0	-191120	-193314	-42071	-20658	-10456
1995	-378591	174152	-204439	0	0	-204439	-206765	-40907	-19214	-9320
1996	-404979	186290	-218689	0	0	-218689	-221155	-39777	-17870	-8307
1997	-433208	199275	-233933	0	0	-233933	-236547	-38677	-16621	-7404
1998	-463405	213166	-250239	0	0	-250239	-253009	-37608	-15459	-6600
1999	-495708	228025	-267683	0	0	-267683	-270620	-36569	-14378	-5882
2000	-530264	243921	-286343	0	0	-286343	-289456	-35559	-13373	-5243
2001	-567230	260926	-306304	0	0	-306304	-309604	-34576	-12438	-4673
2002	-606776	279116	-327660	0	0	-327660	-331158	-33621	-11569	-4166
2003	-649079	298576	-350503	0	0	-350503	-354210	-32692	-10760	-3713
2004	-694334	319393	-374941	0	0	-374941	-378871	-31789	-10008	-3310
2005	-742746	341662	-401084	0	0	-401084	-405250	-30912	-9309	-2950
2006	-794534	365485	-429049	0	0	-429049	-433465	-30058	-8658	-2630
2007	-849936	390970	-458966	0	0	-458966	-463647	-29228	-8053	-2344
2008	-909204	418233	-490971	0	0	-490971	-495932	-28421	-7490	-2089
2009	-972606	447398	-525208	0	0	-525208	-530467	-27637	-6967	-1862
2010	-1040432	478598	-561834	0	0	-561834	-567409	-26874	-6480	-1660
2011	-1112990	511975	-601015	0	0	-601015	-606924	-26132	-6027	-1480
2012	-1190611	547680	-642931	0	0	-642931	-649195	-25411	-5606	-1319
2013	-1273648	585878	-687770	0	0	-687770	-694410	-24710	-5214	-1176
2014	-1362479	626740	-735739	0	0	-735739	-742777	-24028	-4850	-1048
2015	-1457509	670454	-787055	0	0	-787055	-794720	-19490	-3763	-779
TOTALS	-19400130	8924045	-10476086	0	0	-10476086	-10476088	-1091144	-475972	-240111

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PROJECT COST ANALYSIS
BASED ON PRESENT NORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE : EXIST. PLANTS
200% FUEL COST

YEAR	(1) CAPITAL COST	(2) BACKUP EXPENSES (ER \$,000)	(3) WORKING CAPITAL-NET (ER \$,060)	(4) INVESTMENT CASH FLOW (1+2+3)	(5) FUEL EXPENSES (ER \$,070)	(6) OTHER OPER EXPENSES (ER \$,060)	(7) TAXES OTHER THAN INCOME	(8) TAX DEPRECIATION (NON-CASH)	(9) CREDIT FOR POWER (ER \$,000)	(10) TOTAL EXPS BEFORE TAX (5+6+7+8+9)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	-22947	-22947	0	0	0	0	0	0
1986	0	0	-1377	-1377	-266340	-6718	0	0	0	-273058
1987	0	0	-1459	-1459	-284984	-7121	0	0	0	-292105
1988	0	0	-1547	-1547	-304933	-7548	0	0	0	-312481
1989	0	0	-1640	-1640	-326278	-8001	0	0	0	-334279
1990	0	0	-1738	-1738	-349117	-8481	0	0	0	-357599
1991	0	0	-1842	-1842	-373556	-8990	0	0	0	-382546
1992	0	0	-1953	-1953	-399705	-9530	0	0	0	-409234
1993	0	0	-2070	-2070	-427684	-10101	0	0	0	-437785
1994	0	0	-2194	-2194	-457622	-10707	0	0	0	-468329
1995	0	0	-2326	-2326	-489655	-11350	0	0	0	-501005
1996	0	0	-2466	-2466	-523931	-12031	0	0	0	-535962
1997	0	0	-2614	-2614	-560606	-12753	0	0	0	-573359
1998	0	0	-2770	-2770	-599849	-13518	0	0	0	-613367
1999	0	0	-2937	-2937	-641838	-14329	0	0	0	-656167
2000	0	0	-3113	-3113	-686767	-15189	0	0	0	-701956
2001	0	0	-3300	-3300	-734841	-16100	0	0	0	-750941
2002	0	0	-3498	-3498	-786279	-17066	0	0	0	-803345
2003	0	0	-3707	-3707	-841319	-18090	0	0	0	-859409
2004	0	0	-3930	-3930	-900211	-19175	0	0	0	-919387
2005	0	0	-4166	-4166	-963226	-20326	0	0	0	-983552
2006	0	0	-4416	-4416	-1030652	-21546	0	0	0	-1052197
2007	0	0	-4681	-4681	-1102798	-22838	0	0	0	-1125636
2008	0	0	-4961	-4961	-1179993	-24209	0	0	0	-1204202
2009	0	0	-5259	-5259	-1262593	-25661	0	0	0	-1288254
2010	0	0	-5575	-5575	-1350974	-27201	0	0	0	-1378175
2011	0	0	-5909	-5909	-1445543	-28833	0	0	0	-1474375
2012	0	0	-6264	-6264	-1546731	-30563	0	0	0	-1577293
2013	0	0	-6640	-6640	-1655002	-32397	0	0	0	-1687398
2014	0	0	-7038	-7038	-1770852	-34340	0	0	0	-1805192
2015	0	0	124335	124335	-1894812	-36401	0	0	0	-1931212
TOTALS	0	0	0	-2	-25158690	-531113	0	0	0	-25689803

