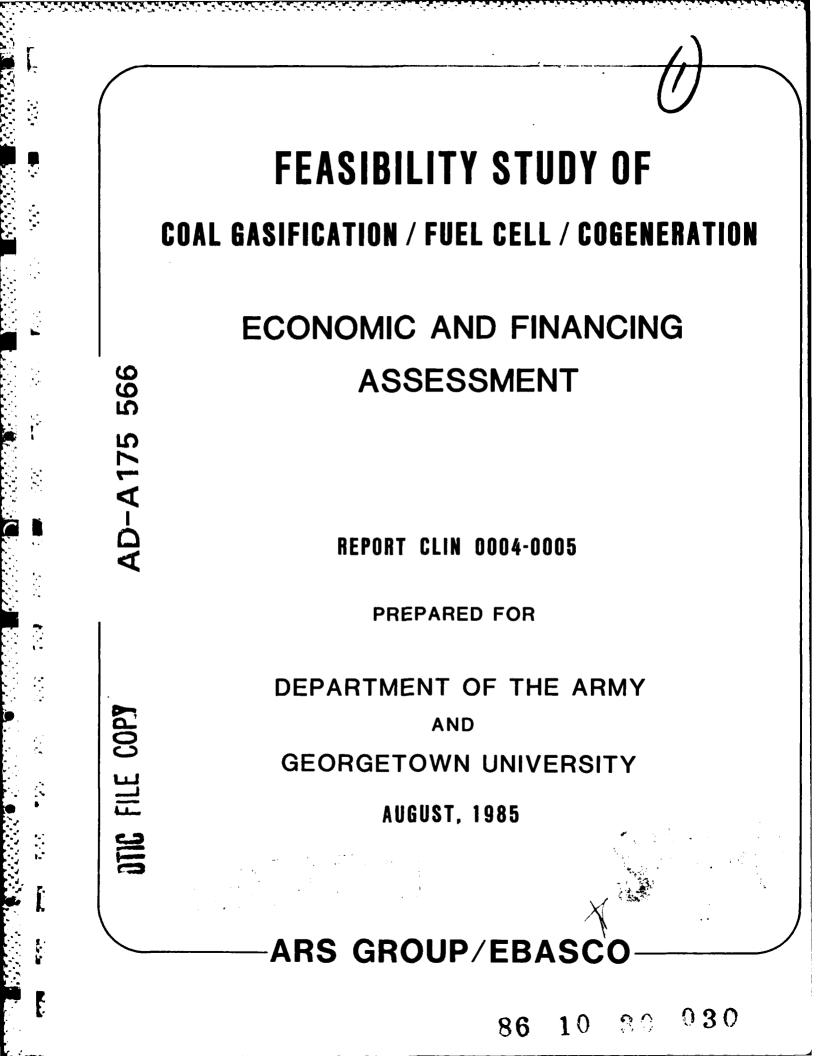


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FCONOMIC AND FINANCING
ASSESSMENT
REPORT CLIN 0004-0005
PREPARED FOR
DEPARTMENT OF THE ARMY
AND GEORGETOWN UNIVERSITY
AUGUST, 1985

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1.0 INTRODUCTION

1.1 <u>Purpose</u>

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-)The purpose of this report is to describe the economic and financing feasibility assessment carried out for a Coal Gasification/Fuel Cell/Cogeneration (GFC) Project for 4 specific sites: Scranton Army Ammunition Plant in Pennsylvania, Ft. Greely Army Base in Alaska, Ft. Hood Army Base in Texas, and Georgetown University in Washington, D.C.

Since their respective subjects are closely related and essential to the conclusions drawn for each site, the deliverables, CLIN 0004 (economics) and CLIN 0005 (financing) are combined into this one report.

The assessment presented in this document is part of an overall technical, economic, and financing feasibility study of power generation by a fuel cell using synthetic gas produced from coal. The concept involves selling the electric power and thermal output from the GFC plant to the site facility under a price structure that would produce significant energy-related cost savings for the site for the 20 years, 1990-2009.

Although, the government would partly fund this program, it is intended that the private sector will provide increasingly substantial capital investment and construct, own and operate a more efficient central coal energy facility. The feasibility study is the first stage of a program that links four key objectives to achieve commercialization of GFC technology to more broadly benefit the Army:

- A technology development cost objective that would reduce the prototype plant capital costs by 1/2 for second stage projects (early 90's) and by 2/3 for commercial stage projects (mid 1990's on).
- 2. A private ownership/financing objective that has private capital immediately involved in sharing the costs of the prototype plans, and solely involved when the technology is developed to the fully commercial stage. I.e., the initial investment by the

Department of Army would stimulate the inflow of private capital that would with commercialization of this technology, reduce or eliminate DOA capital expenditures.

- 3. Energy costs that would be equal to or less than the current energy costs of the Department of the Army.
- 4. Accelerated commercialization of an environmentally sound and efficient coal driven cogeneration technology.

Under this program, the government would fund the R&D-related capital costs of this emerging technology. This funding would cover 70 to 80% of prototype plant costs in the first stage and 50% of plant costs in the second stage. In the last stage, all funding would be from private sources.

The private GFC plant owner would share the savings resulting from the GFC plant energy output (compared to purchasing power from the utility and separating steam and hot water with existing boilers) and would be able to utilize the tax benefits (e.g., depreciation) available to any invester in industrial equipment.

1.2 Organization of Report

The site-specific economic feasibility results, the ownership/financing analysis, and the conclusions and recommendations of the study are presented in the four sections of this report as follows:

o Section 1.0 outlines the methodology of this report as well as the supporting work that precedes it. It also identifies the risks that are inherent in the economic analysis and the energy price scenarios used to determine ranges for sensitivity analysis. Finally, the conclusions of this analysis are summarized for each site. 寺に

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- Section 2.0 presents the economic feasibility results for each site, and are organized into the following subsections:
 - Costs benefits for the site
 - Basic economics of the GFC plant
 - Identification of incremental site requirements and capital costs
 - Site conclusions
- Section 3.0 presents the ownership/financing analysis (CLIN 0005) for the two sites found to be viable (Scranton AAP and Fort Greely) and has the following subsections:
 - Potential financing alternatives
 - Interested parties and likely site-specific arrangements
 - Ownership/financial results
- Section 4.0 presents the overall conclusions of the feasibility study and recommendations for further action (or not) for each site.

1.3 Methodology

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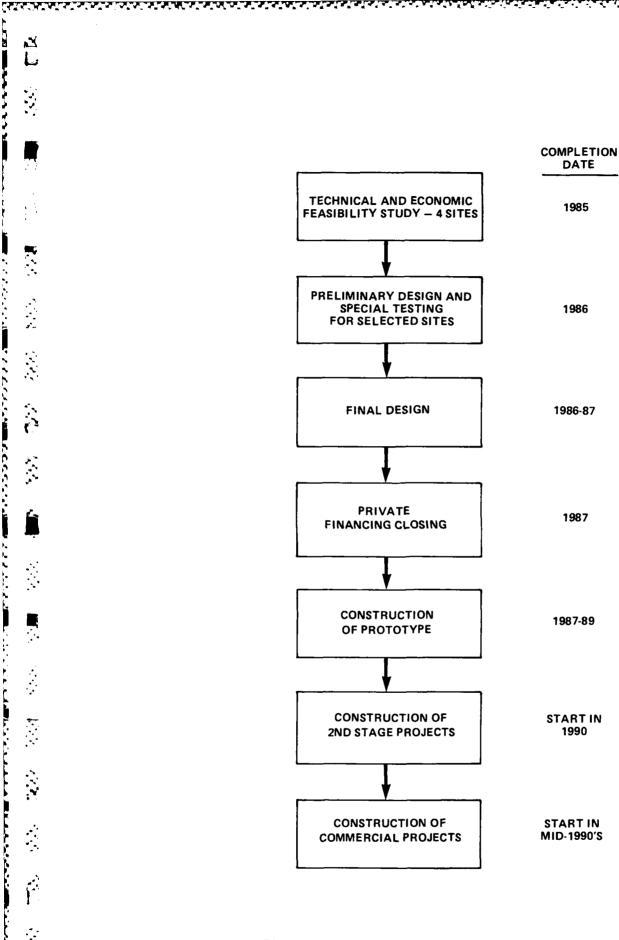
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It is the intent of this study to present results based on representative conditions rather than on technical designs, economics, and financing structures that are fully optimized. The key question is whether the concept could provide benefits to enough (not necessarily all) Army bases to warrant further R&D expenditures on preliminary system design and testing of selected coals and equipment. A subsequent decision would be made after the design and testing stage on whether to proceed into final design and to organize the private ownership and financing component of the concept. Figure 1-1 shows the development stages that would constitute such a program.



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FIGURE 1-1 GFC DEVELOPMENT SCHEDULE

Three steps in the feasibility work preceded this report.

- Development of a basic system description of the GFC plant, to be used as a point of departure for the feasibility configurations for each site. (CLIN 0001 report)
- 2. A preliminary survey for each of the four sites, documenting site-specific information to be addressed by the feasibility design and economic evaluation. (CLIN 0002 reports)
- 3. Development of GFC plant designs for each site (CLIN 0003 reports) to verify technical feasibility and to quantify GFC plant electric and thermal energy production for use in the economic analysis. Site specific incremental plant requirements are determined to provide a complete energy plant defined by site needs.

The analysis of basic economics was carried out in the followng major steps:

- a. Estimate capital costs for the GFC plant design developed for each site, including separate costs for the site specific increments.
- b. Develop typical operating and maintenance (O&M) costs for the GFC plant.
- c. Document current site energy use and costs.
- d. Project site energy use and costs under a range of potential energy price scenarios.
- e. Assess GFC plant economics for each scenario.

For those sites with strong enough economics, analysis of a potential ownership/financing structure was then carried out.

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1.4 Bases and Risks

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A number of economic assumptions and GFC plant risk factors are common for all sites and are discussed below.

Major factors in the analysis of existing site future energy costs are as follows:

- <u>Fuel cost</u>. Since the early 1970s, fossil fuel prices have varied unpredictably, with several sharp increases during this period, followed by relatively flat trends, (see Figure 1-2) or even a decrease in prices.
- 2. <u>Electric power costs.</u> While somewhat more predictable than fossil fuel prices, electric power prices have also shown sharp changes over the past 15 years as a result of impacts from fossil fuel prices as well as sharp increases in rates when new, and often costly, utility power plants were incorporated into utility rates. (See Figure 1-2)
- 3. <u>Army base replacement costs</u>. On-site boilers, steam/hot water distribution systems, and electric power distribution lines must periodically be replaced or upgraded by the Army base.
- 4. <u>O&M costs</u>. The on-site boilers, distribution systems, and other energy-related equipment must be operated and maintained, with an attendant labor and material cost.

GFC plant risks fall into two areas: technical and economic. Technical risks that directly affect the economic analysis are:

o <u>System efficiency</u>. GFC designs for the four sites had system efficiencies ranging from 19.0% to 38.9%.*

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^{*}System efficiency is defined as the Btu value of the electric power, thermal, and other revenue-producing outputs divided by the Btu value of coal delivered to the plant (minus any coal fines or coal residuals resold).

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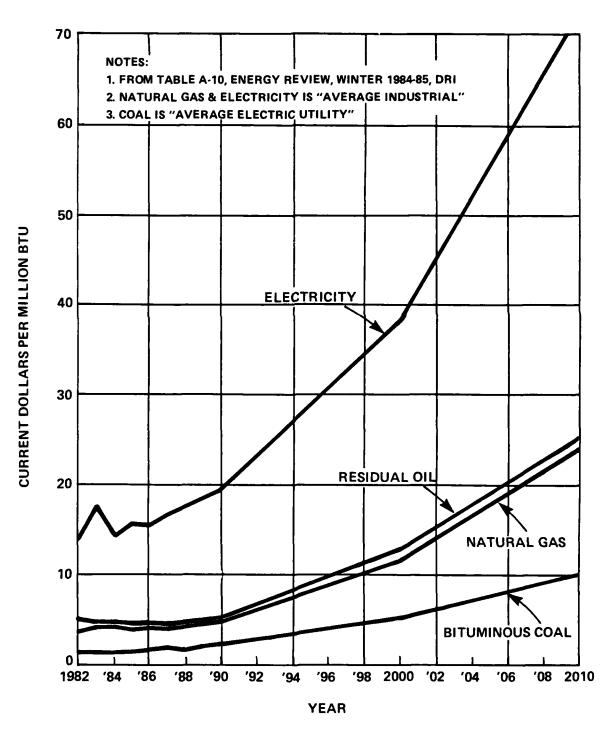


FIGURE 1-2 NATIONAL ENERGY PRICES

- o <u>System capacity factor</u>. The plant capacity factor is estimated at 81% for all GFC's but the GFC using the Westinghouse fuel cell at the Scranton, PA. site. Because of its use of anthracite coal, equipment to separate tars and oils from the raw gas was eliminated, raising this factor to 82%. See the CLIN 000303 report, para. 2.4 for details.
- o <u>GFC plant lifetime</u>. A minimum 20-year useful technical lifetime and a 10-year economic lifetime were assumed with a complete fuel cell reload every 5 years, starting in the 6th year of plant life.

The economic risks of the GFC plant relate to final plant capital costs, thermal user guarantees, O&M costs, electric power prices, and fossil fuel prices, as follows:

- o <u>Final capital costs</u>. The final GFC plant capital costs will be affected by final design and near-term inflation rates. However, the risk from higher capital costs is lower than energy price risks because capital costs become fixed by 1990, whereas the other risks continue throughout the lifetime of the plant. Moreover, the impact of higher capital costs is distributed over a number of years through depreciation and through the private debt financing structure.
- o <u>Thermal user guarantees</u>. For some cogeneration plants, the potential loss of the thermal demand (and attendant revenues) represents a significant risk. In this case, since the U.S. Government would be guaranteeing the steam purchase under long term contract (for a guarantee of maximum steam price), the risk is more limited. However, this risk is partially mitigated bythe ability of the thermal Management System to redirect unused thermal energy to the production of electric power.
- o <u>Plant O&M costs for GFC facility</u>. Plant O&M costs present two economic risks: the absolute amount of O&M costs as initially established, and the long-term escalation of these costs. The variation in the absolute amount of O&M costs initially

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established is not considered to be a great risk. For the plant design used (based on the ll megawatt UTC fuel cell module), a representative set of O&M costs were estimated, and deliberately made the same for all sites. Given the feasibility study accuracy range, regional labor costs and other variations in O&M fall within the accuracy provided in those estimates. The O&M costs as estimated for the first year of operation (1990) approximate \$2.5 million (exclusive of any insurance, taxes, and other annual costs). A breakdown of the O&M costs into major components is shown in Table 1-1.

Description of the second s

SCENARIO 1 -- Fossil Fuel Prices Remain Flat in Near-Term, Increase at Inflation Rate in Long-Term. The specific assumptions used for this scenario are a 0% escalation rate for 1985-1990 (less than the inflation rate) and a 5% escalation rate (equal to assumed inflation) for 1990-2009. Electric power, and O&M costs were assumed to escalate at inflation (5%) in the near-term and long-term. GFC electric and steam prices were assumed to escalate at 5% in the long-term. While fossil fuel prices have actually decreased in the last 1-2 years, for the 25 year time horizon, the projected energy costs under this scenario would likely be lower than actual. In any event, this scenario is representative of low fossil fuel escalation rate conditions.

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SCENARIO 2 -- Fossil Energy Prices Remain Flat in Near-Term, Escalate Significantly in Long-Term. The assumptions for this scenario were 0% escalation for fossil fuel prices for 1985-1990, and 10% for 1990-2009. Electric power costs were assumed to increase at 5% near-term and 10% long-term. GFC electric and steam prices were assumed to escalate at 10% in the long-term. O&M costs and inflation were assumed to escalate at 5% near-term and 8% long-term. (The inflation rate is affected by any long-term energy escalation rates, and therefore was assumed higher to be consistent with the overall scenario.)

This scenario is representative of a situation where energy prices remain flat under stable energy conditions in the near term, but reflect some unforeseen geopolitical event or economic conditions that produce a sustained high growth rate, starting in the early 1990s. While many analysts include such a scenario in their business and contingency planning, and this scenario could be judged to be a "middle", this scenario should just be considered representative of one set of possible conditions.

SCENARIO 3 -- Fossil Fuels Increase at Inflation Rate in Near-Term, Escalate Signifiantly in Long-Term. The specific assumptions under this scenario were a 5% excalation rate for fossil energy prices, electric power, O&M, and inflation for 1985-1990. For the term 1990-2009, a 10% escalation rate was assumed for fossil energy prices, purchsed electric power, and GFC plant electric power and steam prices, with an 8% escalation assumption for O&M costs and inflation.

The combined 25 year growth of energy prices under this scenario is significant. For the 25-year period, the projected energy costs likely are higher than would actually occur.

Exhibit 3 presents a summary of the key assumptions in the three scenarios used in the economic feasibility analysis.

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1.5 <u>Conclusions</u>

Based on analyses of the specific energy characteristics for each site and the three economic scenarios, the following conclusions were reached for each site:

- The Scranton AAP site was found to be viable, and showed a number of improvement opportunities that should be addressed in preliminary design and further economic analysis to improve the economics even further.
- THE FORT GREELY site was found to be viable, presenting not only strong cost savings but also providing an additional electric power capacity required by the electric utility system in that area.
- 3. THE FORT HOOD site was found not to be viable for any reasonable level of Army base energy cost savings, mainly due to the relatively low expected cost of future electric power in that area.
- 4. THE GEORGETOWN UNIVERSITY site was found not to be viable, due to projected electric power prices insufficient to provide suitable GFC plant operating margins, and special site constraints requiring significant increases in the plant capital costs.

ESTIMATED O&M COSTS (\$ Million)

Item	1985 <u>Dollars</u>	1990 Dollars *	1995 <u>Dollars*</u>
Labor and Fringes	1.0		
Contract Maintenance	0.2		
Supplies and Parts	0.5		
Site Utilities, Ash/Sludge	0.3		
Disposal and Miscellaneous			
Subtotal Annual Fuel Cell Reload Costs**	2.0	2.6	3.3 0.6**
Insurance and Taxes	0.2	<u>.2</u>	.3
TOTAL	2.2	2.8	4.2

* O&M escalated at 5 percent per year in base scenario.

** Start in 6th year of GFC plant operation.

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TABLE 1-2

ENERGY PRICE SCENARIOS

			<u>Scenario l*</u>		<u>Scenario 2**</u>		<u>Scenario 3***</u>	
			1985-	1990-	1985-	1990-	1985-	1990-
	Has Imp	act on	1990	2009	1990	2009	1990	2009
		GFC	Escal	Escal	Escal	Escal	Escal	Escal
	<u>Site</u>	Plant	Rate	Rate	Rate	Rate	Rate	Rate
Fuel Oil Price	x		0	5	0	10	5	10
Natural Gas Price	x		0	5	0	10	5	10
Coal Price	x	x	0	5	0	10	5	10
Purchased Electric Power from Utility	x		5	5	5	10	5	10
O&M Cost	x	x	5	5	5	8	5	8
Inflation Rate	x	x	5	5	5	8	5	8
GFC Plant Electric Power Cost	x	x	NA	5	NA	10	NA	10
GFC Plant Steam Cost	x	x	NA	5	NA	10	NA	10
Secondaria Def	initions							

Scenario Definitions:

- * Scenario 1 Flat near-term fossil fuel prices. Inflation rate increases in long-term.
- ** Scenario 2 Flat near-term fossil fuel prices. High and sustained longterm escalation rates.

*** Scenario 3 - Inflation increases in near-term fossil fuel prices. High and sustained long-term escalation rates.

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2.0 ECONOMIC ANALYSIS

2.1 General

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2.1.1 Capital Costs

Order of magnitude capital cost estimates in 1985 dollars are shown in Table 2-1. Each system and facility cost estimate is based on the equipment lists and other information found in Site Specific Project Descriptions, CLIN 000301, 2, 3 and 4, on information from equipment suppliers and on Ebasco Estimating Department records.

Items 1 through 12 in Table 2.1-1 include the following:

- a. Cost of equipment with insurance, freight to site and vendor engineering.
- b. Cost of direct labor based on craft union agreements, payroll taxes, insurance, fringes and supervision.

For the Washington DC, Pennsylvania and Texas sites, five eight hour shifts with casual overtime are assumed.

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TABLE 2.1-1

	C IN	APITAL COS	CAPITAL COST ESTIMATES ⁽¹⁾ (<u>IN THOUSANDS OF DOLLARS</u>)				
	Item	Scranton, PA W UTC	UTC	Fort Gre	Fort Greely, AK W UTC	Fort Hood, TX UTC	Washington, DC UTC
Γ.	UFL ${f Plant}$ Buildings and Site Development $^{(2)}$	3,400	3,900	10,300 12,700	12,700	3,500	14,300
, v	Coal Handling & Storage	1,600 1,700	1,700	3,000	3,000 3,900	1,700	1,700
З.	coal Lasification	5,200 3,600	3,600	4,900	4,900 6,400	5,000	3,600
4.	Gas Cooling, Cleaning and Compression	1,100	1,400	1,800	1,900	1,400	1,400
ۍ.	t u Shift	500	600	700	800	600	600
ò.	Sulfur Removal & Recovery	4,400	5,600	6,100	7,500	5,400	5,600
7.	Process Londensate Treatment	1,700	1,700	2,300	2,300 2,400	1,660	1,700
8.	Fuel Cells & Power Conditioning ⁽³⁾	15,400 15,400	15,400	18,400 18,400	18,400	15,400	15,400
۰	Thermal Management	2,600	1,900	4,500	4,200	2,400	1,900
10.	lu. Looling Mater	700	900	2,100	2,700	8 0Ó	006
11.	Mater Treatment	300	400	400	500	400	400
12.	12. Balance of Plant	1,500	2,000	2,800	2,800	1,500	2,000
13.	ufc Plant	38,400 3	39,100	57,300	64,200	39,700	49,500
14.	Preproduction Costs	880	940	1,410	1,740	1,000	940
15.	Inventory Capital	140	280	230	420	270	280
16.	16. Initial Catalysts & Chemicals	160	720	270	350	450	720

Total Plant Investment⁽⁴⁾

17.