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PROJECT COST ANALYSIS
BASED ON PRESENT WORTH
OF ANNUAL CASH REQUIREMENTS

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PROJECT: ORANGE COGENERATION
CASE 1 EXIST. PLANTS
200% FUEL COST

YEAR	(11) TOTAL EXPS BEFORE TAX (10 FWD)	(12) INCOME TAXES (-.46*11)	(13) TOTAL EXPS AFTER TAX (11+12)	(14) TAX DEPRECIATION (NON-CASH)	(15) INVESTMENT TAX CREDIT (-.10*1)	(16) OPERATING CASH FLOW (13+14+15)	(17) NET CASH FLOW (4+16)	(18) PRESENT WORTH=NCF (DR=.10)	(19) PRESENT WORTH=NCF (DR=.15)	(20) PRESENT WORTH=NCF (DR=.20)
1979	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	-22947	-11775	-8627	-6404
1986	-273058	125606	-147452	0	0	-147452	-148829	-69430	-48652	-34613
1987	-292105	134368	-157737	0	0	-157737	-159196	-67515	-45253	-30853
1988	-312481	143741	-168740	0	0	-168740	-170287	-65653	-42092	-27502
1989	-334279	153768	-180511	0	0	-180511	-182151	-63843	-39192	-24515
1990	-357599	164495	-193104	0	0	-193104	-194842	-62083	-36417	-21853
1991	-382546	175971	-206575	0	0	-206575	-208417	-60371	-33874	-19479
1992	-409234	188247	-220987	0	0	-220987	-222940	-58707	-31508	-17364
1993	-437785	201381	-236404	0	0	-236404	-238474	-57089	-29307	-15478
1994	-468329	215431	-252898	0	0	-252898	-255092	-55515	-27260	-13797
1995	-501005	230462	-270543	0	0	-270543	-272869	-53986	-25357	-12299
1996	-535962	246542	-289420	0	0	-289420	-291886	-52498	-23586	-10964
1997	-573359	263745	-309614	0	0	-309614	-312228	-51052	-21939	-9773
1998	-613367	282148	-331219	0	0	-331219	-333989	-49645	-20407	-8712
1999	-656167	301836	-354331	0	0	-354331	-357268	-48278	-18982	-7766
2000	-701956	322899	-379057	0	0	-379057	-382170	-46948	-17656	-6923
2001	-750941	345432	-405509	0	0	-405509	-408809	-45655	-16424	-6171
2002	-803345	369538	-433807	0	0	-433807	-437305	-44398	-15277	-5501
2003	-859409	395328	-464081	0	0	-464081	-467788	-43175	-14210	-4904
2004	-919387	422917	-496470	0	0	-496470	-500400	-41986	-13218	-4371
2005	-983552	452433	-531119	0	0	-531119	-535285	-40830	-12295	-3897
2006	-1052197	484010	-568187	0	0	-568187	-572603	-39706	-11437	-3474
2007	-1125636	517792	-607844	0	0	-607844	-612525	-38613	-10639	-3096
2008	-1204202	553932	-650270	0	0	-650270	-655231	-37550	-9896	-2760
2009	-1288254	592596	-695658	0	0	-695658	-700917	-36517	-9205	-2461
2010	-1378175	633960	-744215	0	0	-744215	-749790	-35512	-8563	-2194
2011	-1474375	678212	-796163	0	0	-796163	-802072	-34535	-7963	-1955
2012	-1577293	725554	-851739	0	0	-851739	-858003	-33584	-7409	-1743
2013	-1687398	776203	-911195	0	0	-911195	-917835	-32660	-6892	-1554
2014	-1805192	830388	-974804	0	0	-974804	-981842	-31762	-6411	-1385
2015	-1931212	888357	-1042855	0	0	-1042855	-918520	-27012	-5215	-1080
TOTALS	-25689803	11817292	-13872508	0	0	-13872508	-13872510	-1437868	-625109	-314826

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