Notes: I. Referenced to mid-1985 dollars; excludes interest during construction. 2. Includes civil work, buildings, building services (HVAC, Electrical, Lighting, Plumbing & Urainage). 3. Costs are based on system being a follow on to the manufacturer's prototype program (semi-production units). 4. Excludes accounts receivable and cash on hand for operating expenses.

51,440

41,420

59,210 66,710

39,580 41,040

For the Alaska site, six ten hour shifts with scheduled overtime are assumed.

c. Indirect construction costs, including temporary construction plant and facilities, nonmanual local hires and subcontractor profit and overhead.

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At Fort Greely the cost of incentives to attract and hold craft labor are included. This covers travel allowances, a construction camp and other living accommodations, recreational facilities, food subsidies, etc.

- d. Cost of engineering and home office overhead valued at 10% of capital costs.
- e. Project contingency which allows for uncertainties in the cost estimate that would be resolved in a detailed design. This contingency which varies with pricing sources and workscope delineation is assigned as follows:

Washington DC - 13% Scranton, Pa - 11% Ft Hood, Tx - 12% Ft Greely, Al - 14%

- f. Process contingency of 5.0% which allows for uncertainties in technical performance.
- q. An engineering and home office fee of 8% of process capital.

h. Project management

Other costs associated with the initiation of plant operation are as follows:

a. Preproduction cost (Item 14) covers the training of operating personnel, preoperational testing of equipment, extra

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maintenance and inefficient use of fuel and materials during startup. To approximate these costs, the following items were summed for each GFC plant:

1) one month's fixed and variable operating and maintenance costs.

- 2) 25% of one month's coal costs.
- 3) 2% of the plant investment (excluding fixed civil work).
- b. Inventory capital (Item 15) is estimated as:
 - 1) one month coal supply based on operation at rated capacity.
 - 2) one month supply of other consumables.
- c. Initial catalysts and chemicals (Item 16) are those contained in the process equipment but not in storage.

2.1.2 Operating and Maintenance Costs

As indicated in Section 1.3, typical operating and maintenance costs were estimated for the GFC facility and included the following components:

- o Labor and fringes
- o Contract maintenance
- o Supplies and Parts
- o Site Utilities and Waste Disposal
- o Fuel Cell Reloads
- o Insurance and Taxes

Labor and Fringes - Labor costs were based on the level of staffing outlined in Section 2.5 of CLIN 0003 and an average wage rate of \$15 per hour. Fringe benefits were estimated at 10 percent base salary.

<u>Contract Maintenance</u> - Outside maintenance assistance during outages and for specialized tasks was estimated as 25 percent of total maintenance costs. In-house maintenance labor included in "Labor and Fringes" above, was estimated at 15 percent of total maintenance costs for a total maintenance labor component of 40 percent.

<u>Supplies and Parts</u> - Expenses for maintenance materials, tools and spare parts was estimated at 60 percent total maintenance costs. (Total maintenance costs were estimated at an average rate of 2 percent of investment cost).

<u>Site Utilities and Waste Disposal</u> - Expenses were based on estimated quantities presented in CLIN 0003 and the following unit cost factors obtained at the Georgetown site:

0	Water	-	\$.698/100 cF
0	Sewage	-	\$1.297/100 cF
0	Electricity	-	5.4¢/kWh
0	Ash/Sludge	-	\$10/ton
0	Natural Gas (option)	-	\$4.80/10 ⁶ BTU
0	Catalysts/Chemicals	-	\$175,000/yr

<u>Annual Fuel Cell Reload Costs</u> - Replacement of the fuel cell stack every five years, or 20% annually every year was estimated at \$32/kW-yr.

<u>Insurance and Taxes</u> - Insurance and taxes were estimated at \$200,000/yr or about 1/2 percent of total investment cost.

2.1.3 Natural Gas Standby

A natural gas standby system was considered at all sites but Alaska, as a means for providing a secure source of anode gas for the fuel cell during a major failure in the coal handling, gasification or gas processing systems. Not having an available source of natural gas, this system was not considered for Fort Greely. ļ

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The capital cost of a standby system which includes the gas service connection, a methane reformer, hydrodesulfurizer and gas compressor is estimated by Westinghouse to be \$4,700,000. An equivalent system for the larger UTC system is estimated to be \$6,600,000.

With the plant capacity factor of 81% estimated for this project, avoided costs would have to be above 20%/kwh to pay for the annual equivalent capital cost and associated fixed charges of the natural gas standby system. For this reason and also noting that all sites can maintain flow of heating steam during a GFC system outage by means of their existing heating plants, the option for a natural gas standby system was rejected.

2.1.4 <u>Site Specific Increments</u>

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Site specific increments have been defined and described in the CLIN 0003 report series. These increments represent additional capital costs that are not considered a part of the GFC system or its economics but that are nevertheless, a supplement that is required or that has been requested to satisfy other related site requirements.

A brief description of these increments and their costs are as follows:

Scranton, AAP, Pennsylvania

This increment consists primarily of the acquisition of land and the steam and condensate connections to the existing AAP mains.

Capital Cost - \$400,000

It is proposed that the land for the GFC would be purchased from the Scranton City Corporation by the third party owner and given to the Department of the Army.

Fort Greely, Alaska

The major part of this increment is for the purpose of allowing the use of coal to meet all Main Post energy requirements.

The increment consists of additional gasifiers, pressure blowers, an aboveground insulated raw gas pipeline to existing boiler, reworking of an existing boiler to burn the low Btu gas, additional coal handling and storage and the steam and condensate connections (because of unusual length) between the GFC and the existing steam header.

The incremental capital costs imposed by severe cold (e.g., foundation work, space heating and the greater amount of enclosure required) have also been assigned to this category.

Capital Cost, Westinghouse System - \$17,500,000 Capital Cost, UTC System - \$20,000,000

Fort Hood, Texas

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This increment consists of a complete steam absorption unit chilled water plant, a high temperature hot water plant and an extensive underground chilled and hot water piping distribution system with tie-ins and heat exchangers at each building served.

Capital Cost - \$17,500,000

Washington, D.C.

Included in this increment are relocation of disrupted facilities, replacement of parking and relocation of athletic playing surface.

Capital Cost - 16 to \$20,000,000

2.2 Scranton, Pennsylvania Site

The Scranton Army Ammunition Plant (AAP) site was described in previous reports (CLIN 000202 and CLIN 000302). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this section contains the following:

- 1. Site costs/benefits.
- 2. Economics.

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3. Conclusions.

Although the "base system" for this site is designed around the Westinghouse fuel cell, it was found that the total system as conceived in CLIN 000302, which includes the use of anthracite coal, resulted in a negative return on investment. (It is believed that with further optimizing and use of another coal type, economics of the Westinghouse based GFC will improve.) By replacing this system with one based on the UTC fuel cell similar to that described for the Washington D.C. site (CLIN 000301) and supplied with an eastern bituminous in lieu of the anthracite coal, the return on investment increased to 11.1%.

For this reason economics of the UTC cell system rather than of the Westinghouse system is analyzed in this section.

2.2.1 Site Costs/Benefits

The benefits to Scranton AAP can occur through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.2.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analyis of GFC benefits to the site, 25-year projections were made of energy use and costs without the

GFC for the years 1990-2009. The cost factors projected are discussed as follows:

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<u>Electric Energy</u>. Currently, Scranton AAP consumes about 30 million kWhs per year of electric energy. The escalation in kWh use is expected to be moderate. 2% per year was assumed in the near-term, providing somewhat more than 32 million kWh in 1990. A 2% escalation rate was assumed for the long-term as well.

The current electric energy (kWh) rate is 4.3 e/kWh. A 5% annual escalation rate was assumed for all scenarios in the near-term (1985-1990), providing a rate of approximately 5.5 e/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for a summary of assumptions made for each scenario.)

The current annual electric energy cost is about \$1.3 million. Under the above assumptions, it would increase to \$1.8 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

<u>Electric Demand</u>. Currently, Scranton AAP has a peak electric demand of about 8.5 MW. It was assumed this would increase at a moderate rate of 2% per year, both in the near-term and long-term.

The current demand charge is approximately \$3.5/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of \$4.4/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about \$360,000 annually. Under the assumptions used above, this would increase to \$500,000 by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

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The total electric power costs, then, are currently \$1.6 million, likely to increase to \$2.3 million by 1990.

<u>Natural Gas</u>. Currently, about 350 million cubic feet of natural gas are consumed annually by Scranton AAP. Assuming this usage increases by 2% per year, an assumption consistent with the total energy use projections made for the site, the natural gas required would increase to over 380 million cubic feet by 1990, with a long-term escalation of 2% per year.

The current cost of natural gas is about \$5.80 per mcf (58¢ per therm). Under the first (base) scenario, this price would stay flat through 1990, then increase in the long-term at 5% per year. While near-term decreases in natural gas (and oil) costs could occur, given the current softness of the those prices, the first scenario provides a low level of natural gas prices from 1990 to 2009.

The current annual gas cost of \$2 million would increase to about \$2.2 million by 1990 under the base scenario assumption.

Other Fossil Fuels. Scranton AAP uses a minor amount of fuel oil with usage assumed to increase at 2% per year, both in the near-term and long-term. Its current price of 63¢ per gallon was assumed to stay flat under the first scenario analysis, and increase at 5% per year thereafter. The total annual cost of the fuel oil use is negligible (perhaps \$10,000) compared to the natural gas cost.

Operating and Maintenance Costs. Incomplete information was available on the amount of energy-related O&M costs for Scranton AAP. Based on on available data, a current O&M cost of slightly more than \$500,000 per year was assumed. This was assumed to increase 5% annually (inflation) to \$670,000 per year by 1990, and under the first scenario, to increase by 5% per year thereafter.

<u>Total Site Energy Costs</u>. The total annual energy-related costs for Scranton AAP are currently over \$4.2 million. Under the first scenario, these costs would increase to \$5.2 million in 1990, and would increase to \$9-\$10 million per year in 1999. The total cost for the ten years, 1990-2009, would approximate \$70 million.

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Г 22 Table 2.2-1 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.2.1.2 Costs/Benefits With the GFC

The cost savings to Scranton AAP can occur through one or more of the following: electric energy savings, electric demand savings, reduced use of gas in their existing boilers, and O&M. The electric power savings would occur if the GFC plant sells power to the site at a cost lower than the purchase price of power from the electric utility.

The site (AAP) fuel savings would occur if the GFC plant sold steam to the AAP at a price lower than it would otherwise cost the AAP to produce it in their gas fired boilers.

The site would have O&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Scranton AAP were primarily the result of the difference in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing gas fired boilers.

TABLE 2.2-1

SITE ENERGY USE, PRICE AND COST PROJECTIONS Scenario 1 (Base) Scranton AAP, Pennsylvania

Energy Parameter	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	1989	<u>1990</u>	1990-2009 Escalation Rate
Electric Power								
Energy (Mil kWh) Rate (¢/kWh)	28.9 4.1	29.5 4.3	30.1 4.5	30.7 4.8	31.3 5.0	31.9 5.3	32.6 5.5	2% 5%
Demand (MW) Rate (\$/kW/Mo) Overall Rate (¢/kWh)	8.4 3.3 5.3	3.5	3.6	8.9 3.8 6.1	4.0		4.4	2% 5%
Fuels								
Natural Gas (Mil Mcf) Price (\$/Mcf)		348 5.8	355 5.8	362 5.8	369 5.8	376 5.8	384 5.8	2% 5%
Fuel Oil (Mil gal) Price (\$/Gal)	Small : .60	Small : .63	Small 3 .63	Small 9 .63		Small : .63	Small .63	2% 5%
O&M Cost (\$ Mil)	0.5	0.5	0.5	0.6	0.6	0.6	0.7	5%
Total Energy-Related Costs (\$ Million)	3.9	4.2	4.4	4.6	4.8	5.0	5.2	

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There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. This was the case for the Scranton AAP site feasibility analysis. Pennsylvania Power and Light (PP&L) has an "avoided cost" rate structure (see para. 2.2.2.2) that exceeds the expected rate for purchased power by Scranton AAP which made it possible to correspondingly lower the steam price.

At an assumed 2% growth rate, the current consumption of 90 million pounds of steam per year would increase to approximately 100 million pounds per year by 1990. For the Scranton AAP GFC feasibility design, the GFC plant steam output is 66 million pounds per year (see CLIN 0003). The assumed GFC purchase price by Scranton AAP for this steam (in 1985 dollars) is \$4 per thousand pounds, a price set to provide reasonable savings through reduced use of the on-site boilers. At an assumed 5% annual escalation rate, this price would be \$5.10 per thousand pounds in 1990, the first year of GFC plant operation and under the base scenario, would also escalate at 5% in the long-term.

With the GFC, Scranton AAP's estimated \$2.2 million cost for purchased fuels in 1990 would be reduced to about \$2.0 million for purchased steam and remaining fuel requirements, and the 1990 D&M could be reduced from \$670,000 to \$370,000, or by \$300,000.

The total savings in 1990 under these assumptions is estimated at \$500,000-\$600,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over \$800,000 per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate \$7 million.

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These savings are conservative since they are based on the first scenario which predicts lower energy costs without the GFC than those forecast by most experts through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be \$8-\$11 million for the ten-year period. Table 2.2-2 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, on this tabulation, a GFC energy cost comparison is shown next. For 1990, the cost of the GFC thermal energy purchased, combined with the O&M savings that would likely occur is \$300,000, whereas the equivalent cost of fuel and O&M without the GFC is estimated at \$800,000. Finally, the exhibit shows the estimated GFC related cost savings for the second and third scenarios analyzed.

2.2.2 GFC Plant Economics

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The GFC plant economic attractiveness is measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the magnitude of investment and the cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

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In the calculation used, the yearly after-tax cash flows for 10 operating years are discounted to a present value and effectively divided by the present value of private capital investment which occurs over 3 years. A negative return occurs if the total amount of the operating cash flows is less than the total private investment. The ROI of an investment is that discount rate at which the present value of the operating cash flows exactly equals the present value of the private capital investment.

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TABLE 2.2-2

PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC (\$ Million)

Scranton AAP, Pennsylvania

	Current	Proje	cted	10-Yr Total
SCENARIO 1 (Base)*	1985	<u>1990</u>	1995	(1990-1999)
Total Site Energy Use				
Electric (million kWh)	29.5	32.6	35.9	356.4
Thermal (billion Btu)	97.3	107.5	118.6	1176
Total Energy Cost		-		
Cost without GFC		5.2	7.2	71.4
Cost with GFC		4.7	6.5	64.6
GFC Energy Cost Comparison				
Cost of Energy From GFC		.3	.5	4.4
Cost of Same Energy and O&M Without GFC		.8	1.2	11.2
Cost Savings with GFC		.5	.7	6.8
SCENARIO 2:** Cost Savings wi	ith GFC	.5	.8	8.2
SCENARIO 3:*** Cost Savings wi	ith GFC	.7	1.1	10.7

* Flat near term fossil fuel prices. 5% long-term escalation.

** Flat near term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

2.2.2.1 Capital Costs

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Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30% (See Table 2.1-1). Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be \$35.7 million and the private contribution \$15.3 million, as shown in Table 2.2-3. These shares are derived as follows:

The estimated GFC plant construction and preproduction costs (1985 dollars) are \$40.0 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of \$46.9 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital project to requirements for any begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendant construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Scranton AAP site for these items is \$2.3 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at \$1.8 million (fixed) for the project. These include:

- o Financing fees of \$1.2 million, or 8% of the private capital requirement.
- o Third party development fee of \$300,000, or 2% of the private capital.
- Legal and other expenses of \$300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Scranton project, then, are \$51.0 million. Table 2.2-3 shows the percentage and timing breakdown of these requirements for the private and governmental portions of \$15.3 and \$35.7 million respectively.

2.2.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the Scranton AAP site, the GFC plant outputs are electric power and steam. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year and the price received for the power sold. In this case, the entire electric power output is assumed sold to the electric utility, Pennsylvania Power & Light (PP&L). The assumed avoided cost structure, as drawn from projections provided by the utility to the state Public Utilities Commission, is 8.8¢ per kilowatt hour through 1992. From then, and based on projections provided by PP&L, avoided costs escalate to 12.7¢/kWh in 1995. It then is escalated at either 5% or 10% per year, depending on the scenario analyzed.

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TABLE 2.2-3

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GFC PLANT CAPITAL REQUIREMENTS (\$ Million)

Scranton AAP, Pennsylvania

	1985 Dollars	Installed Costs Assuming <u>5-Percent Escalation Rat</u> I987 1988 1989 Tot					
Construction Costs				<u>=</u>			
GFC Plant Equipment	35.2						
GFC Plant Civil	3.9						
Preproduction Costs	.9						
Subtotal	40.1	9.0	18.5	19.4	46.9		
Other Costs							
Construction Interest				0*	0		
Working Capital				2.3	2.3		
Development, Financing, Legal and Other				1.8	<u>1.8</u>		
Subtotal					4.1		
Total Capital Requirements		9.0	18.5	23.5	51.0		
At a 30/70 Mix of Capital Contributions:							
Private Capital				15.3*	15.3		
Government Capital		9.0	18.5	8.2	35.7		

* Private capital would be legally committed at the beginning of construction, but would be contributed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

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The electric energy sold to PP&L is estimated at 88 million kilowatt hours per year in the first five years of operation, increasing to approximately 94 million kilowatt hours thereafter. The assumption behind this increase is that, with operating experience, the plant availability should increase after some period of operation.

The total electric revenues to the GFC plant corresponding to this output are \$7.8 million in 1990, increasing to \$12.0 million in 1995 in accordance with the increased kWh output and the increased rates. The ten-year revenues for the plant are estimated at \$106 million.

The remaining revenues for the plant are steam revenues. The annual amount of steam sold upon startup of the GFC plant is 9200 thousand pounds per hour and 35 million per year, increasing to 38 million pounds per year in 1995 and after. In accordance with the steam price assumptions discussed earlier, the expected annual revenues in 1990 are \$340,000, increasing to \$460,000 in 1995. The ten year stream of steam revenues is estimated at \$4.5 million.

Table 2.2-4 shows the key electric power and other output assumptions for the GFC plant for the first year and sixth year of operation, and cumulatively for the first ten years of operation.

Both the O&M and the fuel operationg costs are significant. The O&M cost assumptions were explained in Section 2.2.2. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is \$260,000, assumed to escalate at 5% per year long-term.

Using a coal price of \$58 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the Scranton GFC plant is estimated at \$3.0 million. With a 5% excalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is \$3.8 million.

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TABLE 2.2-4

GFC PLANT ECONOMIC OUTPUTS

Scranton AAP, Pennsylvania

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First Year (1990)	Sixth Year (1995)	First 10 Years Operation (1990-1999)
12.3	12.3	
7096	7596	
0	0	0
NA	NA	
87.3	93.4	904
8.8	12.7	
9200	9200	
66.1	70.7	684
5.10	6.50	
	Year (1990) 12.3 7096 0 NA 87.3 8.8 9200 66.1	Year (1990) Year (1995) 12.3 12.3 7096 7596 0 0 NA NA 87.3 93.4 8.8 12.7 9200 9200 66.1 70.7

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While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

o 10% investment tax credit.

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o 5-year straight line depreciation.

- o 50% combined federal and state marginal annual income tax rate.
- As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.2.2.3 Return on Investment

For the basic economic analysis (CLIN 0004 requirement), return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

^{*} With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce marginal annual income tax rate, a measure that would increase the ROI in the long-term.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and detailed economic/financing analysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- o The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not optimized in this feasibility study. The purpose of the next stage -preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operating costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughtly set at 30%, based on an expected production volume capital cost for the GFC plant at 30% of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

A feasibility ROI criterion of 10%, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored (see Section 6.0), it distorts the ROI such that general comparisons with other ROIs are harder to make. The 10% ROI criterion roughly translates into a 25% or higher

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return on equity (ROE), assuming a 2/l private debt/equity ratio. (Alternative financing structures and the ROE results are discussed in Chapter 6.0, Financing and Ownership Analysis.)

As shown in Table 2.2-5, the total GFC plant revenues for Scranton AAP in 1990 are estimated at \$8.1 million, and total costs at \$5.8 million, resulting in an operating cash flow of \$2.3 million. This operating margin increases steadily, with a 10-year total operating cash flow of approximately \$34 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a slight tax savings. Therefore, the net cash flow in 1990 is slightly greater than the operating cash flow. However, starting in 1995, a tax payment of 50% of the operating cash flow occurs.* Overall, the net cash flow is fairly steady at \$2.0-\$2.5 million during the first ten years of plant life, with a total 10-year cash flow of almost \$24 million.

The resulting ROI under the base scenario is approximately 11%. The results under Scenario 2 (flat near-term fossil prices and high, sustained long-term prices) is approximately 10%. Under Scenario 3, with a 5% annual increase in near-term fossil energy prices, and high. sustained long-term escalation rates, the net cash flow would decrease significantly during the first ten years of operation, resulting in a 10-year cash flow of 2/3 that of the first two scenarios and an ROI of about 3%. While this scenario does not appear as likely as either one of the first two, its effects should be evaluated in further financial/economic analysis.

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^{*} The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2.2-5

GFC PLANT CASH FLOW SUMMARY

Scranton APP, Pennsylvania

Economic Variable	1990	1995	10-Year Total (1990-1999)
Base Scenario (Flat near-term	fuel prices.	5%/year long	y-term)
Revenue			
Electric	7.8	12.0	106.0
Other Subtotal	<u>.3</u> 8.1	$\frac{.5}{12.5}$	<u>4.5</u> 110.5
Cost			
Fuel	3.0	3.8	37.6
O&M & Other Subtotal	2.8 5.8	<u>4.2</u> 8.0	<u>38.8</u> 76.4
Operating Cash Flow	2.3	4.4	34.1
Tax Saving (Playment)* Net cash flow	$\frac{.2}{2.5}$	$\frac{-2.2}{2.2}$	$\frac{-10.4}{23.7}$
ROI	11.1%		
<u>Scenario 2</u> (Flat near-term fu	uel prices.	10%/year long	term)
Net Cash Flow	2.5	1.8	22.5
ROI	9.7%		
<u>Scenario 3</u> (Fuel prices 5%/ye	ear near term	, 10%/year lon	g term)
Net Cash Flow	2.1	1.1	16.0
ROI	2.7%		

*Does not include the annual syngas tax credit.

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The analysis of the Scranton AAP site led to the following conclusions:

 Potential site thermal and O&M savings could be significant, approximating 10% of the project site energy costs, and providing a certainty in energy prices not available from other fuel suppliers and the electric utility.

- 2. The Westinghouse GFC plant as configured for this site for use with anthracite coal, did not provide acceptable economics because of lower economies of scale for the smaller plant and had a lower overall efficiency than the UTC configuration which used bituminous coal. (Accordingly, the analysis of this section was based on the UTC system.)
- 3. For a set of energy prices that provides the Scranton AAP a 10% cost savings, the minimum GFC plant after-tax return on total investment indicator exceeds 10% with the potential for improvement by optimization in final design.

2.3 Fort_Greely, Alaska Site

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The Fort Greely site was described in previous reports (CLIN 000204 and CLIN 000304). To verify the economic feasibility of the GFC plant, the cost and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this section contains the following:

- 1. Site costs/benefits.
- 2. Economics.
- 3. Conclusions.

Although the "base system" for Fort Greely was in CLIN 000304, designed around the Westinghouse fuel cell, it was found that this system resulted in a negative return on investment. (It is believed that with further optimizing, economics of the Westinghouse based GFC may improve.) By replacing this system with one based on the UTC fuel cell similar to that described for the Fort Hood, Texas site (CLIN000303) and supplied with an eastern bituminous in lieu of the anthracite coal, the return on investment increased to 11.1%.

For this reason economics of the UTC cell system rather than of the Westinghouse system is analyzed in this section.

2.3.1 Site Costs/Benefits

The benefits to Fort Greely can occur through savings in electric power use, fuel use, and operating and maintenance (0&M) costs.

2.3.1.1 Energy Use and Costs Without the GFC

As base of comparison for the analysis of GFC benefits to the site, one must first project the energy use and costs without the GFC plant. The objective of this 25-year projection was to derive reasonable energy use and cost numbers for the years 1990-2009. Therefore, while current and expected near-term energy use and prices were evaluated, there was no attempt to analyze temporary aberrations in electric power or fuel orices. Each of the energy cost factors as projected is discussed in the following paragraphs. <u>Electric Energy</u>. Currently, Fort Greely consumes about 15 million kWhs per year of electric energy. The expected near-term and long-term escalation in kWh use is almost zero.

The current electric energy rate is 6.8¢/kWh. While scenarios were evaluated with alternative energy price escalation rates, in the nearterm (1985-1990), a 5% annual escalation rate was assumed for all scenarios. This would provide a rate of approximately 8.7¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2).

The current annual electric energy cost is about \$1 million. Under the above assumptions, it would increase to \$1.4 million in 1990. The long-term projection of electric energy costs depends on escalation that vary between 5% and 10% per year.

<u>Electric Demand</u>. Currently, Fort Greely has a peak electric demand of about 3 MW, which is not expected to increase materially.

The current demand charges, based on a wheeling charge by Golden Valley Electric Association (GVEA), is approximately \$7/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of almost \$9/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about \$250,000 annually. Under the assumptions used above, this would increase to \$330,000 by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently \$1.6 million, likely to increase to \$1.7 million by 1990.

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<u>Fuel Oil</u>. Fort Greely uses about 2.3 million gallons of fuel oil per year as its only fossil fuel consumption (natural gas is not available). As with electric power, the thermal energy and related fuel requirements, are not expected to increase materially over time.

The current cost of No. 2 fuel oil is 95¢ per gallon, assumed flat through 1990 under the base scenario analysis, then increasing in the long-term at 5% per year.

The total annual fuel oil cost is currently about \$2.2 million, increasing marginally with time in accordance with the above assumptions.

Operating and Maintenance Costs. Fort Greely's energy plant-related O&M costs are currently about \$900,000 per year. These are expected to increase at an inflation rate, (5%) resulting in O&M of \$1.1 million in 1990. The long-term escalation rates for O&M were varied between 5-8% across the scenarios analyzed.

<u>Total Site Energy Costs</u>. The total annual energy-related costs for Fort Greely are currently \$4.3 million. Under the first scenario, these costs would increase to \$5 million in 1990. Under the base scenario analysis (5% per year energy price escalation long-term), the total energy related costs for the site would increase to \$8 million per year in 1999 and the total cost for the ten years, 1990-2009, would approximte \$6 million.

Table 2.3-1 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.3.1.2 Site Cost/Benefits With the GFC

The cost savings to Fort Greely can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility. The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

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IABLE 2.3-1 SITE ENERGY USE, FRICE AND COST FROJECTIONS - Scenario <u>1 (Ba</u>se)

Fort Greely, Alaska

tnergy Parameter	1984	<u>1985</u>	<u>1986</u>	1987	1988	1989	<u>1990</u>	1990-2009 Escalation Rate
Łlectric Power								
Eneryy (Mil kWhs) Rate (⊄/kWh)	15.7 6.5	15.7 6.8	15.8 7.2	15.8 7.5	15.8 7.9	15.9 8.3	15.9 8.7	0.2% 5%
Uemand (MW) Rate (\$/kW/Mo)	3 6.7	3 7.0	3 7.4	3 7.7	3 8.1	3 8.5	3 8.9	5. 23 23
Overall Rate (\$/Kwh)	8.0	8.5	8.8	9.3	9.7	10.2	10.8	
Fuels								
Natural Las (Mil Mcf) Price (\$/Mcf)	NA							
<pre>Fuel Oil (Mil gal) (Price (\$/[as))</pre>	2.3 .95	0.2% 5%						
U&M Cost (\$ Mil)	0.8	0.9	0.9	1.0	1.0	1.1	1.1	5%
Total Energy- Related Costs (\$ Million)	4.3	4.4	4.5	4.6	4.8	4.9	5.0	

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The site would have O&M savings if it did spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Fort Greely were primarily the result of the difference in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing oil fired boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on stream, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power Our analysis of GVEA capacity and energy costs for the site. requirements in the 1990s indicates that the value of GVEA of new capacity in the Fort Greely area should be substantial. However, we have not assumed it would exceed the projected purchase price of power by Fort Greely. Therefore, the GFC plant was assumed to provide all of the Fort Greely electric power, and then sell its excess to GVEA. The price for GFC power sold to Fort Greely was assumed equal to its purchased cost of power, and the site savings were provided through the sale of lower-cost steam and through savings in O&M.

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Fort Greely currently consumes about 230 million pounds of steam per year, expected to increase marginally over time. The expected GFC plant output, as configured for Fort Greely is 67 million pounds per year (see CLIN 3). The assumed purchase price for this steam (in 1985 dollars) is \$6 per thousand pounds, clearly less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be \$7.7 per thousand pounds in 1990, the first year of GFC plant operation. Under the base scenario, this price was assumed to escalate at 5% per year in the long-term. 122222222

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Fort Greely's expected \$2.2 million cost for purchased fuels in 1990 would be reduced to about \$1.9 million for purchase steam and remaining fuel requirements, and the 1990 O&M could be reduced from \$1.1 million to \$600,000, or \$500,000.

The total estimated site savings in 1990 under these assumptions is estimated at \$800,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over \$1.3 million per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate \$10.3 million.

These savings are likely to be the minimum that will be achieved. since the first scenario is likely to produce lower energy costs without the GFC plant than is expected through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be \$12-20 million for the ten-year period. Table 2.3-2 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, a GFC energy cost comparison is shown next on the exhibit. For 1990, the cost of the GFC electric and thermal energy purchased, is \$3.0 million, whereas the cost of these fuels and D&M costs without the GFC is estimated at \$3.8 million. Finally, this table shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

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TABLE 2.3-2

PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC (\$ Million)

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Fort Greely, Alaska

SCENARIO 1 (Base)*	Current <u>1985</u>		<u>ected</u> 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh) Thermal (billion Btu)	15.7 240	15.9 240	16.0 242	160 2447
Total Energy Cost				
Cost without GFC Cost with GFC		5.0 4.2	6.5 5.5	64.0 53.7
GFC Energy Cost Comparison				
Cost of Energy from GFC Cost of Same Energy and O&M Without GFC		3.0 3.8		38.5 48.8
Cost Savings with GFC		.8	1.0	10.3
SCENARIO 2:** Cost Savings wi	th GFC	.8	1.2	12.2
SCENARIO 3:*** Cost Savings wi	th GFC	1.3	2.0	19.2

* Flat near-term fossil fuel prices. 5% long-term escalation.

** Flat near-term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

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2.3.2 <u>Economics</u>

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The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the CFC plant return on investment (ROI) results.

2.3.2.1 Capital Costs

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. However, noting that there is a substantial premium for construction in Alaska due to higher labor costs, transportation costs and severe climate, it is proposed that this differential of about \$28,000,000 be funded by the Federal Government. This would in effect, raise the percentage funded by the government to 80% of capital cost. Under this arrangement, the government capital contribution would be \$64.9 million and private contribution \$16.2 million, as shown in Table 2.3-3. These shares are derived as follows.

The estimated GFC plant construction and preproduction costs (1985 dollars) are \$66.0 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various states, these costs escalate to a total of \$77.2 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1978-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs.

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Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest. 「いいいいいいい」

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Fort Greely site for these items is \$2.0 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at \$1.9 million (fixed) for the project. These include:

- o Financing fees of \$1.3 million, or 8% of the private capital requirement.
- o Third party development fee of \$300,000, or 2% of the private capital.
- Legal and other expenses of \$300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Ft. Greely project, then, are \$81.1 million. Table 2.3-3 shows the percentage and timing breakdown of these requirements for the private and governmental portions of \$16.2 and \$64.9 million respectively.

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TABLE 2.3-3

GFC PLANT CAPITAL REQUIREMENTS (\$ Million)

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Fort Greely, Alaska

	1985 Dollars			ts Assur alation 1989	
Construction Costs					
GFC Plant Equipment	51.5				
GFC Plant Civil	12.7				
Preproduction Costs	1.7				
Subtotal	65.9	14.9	30.4	31.9	77.2
Other Costs					
Construction Interest				0*	0
Working Capital				2.0	2.0
Development, Financing, Legal and Other				1.9	<u>1.9</u>
Subtotal					<u>3.9</u>
TOTAL CAPITAL REQUIREMENTS		14.9	30.4	35.8	81.1
At a 20/80 Mix of Capital Contributions: **					
Private Capital				16.2*	16.2
Government Capital		14.9	30.4	19.6	64.9
* Private capital would be l construction, but would be cor Therefore, construction interes be zero.	ntributed as	the las	it fund:	ing inc	rement.

**80 percent government contribution determined as follows:

100% of \$28 million special site civil, equipment, and 28.0 labor costs accruing to Alaskan Army base location

70% of \$53.1 million remaining costs 36.9

TOTAL

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2.3.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the GFC site, the GFC plant outputs are electric power, steam and 10% excess coal fines received that cannot be handled by the coal gasification equipment. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

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The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price received for the power sold. For Fort Greely the GFC plant provides all of the site power requirements, and the excess GFC plant power is sold to the utility, GVEA. The price for the power is set at the purchased power cost for the site, which currently 8.43¢/kWh (total electric power bill divided by the number of kWhs). It would increase to 10.8¢/kWh by 1990, assuming a 5% escalation rate. The assumed sale price of the power to GVEA in 1990 is 8.9¢/kWh. Under the base scenario, the long-term escalation rate of both the displaced purchased power cost and the sale price to GVEA is assumed at 5%/year. The 8.9¢/kWh 1990 price to GVEA, and the 5%/year escalation escalation rate is based on the minimum value assigned to the cost of new capacity that will be needed on GVEA's system in the 1990s, preferably in the Fort Greely geographic area.

The electric energy produced by the GFC plant is estimated at 72 kWh in 1990, increasing to over 77 million kWhs in 1995 from increase in the number of estimated operating hours. The increase in operating hours is based on the assumption that, with some substantial operatng experience, the plant availability should increase. The electric revenues for the power sold from the GFC plant are estimated at \$6.7 million in 1990, increasing to \$9.2 million in 1995, and totalling almost \$90 million for the first 10 years of plant life.

The amount of steam sold to Fort Greely by the GFC plant is estimated at 167 million pounds per year in 1990, increasing to 179 million pounds per year in 1995. the price assumed for sale of the steam is \$6/thousand

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pounds (1985 dollars), which is less than it costs to produce it on-site. The cost of boiler fuels and labor are significant in Alaska (the fuel oil cost is approximately 40-50% higher than the lower 48 states). The steam price in 1990, assuming a 5% escalation rate, would be \$7.7/thousand pounds, increasing to \$9.8/thousand pounds by 1995, and escalating at 5% (under the base scenario) in the long-term. The estimated steam revenues in 1990 are \$1.3 million, increasing to \$1.8 million in 1995, and approximating \$16 million for the ten years, 1990-1999.

The excess coal fines contained in the coal received are unusable in the coal gasifier (which can take up to 15% of fines in the coal mix handled). Approximately 10% of the coal received would be resold as excess fines. Assuming a delivered coal price to Fort Wainwight to complete with the \$/million Btu delivered prices of other coal, a 1985 coal fines price of \$34/ton f.o.b. Greely was assumed. At a 5% per year escalation rate, the 1990 coal price would be over \$43/ton. This would provide coal fines sale revenues in 1990 of \$420,000, increasing at 5% in the long-term, under the base scenario assumptions.

Table 2.3-4 shows the electric power, and steam production for the GFC plant for the first and sixth years of operation, and cumulatively for the first ten years of operation.

Both O&M and the fuel costs are significant. The O&M cost assumptions were explained in Section 2.1.2. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is \$260,000, assumed to escalate at 5% per year long-term.

Using a coal price of \$39 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the Scranton GFC plant is estimated at \$3.2 million. With a 5% escalation, and an increase in plant operaing hours starting in the sixth year, the estimated cost in 1995 is \$4.1 million.

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GFC PLANT ECONOMIC OUTPUT (\$ Million)

Fort Greely, Alaska Site

Economic Parameter	First 1985 (1990)	Sixth Year (<u>1995</u>)	First 10 Years Operation (1990-1999)
Electric Power Output			
Net Power Output (MW) Operating Hours per years Energy Sold to Site (Mil kWhs) Price (¢/kWh) Energy Sold to Utility (Mil kW Price (¢/kWh)	10.8	10.2 7596 16.0 13.7 61.4 11.4	160 588
Steam Output (at 240 psig)			
Output Rate 1000 lb/hr) Sold to Site (Mil Lbs) Price (\$/000 Lbs)	23600 167.5 7.7	23600 179.3 9.8	1734
Other Output			
Coal Fines Sold (Bil Btu) Price (\$/Ton)	145 43	155 55	1599

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investiment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

o 10% investment tax credit.

- o 5-year straight line depreciation.
- o 50% combined federal and state marginal annual income tax rate.
- o As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.3.2.3 Return on Investment

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For the basic economic analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment decision results. Rather, they are an indicator of the

^{*} With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce the marginal annual income tax rate, a measure that would increase the ROI in the long-term.

potential economic attractiveness of the GFC plant. The ROI results is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing anaysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- o The value of a maximum price guarantee to be provided by the GFC plant that would not be avaiable from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not optimized in this feasibility study. The purpose of the next state -preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operting costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30%, based on an expected production volume capital cost for the GFC plant at 30% of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors.

Therefore, a feasibility ROI criterion of 10%, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts an ROI number such that general comparisons with other ROIs are harder to make. The 10% ROI criterion roughly translates into a 25% or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio.

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(Alternative financing structures and the ROE results are discussed in Section 3.0, Financing and Ownership Analysis.)

As shown in Table 2.3-5, the total GFC plant revenues for Fort Greely in 1990 are estimated at \$8.4 million, and total costs at \$6.0 million, resulting in an operating cash flow of \$2.4 million. This operating cash margin increases steadily, with a 10-year total operating cash flow of approximately \$34 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a slight tax savings. Therefore, the net cash flow in 1990 is slightly greater than the operating cash flow. However, starting in 1995, a tax payment of 50% of the operating cash flow occurs.* Overall, the net cash flow is fairly steady at \$2.0-\$2.5 million during the first ten years of plant life, with a total 10-year cash flow of almost \$24 million.

The resulting ROI under the base scenario is approximately 11%. The results under Scenario 2 (flat near-term fossil prices and high, sustained long-term prices) is 16%. Under Scenario 3, with a 5% annual increase in near-term fossil energy prices, and high, sustained long-term escalation rates, the ROI is 10%.

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^{*} The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2	2.3-5
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GFC PLANT CASH FLOW SUMMARY

Fort Greely, Alaska Site

Economic Variable	1990)	1995	10-Year Total (1990-1999)
Base Scenario			
Revenue Electric Other Subtotal	6.7 <u>1.7</u> 8.4	9.2 <u>2.2</u> 11.4	87.9 <u>21.4</u> 109.3
Cost Fuel O&M & Other Subtotal	3.2 2.8 6.0	4.1 <u>3.6</u> 7.7	40.2 35.4 75.6
Operating Cash Flow Tax Saving (Payment) Net Cash Flow	2.4 <u>.3</u> 2.7	3.7 <u>-1.9</u> 1.8	33.7 <u>-9.5</u> 24.2
ROI	11.1%		
Scenario 2			
Net cash flow	2.7	2.5	30.9
ROI	15.7%		
Scenario 3			
Net cash flow	2.2	1.8	23.9
ROI	9.9%		

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2.3.3 Conclusions

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The analysis of the Fort Greely site led to the following conclusions:

- Potential site thermal and O&M savings could be significant, approximating 15% of the project site energy costs, and providing a certainty in energy prices not available from other fuel suppliers and the electric utility.
- 2. The Westinghouse GFC plant configuration did not provide acceptable economics because of lower economies of scale for a smaller plant and a lower efficiency than the UTC configuration.
- 3. For a set of energy prices that provides Fort Greely a 15% cost savings, the minimum GFC plant after-tax return on total investment indicator exceeds 10%, and promises the potential to exceed 15% through further work that optimzes the technical design and economics.
- 4. The addition of new GFC capacity in the 1990's in the Fort Greely area would be of significant value to GVEA and would also be available for use by Fort Wainright to handle increased electrical demand with the stationing of additional military personnel.

2.4 Fort Hood, Texas Site

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The Fort Hood Texas site was described in previous reports (CLIN 000203 and CLIN 000303). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this chapter contains the following sections:

- 1. Site costs/benefits
- 2. Economics
- 3. Conclusions

2.4.1 Site Costs Benefits

The benefits to Fort Hood can occur through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.4.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analysis of GFC benefits to the site, 25-year projections were made of energy use and costs without the GFC for the years 1990-2009.

The cost factors projected are as follows:

<u>Electric Energy</u>. Currently, Fort Hood consumes about 290 million kWhs per year of electric energy. The escalation in kWh use is expected to be moderate. 2% per year was assumed in the near-term, providing about 320 million kWhs in 1990. A 2% escalation rate was assumed for the long-term as well.

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The current electric energy (kWh) rate is 3.7 e/kWh in the near-term (1985-1990). A 5% escalation rate was assumed for all scenarios. This would provide a rate of approximately 4.7e/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for a summary of assumptions made for each scenario.)

The current annual electric energy cost is about \$10.7 million. Under the above assumptions, it would increase to \$15.1 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

<u>Electric Demand</u>. Currently, Fort Hood has a peak electric demand of about 68 MW. It was assumed this would increase at a moderate rate of 2% per year, both in the near-term and long-term.

The current demand charge is approximately \$4.2/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of \$5.4/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the annual electric demand cost is about \$3.5 million. Under the assumptions used above, this would increase to \$4.9 million by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently \$1.4 million, likely to increase to \$2.0 million by 1990.

<u>Natural Gas</u>. Currently, about 1650 million cubic feet of natural gas are consumed annually by Fort Hood. Assuming this usage increases by 2% per year, an assumption consistent with the total energy use projections made for the site, the natural gas required would increase to over 1830 cubic feet by 1990, with a long-term escalation of 2% per year.

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The current cost of natural gas is about \$4.2 per mcf (40¢ per therm). Under the first (base) scenario analysis, it was assumed this price would stay flat through 1990, then increase in the long-term at 5% per year. While even near term decreases in natural gas (and oil) costs could occur, given the current softness of those prices, the first scenario provides a reasonably low level of natural gas prices over the 20-year time frame, 1990-2009.

The current annual gas cost of \$6.9 million would increase to about \$7.6 million by 1990 under the base scenario assumption.

<u>Operating and Maintenance Costs</u>. Incomplete information was available on the amount of energy-related O&M costs for Fort Hood. Based on the experience of the team and on data available from other Army sites, a current O&M cost of \$1 million per year was assumed. This was assumed to increase at 5% per year (inflation) to \$1.3 million per year by 1990, and to increase by 5% per year thereafter (under the first scenario).

Total Site Energy Costs. The total annual energy-related costs for Fort Hood are currently about \$22 million. Under the first scenario, these costs would increase to \$29 million in 1990, and would increase to over \$50 million per year in 1999. The total cost for the ten years, 1990-2009, would approximate \$400 million.

Exhibit 14 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.4.1.2 Cost/Benefits With the GFC

The cost savings to Fort Hood can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility.

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TABLE 2.4-1

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SUMMARY - SITE ENERGY USE/UNIT PRICE PROJECTIONS -Scenario 1 (Base) Fort Hood, Texas

Energy Parameter	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>	<u>1988</u>	<u>1989</u>	<u>1990</u>	1990–2009 Escalation Rate
Electric Power								
Energy (Mil kWhs) Rate (¢/kWh)	284 3.5	290 3.7	295 3.9	301 4.1	307 4.3	314 4.5	320 4.7	2% 5%
Demand (MW) Rate (\$/kW/Mo)	66 4.0	68 4.2	69 4.5	71 4.7	72 4.9	73 5.2	75 5.4	2% 5%
Overall Rate (\$/kW)	4.7	4.9	5.2	5.4	5.7	6.0	6.3	
Fuels								
Natural Gas (Mil Mcf) Price (\$/Mcf)	1620 4.2	1652 4.2	1685 4.2	1719 4.2	1753 4.2	1788 4.2	1824 4.2	2% 5%
Fuel Oil (Mil gal.) (Price (\$/Gal.)	NA NA							
Coal (000 Tons) Price (\$/Ton)	NA							
O&M Cost (\$ Mil)	1.0	1.0	1.1	1.2	1.2	1.3	1.3	5%
Total Energy- Related Costs (\$ Million)	21.0	22.1	23.3	24.6	26.0	27.4	28.9	

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The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

The site would have O&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Fort Hood were primarily the result of the difference in cost between steam purchased from the GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing gas fired boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and naot electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. However, this was not the case for Fort Hood.

Fort Hood currently consumes 1.2 billion pounds of steam per year. At an assumed 2% growth rate, this amount would increase to over 1.3 billion pounds per year by 1990. For the Fort Hood GFC feasibility design, the GFC plant steam output is 144 million pounds per year (see CLIN 000303). The assumed GFC purchase price by Fort Hood for this steam (in 1985 dollars) is \$4 per thousand pounds, less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be \$5.10 per thousand pounds in 1990, the first year of GFC plant operation.

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Under the base scenario, this price was assumed to escalate at 5% per year in the long-term as well.

With a partial steam purchase from the GFC, Fort Hood's direct cost of purchased fuels in 1990 would be reduced slightly, by about \$100,000, and the electric power cost would be reduced \$200,000 through the use of steam in an absorption chiller. The 1990 O&M could be reduced by \$500,000.

The total savings in 1990 under these assumptions is estimated at \$800,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over \$1.3 million per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate \$10 million.

These savings are likely the minimum that would be achieved, since the first scenario is likely to produce lower energy costs without the GFC plant than most experts think will occur through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be \$12-\$16 million for the ten-year period. Table 2.4-2 is a summary of the projected site energy use, costs, and savings with the GFC plant which also shows the total site energy costs without the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, a GFC energy cost comparison is shown next on the exhibit. For 1990, the cost of the GFC electric power and thermal energy purchased, combined with the O&M savings that would likely occur is \$5.7 million, whereas the cost of these fuels and O&M costs without the GFC is estimated at \$6.5 million. Finally, the exhibit shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

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SUMMARY - PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC PLANT (\$ Million) Fort Hood, Texas

<u>SCENARIO 1</u> (Base)*	Current _ <u>1985</u>	Proje 1990	<u>1995</u>	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	290	320	353	3502
Thermal (billion Btu)	1276	1409	1556	15427
Total Energy Cost				
Cost without GFC		28.9	40.6	400
Cost with GFC		28.1	39.6	390
GFC Energy Cost Comparison				
Cost of Energy From GFC		5.7	7.0	74.0
Cost of Same Energy and O&M Without GFC		6.5	8.1	84.4
Cost Savings with GFC		.8	1.1	10.4
SCENARIO 2: **Cost Savings with (GFC	.8	1.3	12.4
SCENARIO 3: ***Cost Savings with	GFC	1.0	1.6	16.0

* Flat near-term fossil fuel prices. 5% long-term escalation.

** Flat near-term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

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2.4.2 Economics

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The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

2.4.2.1 Capital Cost

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be \$35.7 million and the private contribution \$15.3 million. However, because the GFC economics do not provide for a privately financable plant, development of a GFC plant at Fort Hood is not recommended and no governmental funding is warranted.

To appreciate the basic economic analysis, a description of the total capital requirements is provided. The estimated GFC plant construction and preproduction costs (1985 dollars) are \$40.7 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of \$47.6 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Scranton AAP site for these items is \$1.6 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at \$1.8 million (fixed) for the project. These include:

- o Financing fees of \$1.2 million, or 8% of the private capital requirement.
- o Third party development fee of \$300,000, or 2% of the private capital.
- o Legal and other expenses of \$300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Fort Hood project, then, are \$51.0 million. Table 2.4-3 shows the timing of these capital requirements.

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TABLE 2.4-3

SUMMARY - GFC PLANT CAPITAL REQUIREMENTS (\$ Million) Fort Hood, Texas

	1985 Dollars			osts Assu calation 1989	
Construction Costs			1,000	1,0,	-0041
GFC Plant Equipment	36.2				
GFC Plant Civil	3.5				
Preproduction Costs	1.0				
Subtotal	40.7	9.1	18.8	19.7	47.6
Other Costs					
Construction Interest				0*	0
Working Capital				1.6	1.6
Development, Financing, Legal and Other				1.8	1.8
TOTAL CAPITAL REQUIREMENTS		9.1	18.8	23.1	51.0
Mix of Capital Contributions:					
Private Capital		not re	commende	. GFC p d on eco	
Government Capital		grounds.			

* Private capital would be legally commited at the beginning of constrction, but would be contritubed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

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2.4.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the Fort Hood site, the GFC plant outputs are electric power and steam. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price received for the power sold. In this case, the entire electric power output is assumed sold to Fort Hood at its cost of displaced power -- 6.2¢ kWh in 1990, escalating at 5 percent/year to 8.0¢/kWh in 1995. In the analysis, the long-term escalation rate was assumed at 5 percent or 10 percent per year, depending on the scenario analyzed.

The GFC electric energy sold to Fort Hood is estimated at 79 million kilowatt hours per year in the first five years of operation, increasing to approximately 84 million kilowatt hours thereafter. The assumption behind this increase is that, with operating experience, the plant availability should increase after some period of operation.

The total electric revenues to the GFC plant corresponding to this output are \$4.9 million in 1990, increasing to \$6.7 million in 1995 in accordance with the increased kWh output and the increased rates. The ten-year revenues for the plant are estimated at \$64 million.

The remaining revenues for the plant are steam revenues. The annual amount of steam sold upon startup of the GFC plant is 20300 thousand pounds per hour and 144 million pounds per year, increasing to 154 million pounds per year in 1995 and after. In accordance with the \$5.10/000 lb steam price assumption and discussed earlier, the expected annual revenues in 1990 are \$700,000-800,000, increasing to \$1 million in 1995. The ten year stream of steam revenues is estimated at \$9.6 million.

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Table 2.4-4 shows the key electric power and other output assumptions for the GFC plant for the first and sixth years of operation, and cumulatively for the first ten years of operation.

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SUMMARY-GFC PLANT ECONOMIC OUTPUTS

Economic Parameter	First Year (1990)	Sixth Year (1995)	First 10 Years Operation (1990–1999)
Electric Power Output			
Net Power Output (MW)	11.1	11.1	
Operating Hours per year	7096	7596	
Energy Sold to Site (Mil kWh)	78.8	84.3	185
Price (¢/kWh)	6.2	8.0	
Energy Sold To Utility (Mil kWhs)	0	0	0
Price (¢/kWh)	NA	NA	
Steam Output (at 240 psig)			
Output Rate (1000 Lbs/hr)	20300	20300	
Sold to Site (Mil Lbs)	144	144	1490
Price (\$/1000 Lbs)	5.10	6.50	
Other Output			
Tars/Oils Sold (Bil Btu)	NA	NA	NA
Price (\$/Mil Btu)			

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Both the O&M and the fuel operating costs are significant. The \$2 million 1985 O&M cost estimate was explained in Paragraph 2.1.2. With 5 percent escalation, the 1990 O&M cost would be \$2.5 million. In 1995 (sixth operating year), the fuel cell reload costs start, adding (\$600,000 per year for a total 1995 O&M of \$3.9 million. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is \$260,000, assumed to escalate at 5 percent year long-term.

Using a lignite coal price to \$35 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for year years), the 1990 coal cost for the GFC plant is estimated at \$3.0 million. With a 5 percent escalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is \$3.8 million.

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

- o 10 percent investment tax credit.
- 0 5-year straight line depreciation.
- o 50 percent combined federal and state marginal annual income tax rate.

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^{*} With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce the marginal annual income tax rate, a measure that would increase the ROI in the long-term.

 As a sensitivity analysis, the impact of the annual income tax credit (through (1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.4.2.3 Return on Investment

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For the basic economic analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing analysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plat were not optimized in this feasibility study. The purpose of the next stage -preliminary design and teating -- is to identify improvements in the capital cost. Also, the private cost-sharing component, which is a

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significant strength of the GFC concept, has been roughly set at 30 percent, based on an expected production volume capital cost for the GFC plant at 30 percent of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

Therefore, a feasibility ROI criterion of 10 percent, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts the ROI such that general comparisons with other ROIs are harder to make. The 10 percent ROI criterion roughly translates into a 25 percent or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio.

As shown in Table 2.4-5, the total potential GFC plant revenues for Fort Hood in 1990 are estimated at \$5.7 million, and total costs at \$5.8 million, resulting in a breakdown cash flow. This operating cash margin is slightly negative over the operating life of the GFC plant.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a tax savings. Therefore, the net cash flow in 1990 would be \$1.3 million. However, starting in 1995, a tax product of 50 percent of the operating cash flow occurs and the subsequent net cash flows are slightly negative.* The estimated 10-year cash flow is 5-6 million

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^{*} The annual income tax credit for nonconvential sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

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Table 2.4-5

GFC PLANT ECONOMICS SUMMARY

Economic Variable	1990	1995	10-Year Total (1990-1999) -
Base Scenario			
Electric	4.9	6.7	54.4
Other		1.0	_9.6
Subtotal	5.7	7.7	74.0
Cost			
Fuel	3.0	3.8	37.3
O&M & Other	_2.8	4.2	38.7
Subtotal	5.8	8.0	76.0
Operating Cash Flow	1	3	-2.0
Tax Saving (Payment)	1.4	.1	
Net Cash Flow	1.3	2	5.6
ROI	Negataive		
Scenario 3			
Net Cash Flow	.9	3	4.4
ROI	Negative		

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2.4.3 <u>Conclusions</u>

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The analysis of the Fort Hood site led to the following conclusion:

 For a set of energy prices that provides Fort Hood any significant cost savings, the GFC plant after-tax return on total investment is unacceptable. Therefore an economically viable application for the GFC plant does not exist.

2.5 WASHINGTON, DC SITE

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The Georgetown University site was described in previous (CLIN) 0002 and CLIN 0003). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this chapter contains the following sections:

- 1. Site costs/benefits.
- 2. GFC plant economics.
- 3. Conclusions.

2.5.1 Site Costs/Benefits

The benefits to Georgetown University (GU) can accrue through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.5.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analysis of GFC benefits to the site, 25-year projections were made of energy use and costs without the GFC for the years 1990-2009. The cost factors were projected as follows:

<u>Electric Energy</u>. Currently, GU consumes about 75 million kWhs per year of electric energy. Based on GU's 5-year plan, the kWh use is expected to increase steadily, reaching 120 million kWhs by 1990. A 3% escalation rate was assumed for the long-term.

The current average electric energy (kWh) rate is 3.8¢/kWh. While scenarios were evaluated with alternative energy price escalation rates, in the near-term (1985-1990), a 5% annual escalation rate was assumed for all scenarios providing a rate of approximately 4.8¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for the complete set of assumptions made for each scenario.)

The current annual electric energy cost is about \$2.5 million. Under the above assumptions, it would increase to \$5.3 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

<u>Electric Demand</u>. Currently, GU has a peak electric demand of about 11.9 MW. Based on the 5-year plan, it was assumed this would increase to about 16 MW by 1990, escalating at 5% thereafter (Scenario 1).

There are two demand charges -- a ratcheted 12-month distribution charge and a monthly summer charge. These are currently \$6/kW/mo and \$9.7/kW/mo respectively. In the near-term in all scenarios, it was assumed this would increase at 5% per year. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about \$1.2 million annually. Under the assumptions used above, this would increase to \$2.1 million by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently \$3.6 million, likely to increase to \$7.5 million by 1990.

<u>Coal</u>. GU has a fluidized bed coal boiler and a recently completed cogeneration plant. Its intended output is 9.6 million kWh and 600 million pounds of steam per year. This would require an annual coal supply of almost 35,000 tons of bituminous coal. This cogeneration plant would have a steady output, and thus a steady coal requirement.

The current cost of the coal is \$51 per ton. In addition, for each ton of coal, a limestone supply cost of \$9.30 and an ash removal cost of \$2.45 are required, bringing the total fuel-related cost for the plant to approximately \$63 per ton. Under the first scenario, it was assumed this cost will stay constant through 1990, increasing at 5% thereafter. Thus,

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the total annual coal cost under this scenario in 1985 and 1990 is \$2.2 million. The largest increase in cost occurs under the third scenario, where a 5% near-term escalation rate and a 10% long-term annual escalation rate were assumed.

Natural Gas. Prior to 1985 only a limited amount of natural gas was used. However, under very competitive prices offered by the natural gas company, GU has contracted for a substantial amount of natural gas in 1985-1986, as much as 400 million cubic feet. This supply arrangement is a year-to-year arrangement. Given the likely continued competitiveness of natural gas with fuel oil, it was assumed for long-term analysis that a fixed annual amount of 155 million cubic feet per year would be contracted for, with the marginal fuel requirements served by No. 6 fuel oil.

The current price paid for natural gas is \$4.12 per thousand cubic feet (about 40¢ per therm). Under the first scenario this price is assumed flat through 1990, then escalates at 5% per year. Thus, in 1990 the annual natural gas cost would be between \$600,000 and \$700,000.

<u>Fuel Oil</u>. Compared with the early 1980s, very little fuel oil is currently used. However, fuel oil will be the marginal fuel over the foreseeable future, and by 1990 approximately 650,000 gallons per year could be required.

The No. 6 fuel oil price is currently 63¢ per gallon (\$4.20 per million Btu). As such, the price is roughly equal to the natural gas price per million Btu. The expected cost of fuel oil in 1990 would approximate \$400,000.

Since the amount of coal consumed will be fixed, and the price per million Btu of natural gas and fuel oil is approximately the same, a different mix of natural gas versus fuel oil use would not significantly change the results of the energy cust analysis.

Operating and Maintenance Costs. Currently, GU spends \$1.9 million for its energy-related O&M. Under the 5-year plan, this is expected to grow to about \$2.5 million in 1990. It was assumed that O&M will escalate at

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5% annual thereafter. A higher long term escalation rate was analyzed in Scenarios 2 and 3.

Total Site Energy Costs. The total annual energy related costs for GU are almost \$8 million. Under the first scenario, these costs would increase to \$13.2 million in 1990, and would increase to over \$25 million per year by 1999. The total cost for the ten years, 1990-2009, would approximate \$190 million.

Table 2.5-1 shows the projected near term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.5.1.2 Costs/Benefits With the GFC

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The cost savings to GU can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility. The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

The site would have D&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the D&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the D&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The DFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

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Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings were primarily the result of the different in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. However, this was not the case for the GU site feasibility analysis. Therefore, it was assumed the GFC plant would displace GU's purchased power at the same price.

GU currently consumes about 600 million pounds of steam per year. At an assumed 5% growth rate, this amount would increase to approximately 770 million pounds per year by 1990. For the GU GFC feasibility design, the GFC plant steam output is small, about 14.2 million pounds per year (see CLIN 3). The assumed purchase price by GU for this steam (in 1985 dollars) is \$4 per thousand pounds, less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be \$5.10 per thousand pounds in 1990, the first year of GFC plant operation. Under the base scenario, this price was assumed to escalate at 5% per year in the long-term as well.

Given the small amount of steam purchased from the GFC plant, the \$3.2 million cost for purchased fuels in 1990 would be reduced less than \$100,000. But the reduction in O&M could be more significant through absorption of O&M costs by the GFC plant, saving \$500,000 of the \$2.5 million projected O&M.

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TABLE 2.5-1

SITE ENERGY USE PRICE AND COST PROJECTIONS - Scenario 1 (Base)

Washington, D.C.

1990-2009 Escalation Rate		ጽድ እ	۲ א א	۴		88	Note 2 5%	25	8 2	
1990		122 4.8	15.9 7.7	1.4 6.1		155.3 4.1	0.6 .63	34.6 62.8	2.5	13.2
1989		116 4.6	15.1 7.3	5.8		155.3 4.1	0.3 .63	34.6 62.8	2.4	12.1
<u>1988</u>		108 4.4	14.4 6.9	5.5		126.7 4.1	0.1 .63	34.6 62.8	2.3	11.0
1987		10U 4.1	13.1 6.6	5.2		78.2 4.1	0.1 .63	34.6 62.8	2.2	6*6
1986		87 3.9	11.9 6.3	5.0		31.9 4.1	0.1 .63	34.6 62.8	2.0	8.7
1985		75 3.7	11.9 6.0	4.9		7.3 4.1	Small .63	34.6 62.8	1.9	7.8
1984		75 3.3	12.5 5.4	4.9		7.1 6.4	3.2 .77	11.5 62.8	1.5	8.4
Energy Parameter	Łlectric Power	Energy (Mil/kWh) Rate (¢/kWh)	Uemand (MW) Rate (\$/kW/MD)l	Overall Rate (\$/kWh)	Fuels	Natural Gas (Mil Ft) ² Price (\$ /Mcf)	Fuel Oil (Mil Gal) ² Price (\$ /Gal)	Coal (1000 Tons) Price (\$ /Ton) ³	O&M Cost (\$ Mil)	Total Energy - Related Costs (\$ Million)

1*0 demand charges apply, an 11-month ratcheted distribution charge and a monthly summer production/transmission charge. _

Special natural gas purchase opportunities exist on a year-to-year basis. For purposes of <u>long-term</u> analysis (1990-2009), a maximum of 160 bil Btus (155.3 million ft³) was assumed, with fuel oil as the marginal fuel. Since the assumed prices (\$/Mil Btu) are within 5 percent of each other, a different gas/oil mix would not change the results of the analysis. 2

Coal cost includes coal and the costs per ton for limestone and for ash disposal. m

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The total estimated savings in 1990 under these assumptions is \$600,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to \$800,000 per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate \$7 million.

These savings are likely the minimum that would be achieved, since the first scenario is likely to produce lower energy costs without the GFC plant than most persons think will occur through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be over \$8 million for the ten-year period. Table 2.5-1 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the power purchased from the GFC. Accordingly, a GFC energy cost comparison is shown next to the exhibit. For 1990, the cost of the GFC electric and thermal energy purchased, combined with the O&M savings that would likely occur, is \$5.2 million, whereas the cost of these fuels and O&M costs without the GFC is estimated at \$5.8 million. Finally, the exhibit shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

2.5.2 Economics

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The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

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PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC PLANT (\$ Million)

Washingt	on, D.C.			
Scenario 1 (Base)*	Current 1985	<u>Proje</u> 1990	<u>ected</u> 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	75	122	1 31	1399
Thermal (billion kWh)	635	811	940	1058
Total Energy Cost				
Cost without GFC		13.2	19.5	192.2
Cost with GFC		12.6	18.8	157.7
GFC Energy Cost Comparison				
Cost of Energy from GFC Cost of Same Energy and O&M Without GFC		5.2 5.8	7.1 7.8	67.9 75.0
Cost Savings with GFC		.6	.7	7.1
Scenario 2:** Cost Savings with GFC		.6	.8	8.2
Scenario 2:*** Cost Savings with GFC		.6	.8	8.6

* Flat near-term fossil fuel prices. 5 percent long-term escalation. ** Flat near-term fossil fuel prices. 10 percent long-term escalation. *** Fossil fuel prices 5 percent near term, 10 percent/year long-term.

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2.5.2.1 Capital Costs

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Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be \$44.3 million and the private contribution \$20 million.

The estimated GFC plant construction and preproduction costs (1985 dollars) are \$50.4 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of \$59 million installed by the end of 1989. The construction cash flow is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumed debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the GU site for these items is \$2.1 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at \$2.3 million (fixed) for the project. These include:

- Financing fee of \$1.5 million, or 8% of the private capital requirement.
- o Third party development fee of \$380,000, or 2% of the private capital.
- Legal and other expenses of \$380,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Washington, D.C. site, then, are \$63.4 million. Table 2.5-3 shows the percentage and timing of these requirements for the private and governmental portions.

2.5.2.2 Plant Energy Production

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The margin provided by the output revenues and the basic operating cost determined the return on the private capital required. For the Washington, D.C. site, the GFC plant outputs are electric power, steam and tars and oils.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price received for the power sold. The entire GFC plant electric output is sold to GU, displacing its purchase oower from the Potomac Electric Power Company (PEPCO). The assumed price for the GFC power sold is the same as GU's cost of purchased power. In 1990 this is 6.7¢/kWh. (This is the total electric power bill divided by the number of kilowatt hours purchased from PEPCO.) At a long-term escalation rate of 5%, this power price increases to 8.5¢/kWh in 1995.

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TABLE 2.5-3

GFC PLANT CAPITAL REQUIREMENTS (\$ Million)

Washington, D.C.

	1985 <u>Dollars</u>		ed Costs A nt Escalat <u>1</u> 988		
Construction Costs				<u></u>	~
GFC Plant Equipment GFC Plant Civil Preproduction Costs	35.2 14.3 9				
Subtotal	50.4	11.3	23.3	24.4	59.0
Other Costs					
Construction Interest Working Capital Development, Financing, Legal and Other				0* 2.1 2.3	0 2.1 2.3
Subtotal					4.4
TOTAL CAPITAL REQUIREMENTS		11.3	23.3	28.8	63.4
At a 30/70 Mix of Capital Contributions:					

Private Capital Government Capital Not applicable. GFC plant not recommended on economic grounds.

* Private capital would be legally committed at the beginning of construction, but would be contributed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

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The amount of electric energy sold annually to GU is 77 million kWhs in the first five years of GFC plant operation, increasing to over 82 million kWhs in the sixth year and later years of operation, for a total of almost 800 million kWhs over the first ten years of plant life. The rationale for the increase in output is that, with some solid operating experience, the GFC plant availability should increase.

The total electric revenues to the GFC plant are estimated at \$5.1 million in 1990, \$7 million in 1995, and \$67 million for the first ten years of plant life.

The other revenues for the GFC plant come from the sale of steam and the sale of tars and oils (similar to residual fuel oil) produced in the process, and not used internally. The limited amount of steam (200 pounds per hour and 14 million pounds per year) would produce 1990 revenues of less than \$100,000 per year. The substantial amount of tars and oils produced as a by-produuct of the plant are assumed to be sold at the price of No. 6 fuel oil (63¢ per gallon in 1990), providing revenues of over \$1 million. The estimated total GFC plant revenues for 1990, then, are \$6.3 million, and over \$80 million during the first ten years of plant life.

Exhibit 22 shows the key electric power and other output assumptions for the GFC plant for the first year and sixth year of operation, and cumulatively for the first ten years of operation.

Both the O&M and the fuel operating costs are significant. The basis for the \$2 million 1985 O&M cost estimate was given in para. 2.1.2. With 5 percent escalation, the 1990 O&M cost would be \$2.6 million. In 1995 (sixth operating year), the fuel cell reload costs start, adding \$600,000 per year, for a total 1995 O&M of \$3.9 million. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is \$260,000, assumed to escalate at 5 percent per year long-term.

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TABLE 2.5-4

SUMMARY - GFC PLANT ECONOMIC OUTPUTS

Washington, D.C.

	First Year	Sixth Year	First 10 Years Operation
Economic Parameter	(1990)	(1995)	(1990-1999)
Electric Power Outuput			
Net Power Output (MW)	10.8	10.8	
Operating Hours Hours per year	7096	7596	
Energy Sold to Site (Mil kWhs)	77.0	82.4	797
Price (¢/kWh)	6.7	8.5	
Energy Sold to Utility (Mil kWhs)	0	0	0
Price (¢/kWh)	NA	NA	
Steam Output (at 240 psig)			
Output Rate (1000 Lbs/Hr)	2000	2000	
Sold to Site (Mil Lbs)	14.2	15.2	147
Price (\$/000 Lbs)	5.1	6.5	
Other Output			
Tars/Oils Sold (Bil Btu)	274	2984	2841
Price (\$/gal)	.63	.80	

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Using a coal price of \$62 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the GU GFC plant is estimated at \$3.2 million. With a 5 percent escalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is \$4.0 million.

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

o 10 percent investment tax credit.

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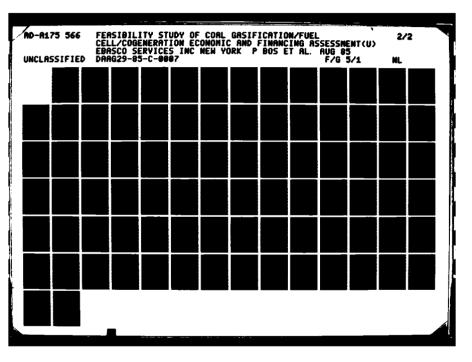
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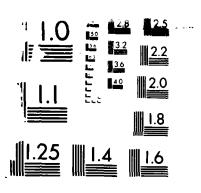
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- o 5-year straight line depreciation.
- o 50 percent combined federal and state marginal annual income tax rate.
- o As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas were evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

^{*} With regard to tax factors affecting the GFC plant economies, the overall thrust of the current tax proposals is to eliminate or terms the investment tax credit and stretch out the depreciation, the measures that would lower the ROI. The proposals would also terms marginal annual income tax rate, a measure that would increase the in the long-term.





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2.5.2.3 Return on Investment

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For this analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing analysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- o The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not ootimized in this feasibility study. The purpose of the next step -preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operating costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30 percent production volume capital cost for the GFC plant at 30 percent of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

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Therefore, a feasibility ROI criterion of 10 percent, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts an ROI number such that general comparisons with other ROIs are harder to make. The 10 percent ROI criterion roughly translates into a 25 percent or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio. (Alternative financing structures and the ROE results are discussed in Chapter 3.0, Financing and Ownership Analysis.)

As shown in Table 2.5-5, the total GFC plant revenues for GU in 1990 are estimated at \$6.3 million, and total costs at \$6.0 million, resulting in a very limited operating cash flow of \$400,000. This operating margin remains at a low level, with a 10-year total operating cash flow of approximately \$4 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a tax savings. Therefore, the net cash flow in 1990 is \$1.8 million. However, starting in 1995, a tax payment of 50 percent of the operating cash flow occurs.* After the first 5 years, the net cash flow is limited, with a total 10-year cash flow of \$10.4 million.

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^{*} The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2.5-5

GFC PLANT CASH FLOW SUMMARY

Washington, D.C.

Econo	omic Va	ariable	2	<u>1990</u>	<u>)</u>	<u>1995</u>	5	10 Year Total (1990-1999)
Base Scer	<u>nario</u>	(Flat	near-term	fuel	prices.	5 perce	ent long-	term)
Rever	nue							
	Electr Other Subtot			5.1 <u>1.2</u> 6.3		7.0 <u>1.5</u> 8.5		67.0 15.5 82.5
Cost								
	Fuel O&M & Subtot			3.2 <u>2.8</u> 6.0		4.0 <u>4.2</u> 8.2		39.7 <u>38.8</u> 78.5
Operating	g Cash	Flow		.3		.3		4.0
Tax Savir	ng (Pay	/ment)*	•	<u>1.5</u>		<u>1</u>		6.4
Net Cash	Flow			1.8		.2		10.4
ROI	-			Nega	ative			

Scenario 2 (Flat near-term fuel prices. 10 percent/year long-term)

Net Cash Flow

ROI

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<u>Scenario 3</u> (Fuel prices 5 percent/year near term, 10 percent long-term) Net Cash Flow

ROI

Negative

*Does not include the annual syngas tax credit.

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The resulting ROI under the base scenario is negative, as are the ROIs under Scenarios 2 and 3. Sensitivity analysis conducted on electric power and coal prices do not show any potential for improving the economics to an acceptable level.

2.5.2.4 Site Specific Increment

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The site specific incremental cost is estimated to be in the range of \$16,000,000 to \$20,000,000. This additional burden to the basic GFC which is not subject to DOA funding, makes the total plant too costly to continue as the baseline facility.

2.5.3 Conclusions for the Georgetown University Site

The analysis of the Georgetown University site led to the following conclusion:

 For a set a energy prices that provides Georgetown University any significant cost savings, the GFC plant after-tax return on total investment is unacceptable. Therefore, an economically viable application for the GFC plant does not exist.

With the forecast of oil prices in 1990 (63e/gal) this project is not feasible at this site for overall electricity costs below 9.7e/kWh. Since the forecast (Table 2.5-1) indicates the electricity price in 1990 to be 6.1e/kWh, Georgetown University is not proposed as the baseline site.

3.0 OWNERSHIP AND FINANCING ANALYSIS

3.1 <u>General</u>

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In this section, the results of the ownership and financing analysis are presented for the two sites that showed acceptable economic results: Scranton AAP and Fort Greely.

The economic results of both Scranton AAP and Fort Greely indicate that a return on total investment (ROI) of over 10% can be achieved. A summary of the economic results for both sites is shown in Table 3-1.

As with the basic economic analysis, this analysis was intended to determine the financing feasibility of each site, showing that it can or cannot be financed. Financing alternatives selected for each feasible site will be detailed in subsequent stages of GFC project development.

This section also lists key third parties who have indicated serious interest in financing, constructing, owning and operating such a facility.

TABL	E	3-1
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SUMMARY COMPARISON OF SCRANTON AND FORT GREELY ECONOMICS

	Scranton AAP	Fort Greely
Total Capital Requirement		
(\$ Million)	51.0	81.0
Private Capital Contribution		
(\$ Million)	15.3	16.2
1990 After-Tax Cash Flow		
(\$ Million)	2.5	2.7
10-Year After-Tax Cash Flow		
(\$ Million)	23.7	24.2
Return on Investment		
Scenario l*	11.1%	11.1%
Scenario 2*	9.7%	15.7%
Scenario 3***	2.78%	9 .9%

*Flat near-term fossil fuel prices. 5% long-term esclation. **Flat near term fossil fuel prices. 10% long-term escalation. ***Fossil fuel prices 5%/year near term, 10%/year long term.

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The key steps carried out for the ownership and financing assessement were:

1. Identify types of owners and investment decision criteria.

- 2. Identify workable financing alternatives.
- 3. Specify the site financing assumptions.
- 4. Analysis the financing results.
- 5. Identify potential owners, financers, and other participants for each site.

The financial analysis had the two following specific objectives:

- Determine if a Return on Equity (ROE) of at least 25% can be achieved.
- 2. Determine if a debt coverage ratio greater than 1.5 can be provided for the minimum ROE.

Third party financing is defined as the utilization by other nonparticipating parties of the available tax, cost recovery and revenue related incentives to invest and own capital ventures. The third-party may embody corporations, individuals, partnerships, or joint ventures, and may emanate from the private or public sector. The distinguishing feature of third-party financing is the capital provided by the investor is targeted on a project-specific or service-specific basis, as in project financing.

Using this project financing approach, lenders finance a specific project and look to the cash flow generated by that project to service and repay the debt. In "pure" project finance, the lenders have no resource to nor support from, the project's sponsors. However, credit support of some sort from the sponsors or interested third parties are sometimes required. The key to "project financing" is to structure the financing with as little recourse as possible to the sponsors while simultaneously providing sufficient credit support so as to induce the lenders to provide the funds.

Thus, the asset of the project itself serves as collateral to secure the loan, but as a practical matter, assets frequently are project/site specific and thereby would have only minimal reusable value to anyone else. Therefore, the sales contracts for project output becomes a key asset.

The second key feature is the sponsors' desire to limit and minimize their risk and liability for the project debt. Given the size and maturity of a project, the sponsors seek to minimize the impact of the project's financing debt on their balance sheets in order to preserve their financial ratios and debt capacity. In short, the sponsors do not want to borrow directly. Instead, they prefer the project entity itself to incur the debt and carry it on the project's balance sheet.

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The lenders, however, want to finance a credit rather than a venture capital risk and therefore, require credit support and contractual commitments from the sponsors and/or third parties, which effectively mitigate potentially unacceptable business risks. These supports, whether in the form of guarantees, offtake agreements, supply contracts, completion guarantees, undertakings by a third party, system performance insurance, etc., allow the lenders to shift much of the risks to the sponsors and/or third parties. It is very important to bear in mind the "Project Financing" does not eliminate the risks involved; it merely seeks to disperse the risks among all interested parties. To accommodate both the sponsors and the lenders, the developer of a project must assess the risks inherent in the project and structure a credit support framework which assigns those risks among the participants who have an inherent interest to see the oroject go ahead.

There are different types of financing structures that can be used to finance the GFC projects. The most straight forward, and most easily understood, structure is direct, 100% ownership of the plant by a single corporation. This single entity receives all of the net cash flow and all of the tax benefits and liabilities of the project. The entity may choose to obtain debt financing to cover a major portion of the project's capital requirements. It trades off the cash required for the debt service (principal plus interest) against the smaller remaining equity investment it has in the project, and then settles on the optimal amount of debt. (The debt financer, of course, has his criteria and limitations on the maximum amount of debt he is willing to provide.)

A variation on the single owner is a joint venture, where several different owners establish a single legal entity, and share the cash returns and tax benefits of the project in an agreed upon proportion.

Another, completely different structure, is a leasing structure, which has been traditionally used for equipment financing by parties who want no responsibilities or risks for management or operation of the equipment. With this structure, the party leasing the equipment (lessor)

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receives a cash payment for the project manager/operator (lessee) at least as great as the debt service payment required by the debt lendor. The lessor also receives the tax benefits from the project. The manager/operator, or lessee, manages the project, which now has a lease (rental) cost in addition to the operating costs of the project. The residual cash flow after accounting for operating costs and the lease payment is available to the lessee. If the lessor is a financially strong corporation. he can typically obtain a higher amount of debt, and thus more equity leverage, than a directly-owned project financing structure might allow.

There are other, less likely financing structures essentially applicable to the GFC project, such as a large limited partnership, where a special legal entity (the partnership) owns the project and arranges for debt from a lender, much like the direct corporate owner would. But the allocation of the net cash flow and tax benefits to the partnership can be significantly different for different types of partners (e.g. limited vs. general).

Further, the cash flow, tax benefits and liabilities accrue directly to the entities who are the partners and their particular tax positions. These entities can be individuals or corporations.

Regardless of the financing structure, there are two objectives to be met: A minimum ROE of 25%; and a minimum debt service coverage ratio of 1.5.

Pending a further stage of development of the GFC project, and an owner-specific determination of financing interest, the direct 100% corporate ownership structure was assumed, and the results determined under this structure. In the two remaining sections of this chapter, the results of the ownership/financing analyses are discussed for Scranton AAP and Ft Greely.

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3.2 Scranton AAP Ownership/Financing

The following assumptions were made for the Scranton AAP financing analysis:

- o Private capital contribution of 30% of total required capital
- o Debt/equity ratio of 2/1.
- o Debt repaid over 15 years with a constant principal repayment (decreasing total debt service payment).
- o Average interest rate over the life of the loan of 13%.
- o Current tax laws as follows:
 - 1. Ten percent investment tax credit.
 - 2. Five year depreciation.
 - 3. Fifty percent marginal tax rate.
 - Annual income tax credit for synthetic gas analyzed as an incremental benefit.*

Each of the above financing assumptions could be varied, with a significant impact on the resulting ROE. However, within the range of assumptions currently in use for the analysis of similar energy projects. Using the base scenario for energy prices discussed in para 2.2, the ROE for Scranton was 28.5% when including the syngas tax credit.

Refer to Appendix A for details and annual cash flows.

*The annual income tax credit for nonconventional sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculations so that the resulting ROE can be compared to other ROEs reflecting conventional tax assumptions. Referring to Table 3-2 which summarizes these results, the operating cash flow (revenues minus costs) is the same as for the ROI analysis. However, it was assumed that two-thirds of the private capital contribution would be debt with a maximum debt service payment of \$2 million in 1990. Given the interest cost, the taxable income is lower, and the tax savings are higher than for the ROI analysis (no debt). The overall effect on the net cash flow is to reduce it to approximately half of that under the ROI analysis. But, because the equity invested is on-third of the private capital, the return of that cash flow on the equity is 28.5%.

From the debt lender's point of view, a suitable debt coverage ratio is provided. While the minimum debt coverage ratio of 1.5 is not met in the first five years, a coverage ratio of 2.8 - 4.4 is provided in the second five years. The average debt coverage ratio for the first 10 years of plant life is 2.1, as shown in Table 3-2. Thus, the debt structure could be worked around and tailored to the cash flows of the project to provide an acceptable debt coverage ratio for the entire debt service life.

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TABLE 3-2

GFC PLANT ECONOMICS SUMMARY (\$ Million) SCRANTON AAP, PENNSYLVANIA

Economic Vari	able	1990	1995	10-Year Total (1990-1999
Base Secontie	(Elat poor to	m fuel enioce		· · · · · · · · · · · · · · · · · · ·
Dase Scenario	(Flat Hear-te.	rm fuel prices.	5% year to	g-lem)
Revenues:	Electric	7.8	12.0	106.0
	Other	.3	5	4.5
	Subtotal	8.1	12.5	110.5
Costs:	Fuel	3.0	3.8	37.6
	O&M & Other	2.8	4.2	38.8
	Subtotal	5.8	8.0	76.4
Operating Cas	h Flow	2.3	4.4	34.1
Tax Saving (P	'ayment)*	2	-2.2	-10.4
Net cash flow	I Contraction of the second second second second second second second second second second second second second	2.5	2.2	23.7
ROI		11.1%		
<u>Scenario 2</u> (F	lat near-term	fuel prices. 10	0%/year long-	-term)
Net Cash Flow	ı	2.5	1.8	22.5
ROI		9.7%		
<u>Scenario 3</u> (F	uel prices 5%/	year near term,	10%/year lor	ng-term)
Net Cash Flow	I	2.1	1.1	16.0
ROI		2.7%		

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ROE ANALYSIS: Base Scenario

Operating Cash Flow	2.3	4.4	34.1	
Total Debt Service	-2.0	-1.6	-16.2	
Tax Saving (payment)*	.8	<u>-1.7</u>	- 5.7	
Net cash flow	1.1	1.1	12.2	
Debt coverage ratio** ROE (2/1 debt/equity ratio): ROE with syngas tax credit:		2.8	2.1 (Average)	

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*Does not include the annual syngas tax credit. **Operating cash flow divided by total debt service.

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To assure the practical viability of the project after demonstrating acceptable economics, key participants are required, namely-a coal supplier who can deliver coal at the price indicated, the supplier of a suitable parcal of land, an electric utility to buy power, a purchaser of the steam and/or electric power, an engineer/constructor who can provide the required engineering, various equipment suppliers, and an owner/ operator who will manage and guarantee the operating availability and performance of the plant. For the Scranton AAP site, some of the potential participants are:

- o Coal Supplier: Unionvale Coal Company; American Natural Resources.
- o Land Supplier: University of Scranton
- o Electric Utility: Pennsylvania Power & Light
- o Long Term Steam Purchaser: Scranton AAP.
- o Owner/Operator: Foster-Wheeler Corporation; American Natural Resources; King Smith

The expression of interest of the above participants at this stage confirms the potential of the GFC project, should its economics and financiability be born out in further design and testing work.

3.3 Fort Greely Ownership/Financing

The following assumptions were made for the Fort Greely financing analysis:

- o Private capital contribution of 20% of total required capital
- o Debt/equity ratio of 2/1.
- Debt repaid over 15 years with a constant principal repayment (decreasing total debt service payment).

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o Average interest rate over the life of the loan of 13%.

- o Current tax laws as follows:
 - 1. Ten percent investment tax credit.
 - 2. Five year depreciation.
 - 3. Fifty percent marginal tax rate.
 - Annual income tax credit for synthetic gas analyzed as an incremental benefit.*

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Each of the above financing assumptions are within the range typically used for analyzing the financing attractiveness of this type of energy project. Using the base scenario for energy prices discussed in paragraph 2.3, the ROE for Fort Greely was 33% which increases to 60% when considering the annual syngas tax credit.

Referring to Table 3-3, operating cash flow (revenues minus costs) is the same as for the ROI analysis. However, it was assumed that two-thirds of the private capital contribution would be debt with a maximum debt service payment of \$2 million in 1990. Given the interest cost, the taxable income is lower, and the tax savings are higher, than for the ROI analysis (no debt). But, because the equity invested is one-third of the private capital, the return of that cash flow on the equity is 33%.

Refer to Appendix A for details and annual cash flows.

*The annual income tax credit for nonconventional sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculations so that the resulting ROE can be compared to other ROEs reflecting conventional tax assumptions. From the debt lender's point of view, a suitable debt coverage ratio is provided. While the minimum debt coverage ratio of 1.5 is not met in the first three years, a coverage ratio of 1.5 - 3.5 is provided in the remaining years. The average debt coverage ratio for the first 10 years of plant life is 2.0, as shown in Table 3-3. Thus, the debt structure could be worked around and tailored to the cash flows of the project to provide an acceptable debt coverage ratio for the entire debt service life.

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CONTRACTOR NUMBER OF STREET

GFC PLANT ECONOMICS SUMMARY

FT. GREELY, ALASKA

Economic_Vari	able	1990	1995	10-Year Total (1990-1999
			<u> </u>	·····
Base Scenaric	<u>)</u>			
Revenues:	Electric	6.7	9.2	86.9
	Other	1.7	2.2	21.4
	Subtotal	8.4	11.4	109.3
Costs:	Fuel	3.2	4.1	40.2
	O&M & Other	_2.8	3.6	35.4
	Subtotal	6.0	7.7	75.6
Operating Cas	sh Flow	2.4	3.7	33.7
Tax Saving (F	Payment)*	.3	<u>-1.9</u>	- 9.5
Net cash flow	1	2.7	1.8	24.2
ROI		11.1%		
<u>Scenario 2</u>				
Net Cash Flow	٧	2.7	2.5	30.9
ROI		15.7%		
<u>Scenario 3</u>				
Net Cash Flow	i	2.2	1.8	23.9
ROI		9.9%		

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ROE ANALYSIS: Base Scenario

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Operating Cash Flow	2.4	3.7	33.7	
Total Debt Service	-2.1	-1.6	-16.9	
Tax Saving (payment)	<u>1.0</u>	<u>-1.4</u>	<u>- 4.6</u>	
Net cash flow	1.1	.7	12.2	
Debt coverage ratio ROE (2/1 debt/equity ratio): ROE with syngas tax credit:		2.2	2.0	

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To assure the practical viability of the project after demonstrating acceptable economics, key participants are required, namely-a coal supplier who can deliver coal at the price indicated, the supplier of a suitable parcal of land, an electric utility to buy power, a purchaser of the steam and/or electric power, an engineer/constructor who can provide the required engineering, various equipment suppliers, and an owner/ operator who will manage and guarantee the operating availability and performance of the plant. For the Ft Greely site, some of the potential participants are:

- o Land Supplier: Department of Army
- o Electric Utility Power Purchaser: Golden Valley Electric Association.
- o Coal Supply: Usibelli; Owen
- o Long Term Steam Purchaser: Department of Army
- o Owner/Operator: Foster-Wheeler; American Natural Resources; King-Smith; Owen.

The expression of interest of the above participants at this stage confirms the potential of the GFC project, should its economic be born out further design and testing work.

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4.0 CONCLUSION AND RECOMMENDATIONS

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This report has presented the analysis and findings for an economic and financing feasibility study of the Coal Gasification/Fuel Cell/ Cogeneration (GFC) project federal and private third party cost-sharing concept -- a concept designed to shift Army fuel use from oil or gas to coal and reduce energy costs in doing so. As a feasibility study, the intent was not to provide an optimal design or economic/financing structure, but to arrive at reasonable conclusions regarding the viability of the GFC cost-sharing concept. The third party would own, finance, construct and operate the facility under a long term contract with the Army.

Overall, the GFC concept appears economically feasible. Two of the three Army bases evaluated provide the conditions for an economically viable GFC plant, with potential benefits for a number of Army bases. Specifically, the GFC concept was found to be economically viable for the Scranton Army Ammunition Plant (AAP) and Fort Greely, Alaska, but not for Fort Hood, Texas or for the baseline site, Washington, D.C.

Beyond the direct cost savings that could be provided by a GFC plant at an Army base, there are other indirect benefits that would accrue to GFC plants as well. The site-specific conclusions, general GFC plant conclusions, conclusions regarding broader benefits from GFC plants, and the recommendations based on these conclusions are presented in the four sections below.

4.1 Site-Specific Conclusions

Capital costs referred to in this paragraph are referenced to the date, 1/1/90.

The SCRANTON ARMY AMMUNITION PLANT site was found to be economically feasible and financable for a GFC plant application. This conclusion is the result of the following economic findings:

o Total capital requirement of \$51 million.

o Federal capital contribution of \$36 million (70%).

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- Private capital contribution of \$15 million (30%).

- o Ten-year site savings (1990-1999) of \$7-11 million
- Basic economics and financing characteristics that would provide the GFC third party owner with a 25-30% or higher return on equity

FORT GREELY, ALASKA was found to be economically viable for a GFC plant application. This conclusion was based on the following economic findings:

- o Total capital requirement of \$81 million which includes significant additional construction costs required for an Alaskan Army base location
- o Federal capital contribution of \$65 million (80%)
- o Private capital contribution of \$16 million(20%)
- o Ten year site savings (1990-1999) of \$10-20 million
- o Economic and financing characteristics providing the GFC third party owner with a 30-35% or higher return on equity.

FORT HOOD, TEXAS was found not to be economically feasible for a GFC plant application, based on the following findings:

- o Total capital requirement of \$51 million
- o Federal capital contribution of \$36 million (70%)
- o Private capital contribution of \$15 million (30%)
- A negative return on total investment for the GFC plant under any reasonable level of site savings, even with an 80% federal and 20% private capital contribution

The GEORGETOWN UNIVERSITY, WASHINGTON, D.C. site was found not to be economically feasible for a GFC plant application, based on the following findings:

- o Plant capital requirement of \$63 million which includes significant special construction costs due to site constraints
- o Federal capital contribution of \$44 million (70%)
- o Private capital contribution of \$19 million (30%)
- A low or negative return on total investment for the GFC plant under any reasonable level of site savings

4.2 General Conclusions

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The key to achieving a suitable return on total investment or on the private equity required for a GFC project is the operating cash flow available for debt service and for the plant owner. Below, the conclusions on the factors affecting operating cash flow are summarized.

The potential to lower the O&M costs below the estimated \$2.0-2.5 million range is believed to be limited, since these costs are based on well understood and historically confirmed labor and material requirements. Delivered coal prices were received from suppliers and are considered a reliable basis for this analysis.

Analysis of the revenues shows that the electric power revenues dominate the cash flow, comprising 80-95% of the total depending on the site. Revenues from steam and the sale of other products (e.g., tars/oils or coal fines) help, but their total impact is limited. However, with the sale of steam there is a leveraged effect on the Army base energy-related O&M costs. The ability of the base to shut down its on-site boilers, if enough steam is supplied, can result in a significant reduction in labor and related boiler and steam system maintenance and materials expenses. Therefore, at the margin, a configuration that provides more steam and less electricity from the GFC plant is better for the site. (However,

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depending on the relative price for electricity versus steam, it may not be more advantageous to the economics of the GFC plant itself.)

The price paid by the electric utility for power from privately-owned power plants will be key to the GFC plant economics at many Army bases, either because the GFC plant must sell part of its power to the utility, or the utility may offer higher prices than the cost of purchased power to the Army base. The reason the utility's price can be higher than the Army base's purchased power rate is that the utility price is based on its marginal and most expensive cost of power, whereas the Army base purchased power rate reflects an average utility system cost.

The areas where utility purchased power costs (termed avoided costs under the law) are likely to be highest are electric utility service areas where substantial new capacity will be needed in the early to mid '90s. After a decade (1980s) of likely limited additions of utility capacity, most electric power demand forecasters believe that substantial new capacity will be needed throughout the United States during the 1990s.

In terms of absolute rates, a GFC plant application would make economic sense in utility areas where the current purchased power or avoided cost rate is at least 6c/Kwh with escalation expected to be the same as inflation over the medium to long term. Alternatively, if the current electric power rate is lower, but the escalation rate is 2-3 percent above inflation, the GFC economics would still be viable.

Since forecasted electric power and fossil fuel prices have been so uncertain over the past 15 years, and significant long-term uncertainty will continue, a careful look at the economic conditions that would strengthen or weaken the GFC plant economics is useful.

Factors That Would Strengthen GFC Plant Economics. The following trends would strengthen the GFC plant economics if they occurred:

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- Lower coal price escalation than electric power price escalation (All scenarios analyzed assumed the same longterm escalation rate, although the absolute rate itself was varied from five to 10 percent).
- o For Army bases that use significant amounts of oil or gas, higher oil and natural gas escalation rates than zero percent per year in the near term and five percent per year in the long term.
- o Special, long-term coal contracts at lower than open market prices, guaranteed by the government. (These would be easy to sell off if the Army base closed, since the price is lower than the open market.)
- o Optimization of GFC plant design efficiency.
- Retention of the synthetic gas annual income tax credit through 1999 (currently available but not assumed in the basic economic analysis).

Factors That Would Weaken GFC Plant Economics.

- o Higher coal price excalation than electric power price escalation.
- Lower oil and natural gas escalation rate than zero percent per year in the near term and five percent per year in the long term.
- o Degradation in the GFC plant operating efficiency and availability.
- o Inability to lower the GFC plant capital cost by 50% by the early '90s, and by a total of 70% by the mid '90s. (Regardless of the judgement about this factor, the GFC economic concept is not necessarily weakened for other coal-using technologies).
- o Elimination of the 10% investment tax credit.

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It is believed that the factors likely to strengthen GFC plant economics are more likely to occur than those that would weaken the economics. Few experts believe that the long-term coal price escalation will be as high as electric power price escalation, and few believe that the 20-25 year time horizon for oil and natural gas prices would see a lower price than the zero percent and five percent escalation rates assumed under the base scenario analysis.

With further optimizing, the efficiency of the GFC plant should be improved, reducing coal costs. Also, the fuel cell and other equipment manufacturers will have invested tens of millions of dollars into the technology components of the GFC plant on the basis of a market requiring capital costs of one-third or less than the prototype capital costs (same year dollars).

It therefore, seems reasonable to conclude that these factors in combination will improve GFC plant economics.

4.3 Indirect Benefits

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Indirect benefits which do not affect Owner/Operator or Army costs are as follows:

- 1. The Army would be able to concentrate its resources more on Army activities, and less on site utilities -- i.e., apply the personnel more to the main mission of each base. Further, the security of energy supply would be increased over the existing electric and fuel power supply.
- 2. The nation would benefit from a shift to coal from oil or natural gas, improving national energy security as well as making a positive contribution to the national balance of payments. Further, there would be technology-related benefits to the nation from the development of the gasification and fuel cell technology.

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- 3. This is a key opportunity for the Army to commercialize effectively a more efficient, near term, coal fired, environmentally sound technology. This flexible technology produces electricity, heat and steam (water) directly.

- 4. The coal industry would benefit from an additional market for its coal. It would also benefit indirectly through the coal-using technology development supported by the GFC program.
- The electric utilities involved would benefit in several ways. 5. First, an electric utility can be a partial third party owner. The utility would also have a reduced need for new plant construction with attendant capital savings, and power prurchased at a price no higher than the costs they avoid. The GFC plant would also improve electric system reliability and reduce utility line losses, compared to the development of the same capacity at one central station location. This would be of particular benefit at those Army bases located in relatively remote areas. Finally, the development of small power plants on a utility system would help the public image of the utility in each of the localities where the GFC plant is situated could develop.
- 6. As a result of the plant construction and operation, as well as the related coal activities, there would be a number of economic benefits for each of the communities and surrounding areas for each GFC plant location.
 - a. There would be 34 direct employees of the plant.
 - b. The number of additional jobs created by the economic activity could approximately 25-35 jobs, in accordance with commonly accepted economic multipliers.

The additional jobs would occur not only through supplier activities (e.g., coal transportation and coal mining), but also more indirectly through additional retail purchases by the employees of the plant and the plant entity itself. And, if properly implemented by the private owner entity, there could be special training and educational benefits provided by this new technology energy plant to the primary and secondary educational institutions in the area.

4.4 Recommendation

On the basis of positive economic feasibility results for two of three Army bases, and the broader benefits that can accrue to GFC plant development, it is recommended that the Department of the Army proceed to the next stage of development for Scranton AAP and Fort Greely. More specifically, it is recommended that the Department of the Army initiate funding for:

- 1. Preliminary design and initial optimization studies.
- 2. Refined economic analysis including comparison with alternative energy systems.
- 3. Selective testing of alternative coals with gasifier technology options.
- 4. Initial ownership discussions and conceptual negotiations on the cost-sharing participation with potential owners.
- 5. Identification of total number of Army bases that would satisfy GFC viability criteria.

5.0 APPENDICES

A. Cash Flow Analyses

- 1. Georgetown University Site Analysis without GFC Plant
- 2. Georgetown University GFC Plant Analysis
- 3. Scranton AAP Site Analysis without GFC Plant
- 4. Scranton AAP GFC Plant Analysis Westinghouse Fuel Cell
- 5. Scranton AAP GFC Plant Analysis UTC Fuel Cell
- 6. Fort Greely Site Analysis without GFC Plant
- 7. Fort Greely GFC Plant Analysis Westinghouse Fuel Cell
- 8. Fort Greely GFC Plant Analysis UTC Fuel Cell
- 9. Fort Hood Site Analysis without GFC Plant
- 10. Fort Hood GFC Plant Analysis

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	<u>6</u>	19R5 Cest	5.59 0.60	4,12	ù.63	froe belc 62.76	13000	2.41 4.00 N.A.			73.90	50.60 23,30	3.30 4.33 2.78	12.63	5.77 8.74	262.00 118.00 680.00
ř	D PENEFITS & C 240 psia: y Sain in Rt		furch El Fwr Cost (c/lwh) 6fE Elsc En Fr /cts/lwh) Electric Pemand(s/lw/He)	(104/1)	(le		ゆきゃっと	Cnal Frice(1/Mil.Btu) Steam Pr \$ Esc Rate(2/yr) O & M Esc Rate(2 per Yr)	ER DC VI GFC DC	Hil twhs) to	Subtotal	l 5/kwh) -peat :ermediate :.peat	Brade	ad MM Distribution(12-Mo Fat) Frod/Transm(4-Mo Avg) ad MM Rate(6:4w Mn)	n(12 Mg5) ((1 Mg5)	(Ha) [bs) 4.) ctal ïear
	SITE COSTS AN Steam Putput: Thou lbs/hr Not Enthalp		furch El Fwr Gff Elsc En ⊥ Electric Pea	Natural Basis/acf)	Fiel Dil(\$/gal)	Existing Cogen Coal Price(\$/Ton)	Eaal Heat Content (Btu/16)	[na] Frice(\$/Mil.8tu) Steae Fr \$ Esc Rate(2/yr O & M Esc Rate(7 per Yr)	ELECTRIC FONER Demand Withmus GFC	- FMM Gacunt (Mil Fwhs) Cn-pest Intermediate Nff-pest		Caepus Moopital HWH Rates ((ts/hum) Average On-peat Average off-peat A-orace off-peat	(),erall Average S:reer(\$ Mcs) Kect of Year	Feat MM Distribution(12-Mo Fat Fred/Transm(4-Mn Avg) Frat MM Rate(6/14 Mm)	Erstribution(12 Mgs) Frgd/Transm(1 Mas)	THE FRAL DE MANN Frege Deensdith) [he) Summer 14 M-) Frest of Yr T-tal Tran

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Feak Deminion Lbs/Hrl	120.00	Annual	120.00	122.00	130,00	137.00	143.00	145.00	3.00	149.35	153.83	158.45	163.20	168.09	173.14	178.33	183.68	189.19	
Avg Rtu/Lb/Het) Ril Atus Required	1050 714,00		1050 635.25	10°201 967.01	1050 700.36	1050 735.38	1050 772.15	1050 810.76		1050 835.08	1050 860.13	1050 885.94	1050 912.52	1650	1050 968.09	1050 997.13 1	1050 1027.04 1	1050 1057.86	9,254.43
Hot Nater (Ni) Gals)	0°°0		0.00	0.00	00°0	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Arg Rtu/Gal Ril Ftus Required	0.00		0.00 0.00	0.00 0.00	0.00	0.00	0.00	0.00 0.00		0.00 0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ETISTIME COSEMERATION Elect Emergy (Mii Juhe) Sammer Rest of Yr	0.00 0.00	(Input) (Input)	4.28 5.32	4.28 5.32	4. 28 5. 32	4, 28 5, 32	4.28 5.32	4.28 5.32		4, 28 5, 32	4.28 5.32	4.28 5.32	4. 28 5. 32	4. 28 5. 32	4, 28 5, 32	4.28 5.32	Fa 4.28 5.32	Fage 3 4.28 5.32	42.82 53.18
Subtotal	ÛŮ U		9.60	9.60	9.60	9.60	9.60	9.60	1	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	96.00
Mın Annual MM Qutput Avg Mın Suamer MM Qutpt	0.00	(Input) (Input)	1.15 1.15	1.15	1.15	1.15	1.15 1.15	1.15 1.15		1.15	1.15 1.15	1.15	1.15 1.15	1.15	1.15	1.15	1.15	1.15	
Steam Supply(Mil Lbs) Summer Fest of Yr	0.00 0.00	0.00 (input) 0.00 (input)	250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00		250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00	250.00 350.00	250.00	250.00	250.00 350.00	2,500.00 3,500.00
- Subtotal Arg Rtw:(biMet) Stear Btus(Bils)	0.00 0.00 0.00		600.00 1050 670.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	•	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	600.00 1050 630.00	6,000.00 6,300.00
TG Heat Rate Poiler Efficiency Coal Rtus Required(Ril)	0.00 0.70 0.00	(input) (input)	3700 0.70 901.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.79 900.04		3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 0.70 900.04	3700 9.70 900.04	3700 0.70 900.04	3700 0.70 900.04	9,000.36
(USTS-Elect Energy(Mil) Dn-peak Intermed Off-peak																			
- Subtation (Net of Cogen) (OSIS-Elect Demand(#Mil) Distribution(Net) Frad/Transa(Net)	2.46 0.81		2.46 0.77 0.47	3.06	3. 74	4.28 1.10	4.86 1.22 0.44	5.40 1.36 0.78	•	5.85 1.47	6.34 1.59	6.87 1.73 0.94	7.45	8.08 2.03	8.75 2.20	9.49 2.38 1 to	10.28 2.58	2.79	79.64 19.99 10.00
(uabo	1.25		1.20	1	1.47	1.1	1.89	2.09	ı	2.27	2.46	2.67	2.89	3.15	3.39	3.68	3.98	1.1	30.87
	3.68		3.65	4.31	5.21	5.59	6.75	7.49	11	8,12	8.80	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
SITE FUEL FEDS & COSTS Mithinut efc																			
Existing Cogen Coal Regs Rtus Required(Rils) Rturlh	0.00 1.000		90.04 10100	500,04 1 1000	40°006	900, 04	900,04	\$00.04		900.04	900.04 11000	900.04	900.04	00.04 10001		900.04	90.04	900.04	9,000.36
lotal fonstu∩i) t/Ten faal t/Ten L∎eetone	51.00 9.12	9.0 0.0	34.62 51.00	51.00 51.00	51.90	51.00 51.00	34.62 51.00 9.31	51.00 9.31	5.00	53.55 9.78	34.62 56.23 10.27	13000 34.62 59.04 10.78	34.62 61.99 61.32		134.62 54.62 68.34 12.48			14.45 14.45	346.17
t/Ton-4sh Feagual Total t/Ton	2.45 62.76		2.45 62.76	2.45	2.45 62.76	2.45	2.45	2.45	5.00	2.57	2.7a 69.20	2.84	85.2		3, 29 84, 11	3. 45 88. 32	3.62	1.80	

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6.90 0.0 0.00

******** 2,994.43 4,277.76 1,553.40 2,677.76 1,600.00 31.32 ^^ 1 V 427.86 0.70 611.72 3.37 9.00 9.00 9.00 9.00 9.00 9.00 160.00 1030 155.34 6.39 6.21 451.22 6.30 3.01 0.98 6.52 0.00 99.0 2.94 3.37 0.0 0.99 2.94 7.30 2.85 3.86 ē. 67.21 6.30 2.71 0.93 6.21 597.04 0.70 567.21 160.00 1030 155.34 6.09 5.3 0.0 2.53 0.00 3.21 5.91 3.21 0.95 2.53 6.69 0.96 2.72 3.68 ; 364.47 6.30 2.43 0.89 5.91 367.13 0.70 524.47 3°09 0.00 0.0 160.00 1030 155.34 5.80 5.63 0.40 2.15 3.06 0.00 2.15 0.90 0.91 2.59 1.50 ð. 11 ÷ 338.09 0.70 482.98 1030 1030 155.34 5.52 322.98 2.15 0.84 0.0 0.96 1.82 0.0 2. N 2.91 6.30 2.91 0.86 1.82 -----5.59 0.87 2.47 309.89 0.70 442.70 0.00 0.00 0.00 0.00 0.00 0.00 2.77 0.00 160.00 155.34 5.26 5.11 282.70 6.30 1.88 0.80 5.36 2.35 1.18 0.82 2.17 0.00 0.82 1**8**.0 1.52 1.52 5.11 243.59 6.30 1.62 0.77 5.11 282.52 0.70 403.59 2.64 0.00 0. 0.0 160.00 1930 55.34 5.01 0.78 0.00 0.78 2.64 2 0.79 2.24 0 1.24 4.66 255.94 0.70 365.62 169.00 1930 155.34 4.77 4.63 205.62 6.30 1.37 0.73 4.86 2.52 0.00 2.52 0.0 12222 a. 75 1.00 0.74 8°.1 11 88 0.74 4.25 230. 13 0.70 328.76 0.00 0.00 0.00 0.00 0.00 0.00 2.40 **60.00** 1030 55.34 68.76 6.30 2.75 0.0 o. 8 0.78 2.40 0.00 0.78 (r. 72 2. n] 1.54 0.69 1.63 0.71 3.88 0.31 3 832.97 6.30 0.89 0.66 4.41 205.08 0.70 292.97 160.00 1030 155.34 4.33 10000 2.28 9.0 9.61 0.59 2.28 0.00 0.67 0.59 0.68 1.93 5.5 2.61 5.8 5.8 5.90 5. (j) 0.00 0.00 0.00 0.00 0.00 0.00 0.00 180.76 0.70 258.23 160.00 1030 4.12 4.00 98.23 6.30 0.65 4.20 1.7.1 2.17 0.00 0.41 2.17 0.00 0.64 0.41 0.65 1.8 1.1 **3**.6 142.15 0.70 203.07 43.07 6.30 0.29 2.99 0.00 0. 160.00 1030 155.34 1.... 2.17 1.12 0.63 0.18 2.17 0.00 0.18 1.49 1.73 0.0 8.4 19.0 0.64 20.00 6.30 0.13 0.63 4.20 105.38 0.70 150.54 6.00 0.00 0.00 0.00 0.00 0.00 0.00 130.54 1030 126.74 4.12 4.12 2.41 2.17 o. 9 0.52 0.08 2.17 0.0 0.52 0,08 7.9 5.0 1.71 11 70.36 0.70 100.52 0.0 0.0 0.0 0.0 2.4 20.00 6.30 0.63 2.58 2.15 2.41 2.17 0.00 0.0 00.0 0.00 0.52 1030 1030 0.32 0.13 0.68 2.17 0. B 0.32 0.08 6.9 1.45 2.41 2.17 37.01 0.70 52.88 0.00 3000 0.00 0.00 0.00 0.00 0.00 0.00 \$2.88 1030 51.92 2.3 0.13 20.00 6.30 0.13 0.63 80.0 2.17 0.00 <u>.</u>... 5.0 1000 7. 14 **.** 1.55 l. ?} 0.00 0.00 0.00 0.00 0.00 0.00 0.00 5.25 0.70 7.50 7.50 0.00 0.50 0.61 0.63 2.41 2.17 0.00 0.03 0.00 2.17 0.00 0.03 9 н (1.1.1.1 2.20 . . 5 (Input) (Input) (Input) (Input) 0.01 0.00 2.44 0.70 298.66 13000 11.49 51.00 9.31 2.45 62.76 6.30 6.30 3.16 9.77 5.15 2.41 0.00 714.00 2.41 0.72 7.33 7.12 6.39 6.20 0.05 1.1 0. u 0.72 0.05 9. e 1.10 1.50 Supalemental fixel Keqs Suppl Steam Rtus(Ril) 7 Site Briler Effics (cyen Coal Cost(thil) Suppl Fuel Rtus(Bil) Unn Aff Ease 0 * M riMi Coal (Same cogen builer) Ftus Required(Bil) Rtus Reguired(Ril) ktus Pequired(Pil) TOTAL FUEL COST(\$M1]) Man-GFC Cogen Coal 4 \$/fon-Limestone \$/fon-Ash Removal Total (Mil Cu Ft) Suppl Steam Fuels Man-Gfi (ngen D t M [0001 500] Coal Cost (Mil) Intal Sals(Mil) Lippl Thermal D L intal Fuel Cost Subbreal 0 to # Oil Cost (Mil) Fac Cost (#M1) Btu/Pb1 (Mil) 8tu/Cubic Ft \$/1on Trial Tonsti) \$/Ton-Coal Mil Etus s/McF s/Mil Rtu Mil Ru Will Btu Ptu/Lb Natural Gac [eaj Total [f] 6.35 Ξ Fuel Cil

17.85

14.98

27.33

0.09 8.05

8.05

23.14

8.18

14.98 50.36 an accorde to accorde accorde to accorde to accorde to accorde to accorde to accorde to accorde to accorde to a

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TOTAL NON-GEC LASE COSTS																	+
furch Elect Fow≏r	3,68	3.65	4.31	5.21	65.0	6.75	7.49	9 .12	8.90	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
لأفدته ليبواج	12.2	2.70	2. 19	1.58	2.78	2.99	3.23	3.54	3.89	4.26	4.66	5.11	5.59	6.11	6.68	7.30	50.36
U * 1	1.50	1,94	1.59	2.15	2.26	2.37	2.49	2.61	2.75	2.88	3.03	3.18	11.34	3.50	3,68	3.86	31.32
latal Costs	65 80	ú8*2	8.69	9.94	11.02	12.11	13, 20	14.27	15.43	15.68	16.03	19.49	21.07	22.78	24.62	26.62	192.19
ENERGA EDELS MITH GFC																	
GFE Availability'Hrs/ Yr)							9601	4601	7096	9607	9501	1596	9651	1296	1596	7546	
EfC 14hs Furchased(M1)							76.95	76.95	76.95	16.95	76.95	82.37	82.37	82.37	82.37	82.37	796.60
Frice (c/bWh)		Ξ.	(Cost of purchased electric energy)	rchased el	lectric en	ier gy)	6.66	7,00	7.34	1.71	B.10	8.50	8.93	9.37	9.84	10.33	
Min (FC Anrual MW (lutput FC Ava Min Swarer MW							10.84 < Input 10.84 (Input	10,84 10,84	10.84 10.84	10.84	10.84 10.84	10.84 10.84	10.84 10.84	10.84 10.84	10.84 10.84	10.84 10.84	
Total Elect Contentil)						ļ	5.13	5, 38	5.65	5.93	6 .23	7.90	7.35	1.12	8 .10	6.51	67.01
6fC Steae Furch (Mil 16s) 6fC Steae Rtus (Rit) Frice (S/MMi Lbs)							14.19 14.90 5.11 5.00	14, 19 14, 90 5, 36	14.19 14.90 5.63	14.19 14.90 5.91	14.19 14.90 6.21	14.19 14.90 6.52	14.19 14.90 6.84	14.19 14.90 7.18	14.19 14.90 7.54	14.19 14.90 7.92	141.92 149.02
Hnt Water Furch(Mil gals)							0.00										
Frise (c/ Bal)							0.00										
Total Timen Cocts(\$M1])						!			0.06	0.08	0.09	0.(19	0.10	0.10	0.11	0.11	0.91
Subtatal BFF Fa Casts						ľ	5.20	5.46	5.73	6.02	6. 32	1.09	7.45	1.82	8.21	8.62	67.92
Existing Ergen Fuel Crats							2.17	2.28	2.40	2.52	2.61	7.77	16.5	3.06	3.21	3.37	27.33
Singeterential Energy Fields																	
Flort facergy/Mulf Ember Cate ar AMA							35.45 4 00	39.11 5 00	42.88 \$ 20	46.76 5 54	50.76	49.46 4.13	53.70 4.43	58.07 4.75	62.57 7 AB	67.21 7 45	505.99
Energy Cost (ENL)							1.70	1.97	2.27	2.60	2.96	3.03	3.45	3.92		2.00	31.35
Elent Desend Annou (MW) national States							3.91	4.39	88.4	5.38	5.91	9.44	7.00	1.56	8.15 1. 1.	8.76 11.00	
Start Darand Scaac (MA)							3.91	8. 4	1.87	8. <u>1</u> 8	5.90	ę. 4	6.99	7.56	8.15 8	8.75	
Fate(\$/14,4p)-4 Ha [baard] [ng)(\$H]]]							12.51 0.55	13.13 0.65	13, 79 0, 76	14,46 0.88	15.20 1.02	15.96	16.76 1.33	17.60 1.51	18, 48 1. 71	19.40 1.93	11.52
51466 Ever 18411						:	2.26	2.62	3.03	3.48	3.98	4.20	4.78	5.43	6.15	6. 93	42.87
Suppl Steve (M) [[bc] Hit Water (M) [fa]s)							150.78 0.00	172.89 0.00	195.66	219.12	243.29 0.00	268.17 0.00	273.81	320.21 3	347.40	375.41 0.00	2,586.74 0.00
Theraal Rtue (Pij)							165.86	190,18	215.23	10.145	267.61						2,845.41

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Mon-646 Fuel Regs Revs Reg (Ril) Coal (MA) Tons) Frice (RTOn) Cost (MH) Cost (MH) Revs Reg (Ril) Frice (RTMc) Cost (MH) Free Oil (MH) Eals)												
Rtus Req (Rt1) Coal 1000 Tens) Frice 15/Ten) Cast 18/11) Cast 18/11) Rtus Req 1811) Frice 11/16(1) Gost 11/11 Frus Req (Rt1) Frus Req (Rt1)												
Coal (ANO Tens) Frice 14:Ten) Caet (Mil) Phus Req (Ri) Mat 6as (Mil Cu Ft) Frice 11/Me() Cost (TML) Frus Req (Ri) Frus Req (Ri)	0°00		0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0 0	0 0
rrce 12.100 Cost (MLI) Rhus Req (BLI) Frice 11/Mc() Cost (MLI) Frus Req (RLI) Frus Req (RLI)	0.00		0.00	0.00	0,00	0.00	00°0	0.00	0.00	0.0	0.00	0.00
Plus Req (Prl) Mat 6:s (Mrl Cu Fl) Frice (1/Mrl) Cost (Mrl) Frus Req (Prl) Fred Dil (Mrl Eals)	62.76 0.01		65.50 U.00	6 9.20 0.00	72.66	76.29	80.10 0.10	84.11 0 00	88.32 0.00	92.73	97.37	v 0 v
rus med kuit Mat 6-s (Mil Cu Ft) Firce HJ/Art) Cost (Mil) Fiys Reg (Riti Fiyel Dii (Mil 5als)										~~~	A	5
Frice (S/REF) Frice (S/REF) Gost (MFL) Prus Req (REF) Free Oli (MFL Gals)	160.00		160.00		160.00	00.091	160.00	160.00	160.00	160.00	160.00	1,660.00
Cost (MHL) Cost (MHL) Prus Req (Rel) Fyel Oli (MHL Gals)							155.31	155.34	155.34	155.34	155.34	1,555.40
ftus Reg (fil) fuel Oil (Mil Gals)	0.64			0.71	2.0	10.c	0.82 0.82	7C.C	5.80 0.90	6.09 0.95	6.39 0.99	8.05
Fiel Oil (Mil Gale)	:			:								5
	76.94		111.68 1	147.47		222.31	261.41	301.69	343, IB	385.92	429.93	2,464.88
frice (f.5al)	16.0			84.0				10.2	2.29	2.57	2.87	16.43
[act '9Mi])	0.37		(. 4 9	0.68	0.00	1.13	0 9 -1	1.70	2.03	2.39	0. YB 2. B0	13, 85
Suppl Fuel foettekij)	0.96		1.16	1.39	1.64	1.91	2.22	2.56	7.93	1.M	1.79	00 12
0 k M [ost (\$n;1)												
Eristing Coyon Flart	0.65		0.68	0.72	0.75	0.79	0.83	0.87	0.91	0.96	1.01	9
Suppl Therm Flant	- 84 -		1.93	1.01	11.6	1 74	7 75		93 6	2		
	•	5.00	:		-			5	17.7	71.7	C9.7	1.0
	0.50	Esc Rate	0.53	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	6.29
Suppl D t M Cast	1.99	1	2.09	2.19	2.30	7.42	2.54	2.67	2.80	2.94	3.09	25.03
COST/REFETT SUMMARY												
Mitheut AGC Facility												
furch Elect Fwr	7.49		8.12	8.80	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
ſyrch fuels	3.23		3.54	3.88	4.26	1.66	5.11	5.19	6.11	6.68	7.30	50.36
N 1 2	2.49		2.61	2.75	2.88	3.03	3.18		3.50	1.68	3.86	W.W
Subtotal-Mn (Ff	13.20	ł	14.27	15.43	1	18.03	19.49	21.07	22.78	24.62	26.62	192.19
With Gff Facility												
Durch Gél Éjs.t fwr	5.13		5. 38	5.65	5.93	6.23	7.00	7. 35	1.72	8.10	8.51	67.01
لاستدب ولزل إيادتهما	10.0		₿∪°Ŭ	0.0B	90°0	0.09	0.09	0.10	0.10	0.11	n.n	15.0
te tet tet	5.20		5.46	5.73	4. ñ2	6.32	1,05	7.45	7.82	8.21	8.62	67.92
فالتقارب والمعارفية	<u></u>		2.28	5.6	2.52	19.2	11.5	2.91	3. II 6		1.17	27.35

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	Λ,ι-ζ.	42.87	21.90	64.77	25.01	157.73	7.14		
		6.93	3.79	10.73	3.09	25.81	0.81		
		6.15	3.34	9.49	2.94	23.85	0.77		
		5.43	2.93	8.36	2.80	22.04	0.74 0.77 8.56 8.99		
		9 , 78	2.56	7.34	2.67	20.37	0.67 0.70 7.76 8.15		
		4.20	2.22	6.41	2.54		0.67 7.76		
t		85.8	1.91	5.89	2.42	•	0.76 7.09		
1000 H		3.48	1.64	5.12	2.30	15.96	0.72 6.74		
		 1.03	1.33	4.42	2.19	14.74	0.69 6.42		
		2.62	1.16	3.79	2.09	13.62 14.74 15.96	0.65 6.11	1990 NFV at Discount Rate of 20.00 2	2.50
56									
		2.26	96.0	3.22	1.99	12.58	0.62 5.82	Cueul ative Savings	rs 7.14
24.4									10-Years
								SAV [NGS:	
772.								FINANCIAL EVALUATION OF SAVINGS:	
1.2								F I NANC I AL	
Ĩ)				NITH GFC	(LHL)) GFC		
		Suppl Elect Fur	Suppl Fuels	Subtotal	μ a ŋ	^c ubtotal-With GFC	NFT FFC SAVENDS / MALE		
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ƙated Output rHW1: A⇒ailiHrs per Yri:		2000	i úSul	11.60	2.54 MM 0.89 (0.60) MM	(3°26) WN	10.84	38.68 0.00	1.3		25.20				+ Tars/011s 38.68		Gross Heat Rate:	145.76 (fail Armie
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Site: DC August 19, 1985										l Tower				Hourly Calc	Net Fwr Out + Steam 17.01 2.10		17,441.53	Divided by
	ENERGY PALANEE SUMMARY	Stera Output: Thou Ibs∕hr € 240 psia:	Wet Enthalpy Gain:	Electric Fwr Output: Fvel Cell Output	Gas Expander Output Thermal Mgt System Fower Conditioner Eoses	âux Fur Regs	Met Fwr Cui	Other Outputs: Tars/Oils Other/e.g., Sul,Ameon)	Losses Ash C	uputure caroon push Heat Rejected by Cooling Tower	CO Shift Arr Cooler HSFS Stack Loss	Al scel l aneous	101al 81455	GFC FLANT EFFICIENCL: H			Hot Hoat Fato:	(Enal minye Ctear 5 (arg)

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EEDMORIC & FINANCIAL Assumptions	Jul. Ju All foruts	All formuts		All Tonute	DANERSHIP AND FINANCING SIRUCIURE			
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6ff Elert fn fr litsitwh)	1 5.22	5.00	6.66	5.00	Fercent Government Funding		Input	
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[agl Frica(\$/Ton)	62.00	0.00	62.00	5.00	Interest rate Loan term(years)			<input Input</input
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GEC O 6 M COST Rreadonnian(1)		Direct Labor	Fringes & 202 Contract Oper Fee	Contract Maint.	Chee & Supplies	Spare Fts/Maint Sup	Water & Site Utils	Ash/Sludge Disp.	Hi sce]	Subtotal	Wheeling Charge	Fuel Cell Reloading Costs in 1985t of		101AL B & M		======DTHER ANNUAL EXPENSES Legal/Account.	Insurance Frop. Taxes		IUIAL UINER				
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$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Electric	00 ° 0	0 0 0	00.0		5.13	5.38	5.65	5.93	6.23	7.00	7.35	7.72	8.11	8.51	67.03		8.94
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$ \begin{array}{cccccccccccccccccccccccccccccccccccc$			0°.0	00.0		1.15	1.21	1.27	1.33	1.40	1.47	1.54	1.62	1.70	1.79	14.50		1.88
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$			0.00	00°U		61.15	6.67	1.00	7.35	1.72	8.57	9.00	9.45	9.93	10.42	82.47	•	10.94
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$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21		0.42
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	Subtotal	0.00	0.0u	0.00	ı	5.97	6.27	6.5B	6.91	1.26	8.23	B.64	9.07	9.52	10.00	78.46	ı	10.50
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	OFERATING CASH FLOW	0,00	0.00	0, 0		0.38	0.40	0.42	0.44	0.46	0.35	0.36	0.38	0.40	0.42	4.02		0.44
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Cebt Service: Principal Interest	0.00 1		00.0	15 Yrs	0.85 1.65	0.85 1.54	0.85	0.85 1.32	0.85 1.21	0.85	0.85 0.99	0.85 0.88	0.85	0.85 0.66	8.48 11.58		0.85
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Subtotal Coverage Ratio	(Lanst 0.00		interest) A.AA	•	2.50	2.39 0.17	2.28 0.18	2.17 0.20	2.06	1.95 0.18	1.84 0.20	1.73 0.22	1.62 0.25	1.51 0.28	20.06 0.20		1.40 0.32
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Dabt Svi Rosarke [wew] Rosprve					0.00	0.00	0.00	0.00	0.00 0.00	0.00 0.00	0.00 0.00	0.00 0.00	0.00	0.00 0.00	0.00 M.A.		0.00
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	RESIDUAL CASH FLOW	0.40	0.00	0.00		(2.12)	(1.99)	(1.86)	(1.73)	(1.60)	(1.60)	(1.48)	(1.35)	(1.22)	(1.09)	(16.04)		(0,96)
If relate a fequipeent) 3.37 0.00 0.	adj luakatrutu					0.00	00.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
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1.10 30.00 6.00 0.00 </td <td>Pape 5-ve Equip(SL) at</td> <td>56.0</td> <td></td> <td>Fercent)</td> <td></td> <td>3.37</td> <td>3.37</td> <td>3.37</td> <td>3.37</td> <td>3.37</td> <td>:</td> <td>:</td> <td>:</td> <td>:</td> <td>:</td> <td>16.83</td> <td></td> <td>:</td>	Pape 5-ve Equip(SL) at	56.0		Fercent)		3.37	3.37	3.37	3.37	3.37	:	:	:	:	:	16.83		:
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70.00 Fercent) 1.81 0.00 fr.Wil Rtu to 1979 0.00 0.00 0.00 0.00 0.00 0.00 11.73 11.73 11.73 11.21 11.73 11.21 11.73 0.00 0.01 0.33 0.35 0.36 0.46 11.23 11.73 0.00 0.01 1.21 0.35 0.35 0.35 0.36 0.47 0.01 1.11 1.21 0.20 0.35 0.35 0.36 11.23 11.61 0.01 0.01 1.26 0.35 0.35 0.36 11.28 11.74 18.71 0.01 0.01 1.28 0.36 13.28 13.282 14.05 10.73 18.71 0.01 0.01 13.28 13.282 14.05 13.24 18.71 0.01 0.01 13.28 13.282 14.33 17.34 18.71 0.01 1.140 13.28 13.282 14.33 13.73 18.71 0.01 1.140 13.67 13.68 17.282 14.33 11.73 18.71	tav Caulog or Faymont(-)	0.00	0.00	00°0		2.32	2.26	2.19	2.12	2.05	0.38	0.31	0.25	0.18	0.12	12.19		0.05
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ν.νο Δ.Δου (4.46) (4.26) (4.00) (3.67) (3.28) (2.82) (4.05) (5.21) (6.31) (7.34) (8.31) KIE= EKR Percent; NYY= EKR at a ERR Percent Disc Rate. Using a E0 Year Cash Stream			UU.O		(4.46)	0.20	ń.26	0.33	0.39	0.46	(1.23)	(1.16)	(01.10)	(1.03)	(0.97)	(06.0)	(184)	(0.77)
FKR Fercent; NFV= EKR at a ERR (lising a 10 Year Cash Stream)	سال اعدا م.ا∗دا – ۱) ا	00 [°] 0	ບັບ	(4,46)		(4, 26)	(4 , n0)	(3,67)	(3.28)	(2.82)	(4,05)	(12.21)	(12.31)	(1, 34)	(1: '8)	(12.2)	(10,05)	(10.82)
							Fercent; [0_1	NFV= Year Cash	ERR Stream)	at a		ercent l)isc Rate.					

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100 100 <th>SITE COST/REWEFITS ANALYSIS Fa Fa Fif Steam Output: Au Thoy Ibs.Thr @ 2:0 psia: Me! Enthalpy (Rtus/Ib):</th> <th>ls A Si lugust 19,</th> <th>te Avail Second Avail Second Avail Second Avail Second Avail</th> <th>2.0</th> <th>Hours of GFC 7n96 < Input 0 2</th> <th></th> <th>13000 Coal Btu Content</th> <th></th> <th>e C</th> <th>Page 1</th> <th></th> <th></th> <th></th>	SITE COST/REWEFITS ANALYSIS Fa Fa Fif Steam Output: Au Thoy Ibs.Thr @ 2:0 psia: Me! Enthalpy (Rtus/Ib):	ls A Si lugust 19,	te Avail Second Avail Second Avail Second Avail Second Avail	2.0	Hours of GFC 7n96 < Input 0 2		13000 Coal Btu Content											e C	Page 1			
1 1 1 1 1 1 5 2 3		1985 Cast	Esc 198	: Rate 15-1990	1990 Es Cast 1991	ic Rate 0-2010									<							
3.1 0.0 5.1 5.0 <td> Cet Furch El Fwrlc/Lwh) Eoct BFC El Fwr Tr/Fwh) Electric Demand(\$/Fw/Ms)</td> <td>ad 0.00,0</td> <td>1</td> <td>5.00 laput> 5.00</td> <td>7.06 8.80 0.00</td> <td>5.00 5.00 5.00</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>Scran</td> <td>ton A</td> <td>đ</td> <td></td> <td></td> <td></td> <td></td> <td>-</td> <td></td> <td></td> <td></td>	 Cet Furch El Fwrlc/Lwh) Eoct BFC El Fwr Tr/Fwh) Electric Demand(\$/Fw/Ms)	ad 0.00,0	1	5.00 laput> 5.00	7.06 8.80 0.00	5.00 5.00 5.00						Scran	ton A	đ					-			
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M.h. 0.0 M.h. 5.00 M.h. 5.01	el Oil:\$/gal]	0.63		0.00	0.63	5.00																
	isting Cogen al Frice(\$/Ton)	M.A.		00°0	И.А.	5.00																
N.M. D.O. N.M. S.O. N.M. N.M. <th< td=""><td>al Heat Content tu/lb)</td><td>13000</td><td></td><td>NA</td><td>MA</td><td>R N</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></th<>	al Heat Content tu/lb)	13000		NA	MA	R N																
14 EF R44 149 199 1994 1	al Frice(\$/Mcl.Rtu) eam Fr % Esc Rate(%/yr) & M Esc Rate(% per Yr)	м. А. 4.00 М. А.		0.00 5.00 5.00		5.00 5.00																
1 28.00 2.00 73.46 34.26 31.2		1863	Rate 1-9ù	1985		1997	1988	1989		Esc Rate 1990-2009	1661	1992	1993	1994	5661	1996	1997	Fag 1998	•	Subtotal Yrs 1-10		
al 28.3% 2.0% 27.48 30.07 30.67 31.28 31.91 32.55 2.0% 31.20 31.30 31.88 34.51 35.23 35.93 36.45 37.19 38.13 38.90 4.12 5.0% 4.33 4.54 4.77 5.01 5.26 5.52 5.0% 5.89 6.09 6.19 6.11 7.05 7.40 7.77 8.16 8.51 8.57 4.12 5.0% 5.5% 5.5% 5.0% 5.80 6.09 6.13 7.05 7.40 7.77 8.16 8.51 7.05 7.40 7.77 8.16 8.51 8.55 5.0% 5.5% 5.5% 5.5% 5.5% 5.5% 5.5% 5.5%	H Asourt (Nil twhs) Un pest Interediate Off-pest																					
4.12 5.00 4.31 4.54 4.71 5.01 5.32 5.00 5.80 6.07 7.45 7.40 7.77 8.16 8.57 41 8.40 2.00 8.51 5.00 5.80 6.09 6.17 7.40 7.77 8.16 8.57 41 8.40 2.01 5.20 5.30 5.80 6.09 6.17 7.40 7.77 8.16 8.51 41 8.40 7.40 5.71 5.40 5.20 5.46 10.41 10.41 10.45 10.40 11.68 11.16 5.70 5.40 5.71 4.45 5.40 5.12 5.16	Subtotal		i i					į	32.55	2.00 Inputs	33.20	33.86	JA.54	35.23					38.90	356.37		
4.12 5.00 4.33 4.54 4.71 5.01 5.50 5.60 5.60 5.60 6.09 6.19 6.11 7.05 7.40 7.17 8.16 8.51 41 8.40 2.10 8.51 5.01 5.50 5.60 5.60 5.60 5.60 6.19 6.17 7.05 7.40 7.17 8.16 8.51 41 8.40 2.10 8.51 2.00 9.45 9.45 10.44 10.45 10.47 11.08 11.31 5.10 5.10 5.16 5.12 9.46 4.64 4.88 5.12 5.38 5.46 5.13 6.53 6.55 <	4 Rates(Cts/kwh) Sverage On poat S.erage interentiate A.erage Otf-peat																					
41) 8.40 7.01 8.51 8.74 8.74 10.04 10.24 10.44 10.65 10.87 11.06 11.31 1.70 5.00 1.47 5.64 5.64 5.64 5.63 6.13 6.13 6.13 6.164 11.31 1.70 5.00 1.47 5.00 4.64 4.68 5.12 5.36 5.44 5.93 6.13 6.13 6.13 6.164 11.31 1.70 5.00 1.47 5.00 4.64 4.88 5.12 5.36 5.44 5.93 6.13 6.13 6.13 6.164 11.31 1.70 5.00 2.60 7.46 4.68 5.12 5.26 5.13 6.13 6.13 6.13 6.164 8.16 8.12 5.16 31.71 37.49 31.65 8.145 86.69 81.45 86.49 81.45 86.49 81.45 86.49 81.45 86.49 81.45 81.45 86.49 81.45 86.49 81.45 86.45 81.45 86.45 81.45 86.45 86.45 8	 J.erall A.erage Lineer(4 Mag) Ket af Year			4.33		4.77	10.2	5.26	5.52	5.00	5.80	6.09	6. 39	6.71	7.05	7.40	1.11	8.16	8.57	1		
J. 70 S. off T. 44 S. 0 4.64 4.88 S. 12 5.54 5.93 6.22 6.53 6.66 1 25.00 2.00 2.41 4.42 5.00 4.64 4.88 5.12 5.38 5.64 5.93 6.53 6.53 6.53 6.53 6.54 5.96 6.54 5.96 6.53 5.64 5.93 6.53 6.54 5.56 6.53 6.53 6.54 7.54	as 24 Distribution(12 Mo Rat)			9. 57		8.71	4 0 °5	9.27	9.46	Inputs 2.00	9.65	9.84	10.04	10.24					11.31	ţ		
Milites) 101 25.00 2.00 2.01 25.50 26.01 25.53 27.06 27.60 28.15 2.00 28.72 29.29 29.88 30.47 31.08 31.71 32.34 32.69 31.65 65.70 2.00 67.01 68.25 68.22 71.12 72.54 799 2.00 75.47 76.99 78.52 80.09 81.69 83.32 84.95 86.69 88.42 0tal Year 90.70 92.51 74.36 96.25 88.18 [00.14]02.14	al Ma Rateis/Lavan) Istrutution (C. Musi					3.82	6 .el	4.21	4.4	5.00	4.64	4.88	5.12	5. 28	5.64	5.93	6.22		6.8 6	ł		
	(Mil 165) (g) otal Year								28.15 77.99 112.14	500 71 71	28.72	29.29 76.98	29.88						53.65 18.42	308. 28 810. 16		

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	r.	2.00	0,00	0.00	0,00	0.00	0.00	0,00	2.00	0,00	0.00	0.00	0.00	0,00	0.00	00.0	0.00	0.00	
Arg Rtw'Lb(Met) Pil Rtus Required	1052 95.42		1052	1452 99.27	101.26	1052 103,28	1052 105.35	1052		1052 109.60	1052 111.80	1052	1052 116.31	1052 118.64 1	1052	1052 123.43	1052 125.90	1052 128.42	1,176.60
Hot Water (Nij Gals)	0.00		0.00	0.00	0.00	0 ° 0	0.00	0.00		0.00	0.00	0,00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
å,g Rtu/Gal Eil Rtus Required	0.00		0.00 0.00	0.00 0.00	0.00	0.00 0.00	0.00 0.00	0.00		0.00	0.00	0.00 0.00	0.00	0.00	0.00	9.00 0.00	0.00	0.00	0.00
ETISTING COGENERATION																	P.	Page 3	
ect there Summer Rest of Yr	0.00	0.00 (Input) 0.00 (Input)	0.00	0.00	0.00 0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 9.00	0.00	0.00	0.00	0.00
 Subtotal	0.0	•	60°ŭ	0.00	0.00	0.00	0.00	0.00	0.00	00.0	0.0	0,00	0.00	0.00	0.00	0.00	0.0	0.00	0.00
Min Annual MW Dutput Avg Min Summer 3W Dutpt	0.00	0.00 (lnput) 0.00 (lnput)	0.00 0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 0.00	0.00	0.00	0.00 0.00	0.00	0.00	0.00	0.00
Steam Supply(Mil Lbs) Suamor Rest of Yr	0.00	0.00 (Input) 0.00 (Input)	0.00	0.00	0.00 0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal Avg Rtu/Lb(Net) Steam Rtus(Bils)	0.00 1952 0.00	1	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 6052 0.00	0.00 1.052 0.00	ı	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00 1052 0.00	0.00
16 Heat Rate Botler Efficiency Coal Rtus Required(Ril)	0.00 0.70 0.00	(Input) (Input)	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00		3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	3700 0.70 0.00	ŋ.00
(OSTS Elect Energy(1Mil) On-peak Intermed D#+-peak																			
	0.33 0.00	1	1.28 0.36 0.00	1.37 0.38 0.00	1.46 0.41 0.60	1.57 0.00	1.68 0.47 0.00	1.80 0.50	ı	1.92 0.54 0.00	2.06 0.58 0.00	2.21 0.62 0.90	2.36 0.66 0.00	2.53 0.71 0.00	2.71 0.76 0.00	2.90 0.81 0.06	3.11 0.00	3.33 0.93 0.00	24.94 6.97 0.00
- SubtotiNet of Engen)	0.11		n. 36	9.38	6.1	0.44	0.47	0.50	1	0.54	0.58	0.62		0,71	0.76	0.81	0.87	0.93	6.97
rntal flegt rusts	1.52		1.61	1.75	1.87	2.00	2.15	2.30	••	2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
METHOUT GEE & COSTS STEFENE																			
Eiteting Engen Enal Fags Ptus Required(Fils) Divis	0.60 0		00,0 000,0	0.0	01, 11 010, 11	0.00	0.00	0.00		n. (1)	0.00	00°0	0.00	0.00	0.00	0.00	0.00	0.00	0e.0
Total Constant)	0.00 0		90 [°] 0	0.01	0.00	0.00	(u'.u	0°0		0,00	0.01	00 [°] 0	0.00	0.00	00.0	0.0	0.00	0.00	0.00
\$rlin [nal	0 u 0	0.0	ан , н	0° 10	0.10	0.11	0	0°0	5.0)	00.0	0.10	0.0	0.00	0.00	0.00	0.00	0.00	0.00	
\$/Tun [geothna ¢/Tao fab Coored	00'0 0	0.00	u 1'u	ie ereini ereini	а с	8 1 2	90'a	90 °0	5.50	0.00 4	0.00	0°°0	0.00	0.00	0.00	0.00	0.0 20	0.00 20	
frimn Goh Feanwal Tebel Art	(m. 1)		11 ¹ 11	1 H T	: :	0°, 111	100 [°] 11	11 11 11	111	0	0,01	0- (EU	0.0	4 U0	9		20	0 00	

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	0.00	128.42	0.70		0.00	0.00	0.00	0.00	0.0	0.00	0.00	:	1 021 00	458.73	8.98 9.98	8.80	4.12	1 1	5.80	0.02	7.08	0.02	0.00	0.00	4.12	0.02	4.14		0.00	1.04	
	0.00	125.90	07.0 179.86		0.00	0.0	0,00	0.00	0.0 0		0.00	:	459.18	449.73	e.55	9, 9	3.85	1 14	5.80	0.02	6.74	0.02	0.00	0.00	3,85	0.02	3.87		0.00	0.99	
	0.00	123.43	9.70 176.33		0.00	0.00	0,00	0.00	0.0	0.00	0.00	:	81.001	440.92	8.15 1.00	84.1	3.59	1 27	5.80	0.02	6.42	0.02	0.00	0.00	3.59	0.02	3.61		0.00	0.94	
	0.00	121.01	0.70 172.87	:	0.00	0.0	0.00	0.00	8.0	0.0	0.00		11.53 100 100	132.27	1.76	/ . 60	3.35	10.1	2.80	0.02	0.01 6.11	0.02	0.00	0.00	3, 35	0.02	3.37		0.00	0.30	
	0.00	118.64	0.70	1	0.00	0.00	0,00	0.00	0.0	0.00	0.00	:	1 021 00 1	-		1.24	3.13	5	5.80	0.02	9.80 5.82	9.02	0.00	60.0	3.13	0.02	3.15		0.00	0.86	
	0.00	116.31	0.70 166.16	:	17000	0.00	0.00	0.00	0.0	0.0	0.00		124.21			6. BY	1.12	g	5.80	0.02	5.55	0.02	0.00	00.0	2.92	0.02	2.94		0.04	0.81	
	00.00		0. /0 162.90	:	0.00	0.00	00.0	0.00	8.0	0.0	0.00		1 001 00 1			9. 9	2.73	CU 1	5.80	0.02	5.28	0.02	0.00	0.00	2.73	0.02	2.75		0.00	ıı, 78	
	0.00	111.80			0.00	0.00	0,00	0.00	0.0 0	0.00	0.00		1 001 00 1	399.35	6.38 . 75	C/ 4	2.55	10 (5.80	0.02	5.03	0.01	0.00	0.00	2.55	0.01	2.56		0.00	0.74	
	0.00		0.70 156.58	:	00.00	0.00	0.00	0.00	0.0	0.00	0.00		399.74 • 021.00 1	391.52	6.08 202	ç	3.38	10 6	5.80	0.02	4.79	0.01	0.00	0.00	2, 38	10.0	2.39		00.0	0.70	
													2.00	5	5.00			ŝ	2017	:	8.6						1) 41			5.00	
	0.00	107.45	0.70 153.51	:	0.00	0.00	0,00	0.00	0.0	0.0	0.00		391.90	383.64	5.79	5.67	2.22	5	5.80	0.02	9.56 9.56	10.0	0.00	0.00	2.22	0.01	2.24		0.00	0.67	
	0.00		n.70 15n.50	:	0.00	00.0	0.00	0.00	0.00	8.9 8.9	0.00	1	384.22	376.32		5.6/	2.18	92 F	5.80	0.02	4.56	0.01	0.00	00.0	2.18	10'u	2.19		00°Ŭ	1.64	
	0.00	105.28	0.70	:	00.00	0.00	0,00	0.00	0.0	. 8 . 8	0.00		376.69	368.94	5.79	2.67	2.14	91 C	2.80	0.02	4.5b	0.01	0.00	0.00	2.14	0.01	2,15		00.00	19.0	
	0.00		0.70	:	00.0	0.00	0.00	0.00	0°,0	0°°0	0.00		369.30	361.70		2.6/	2.09	97 6	3.80	0.02	9.65 4.56	0.01	0.00	0.00	2,09	10.0	2.11		Û. ÛÛ	n, 58	
	0.00		0.70		0.00	0.00	0.00	Ú. N	0.00	0.00	0.00		362.06			5.67	2.05	57 6	5.80	0.02	4.56	0.01	0.00	0.00	2.05	10.0	2.07		u, Qu	ń.55	
	0.00	\$1.32	0, 70		0.00	0.0	0.00	0.00	0.00 •	0.00	0.00		354.96 01.00.	347.66		5.6/	2.01	8	2.80	0.02	9.65 9.56	10.0	0,00	0.00	2.01	10.0	2.02		0,00	4.53	
			(laput)		Input >								2.00 354.96	1 1ndut	0.00			Ę	(Input	5	0.0						8			5.06	
0.00	0.00	95.42	0.70 (136.31		0.00 (input)	0.00	0.00	0.00	0.0	00'e	0.00		348.00 . 61 30		5.51	2.40	1.88	12 5	2.80	0.02	0.00 4.34	0.01	0.00	0.00	1.88	0.0	1.89		00°U	0.50	
\$/Mil Ptus	[rgen [nal Cost(\$Nil)	=	Site Boiler Effics Suppl Fuel Rtus(Rıl)	Cost(Saee cogen builer)	Rtus Roquired(Ril) Bt./15	Intal Inns(000)	sifon-foal	\$/Ton-Limetone	\$/lon-Ash Removal	stat trient	[gal CostitMil)		Rtus Required(Rul) Devision Eb	1 61)		simil Rtu	Gas Cost (SMill)	fyel ()) birr Commentation	etus requires euro Rtu/Pbl (Mil)	Total Bals(Mil)	s/eal s/Mil Rtu	nii Eost(8Mil)	trital FUEL COST(\$Mil) Non-6FC Cogen Coal	Suppl Steam Fuels Coal	Seg	ניט	== 19tal Fuel Cost	(1W1 (} ₩ % 0 ask) (} W (Eisting Cogen O. 4. M	Sugpl Thermal 7 & M	

A.3-4 9.45 4.26 4. H 1.04 8.84 3.98 3.87 0.99 į 8.27 3.72 3.61 0.94 1 1.74 11 3.37 0.90 7.24 3.24 3.15 0.86 3.02 2.94 6.78 0.81 ł 2.82 2.75 6.35 (, 78 2.64 5.94 2.56 0.74 Ì 2.46 2.39 0.70 5.56 -----2.24 5.20 2.30 0.67 -----2.15 2.19 4.98 0.64 2.00 2.15 4.76 0.61 7.11 1.87 4.56 0.58 -1.75 2.07 0.55 4.36 1.63 0.53 4.18 2.02 1.52 1.89 0.50 3.91 -----INTAL NON-GFC CASE COSIS Furch Elect Fower Total Costs Furch fuels H J ()

5.00 9.24 9.70 ut 0.00 0.00 ut 0.00 0.00 0.00 0.00 65.28 65.28 65.28 65.62 65.28 65.62 0.05 0.07 0.35 0.37 0.35 0.07	0.00 8.80 N.A. (Input N.A. (Input 8.65.28 68.68 68.68 68.68 0.00 0.00 0.00 0.00
5.00 9.24 0.00 0.00 69.68 6 69.68 6 0.35 0.35 0.35	8.80 M.A. (Inp 65:28 68.68 5.10 0.00 0.00 0.00
0.00 0.00 68.5.28 6.5.28 6.5.28 0.00 0.35 0.35	M.A. (Inp M.A. (Inp 65.28 68.68 5.10 0.00 0.00 0.00
0.00 65.28 68.68 6.35 6.35 0.35 0.35	0.00 65.28 68.68 5.10 0.00 0.00 0.33
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RECEIPTION REPORT AND A DESCRIPTION OF A

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4.19	0.52	0.49	0.47	0.45	0 .4 2	0.40	0.39	0.37	0.35	0, 33	Gubtetal
4.19	0.52	0.49	0.47	0.45	0.42	0,40	ų. 19	0.37	(0.33	Fur≤h BFC Thermal
0.00	0.0	0.00	00.00	0.00	0e.0	0.00	0.00	0.00	0.00	0.00	Furch Aff. Elect fur
											W.th GFC Facility
71.37	9.45	8.84	8.27	1.74	1.24	6.7B	6. 35	5,94	5.56	5.20	Subtetal No 6FC
8.43	1.04	66.0	16.0	0.90	96,0	18.0	87.0	0.74	0.70	0.67	5 × 5
31.03	4.14	3.87	3.61	3.37	3.15	2.94	2.75	2.54	2.39	2.24	Furch Fuels
31.91	4.26	86.1	3.72	3.47	3.24	1,02	2.82	2,64	2.46	2.30	forch Elect Fur
									•		Without GFC Facility
											COST/REMEFIT SUMMARY
4.65	0.57	0.55	0.52	0.50	0.47	0.45	0.43	0.41	0.39	0.37	Supri @ \$ # Cost
3.77	0.47	0.44	0.42	0.40	0.38	0.36	0.35	0.33	0.32	0.30	sbuines W # D
8.43	1.04	0.99	0.94	0.40	0.86	18.0	0.7B	0.74	0.70	0.67	Suppl Thera Flant
0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00	Evisting Cogen Flant
											D.L.M.Cost (\$Mil)
23.85	3.26	3.03	7.81	2.61	2.42	2.25	2.09	1.94	1.80	1.67	Suppl fuel Cast(#Mil)
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	00.0	rite (root) [gst (fWi]]
0.00	0.0	0.0	0.0	0.0	0.00	0.0 1	0.0	0.0	0.00	ú0°0	fuel Oil (Mi) Gals) Trucconstruction
00.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 . 00	0.00	Ptus Reg (Bill
23.85	3.26		2.81	2,61	2,42	5.25	2,09	1.91	1.80	1.67	(ost (#Mil)
3, 310. 13 3, 242.05	362.61	361.07 353.64		343, 24 336, 18 3	334.58 327.70	326.10 319.39 2	311.24	309.63 303.26	301.63 295.43	293.79 287.75 5.70	R ^e us Req. (811) Lat 5 st (11) [j, ft] Lat to ft/Matin
0.00	0.00	0.0	0,00	0.0	0.00	0.00	ÚŬ*0	0.00	0.00	0.00	Cref (#Mil)
	00.0	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.00	00.0	Frice (B/Ten)
0.00	0.00	0.00	0.00	0.0 0.0	0.00	0.00	0.00	0.00	0.00	0.00	Rtus Req (Ril) [cal (ru0 [cars)
											Man-fff fuel Rega
`~	Л. 3 -			£	314.58	326.10	<u>81.78</u>	305.63	301.63	67.79	fuel Btus Reg (Bil)
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					e S						

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1.1.1	J. 3 - 7		31.91	23.85	55.77	4.65	64.61	6.76 6.76 10.95		
			4.26	3.24	1.52	0.57	8.61	0.84		
			3.98	3.03	7.00	0.55	8.04	0.80		
			3.72		6.53		7.51	0.72 0.76 1.17 1.23		
			3.47	2.61	6. (iB	0.50	7.02	0.72		
			3.24	2.42	5.66	0.47	6.56	0.65 0.69 1.06 1.11		
			3.02	2.25	5.27	0.45				
<u>ي</u>			2.82	2.09	15.4	0.43	5.72	i		
			2.64	1.94	1.57	0.41	5.35	0.59 0.96		
			2.46	1.80	4.26	0.39	5.00 5.35	0.56	1990 MFV at Discount Rate of 20.00 Z	2.27
		;		~	-	~	~			
7			2,30	1.67	3.97	0.37	4.67	0.54	Cueulative Savings	10-Years 6.76
										10-Year
									OF SAVINGS:	
189 VIN 112.									FINANCIAL EVALUATION OF SAVINGS:	
									F I NANC I	
			jar L				Subtotal With EFC	5 ritrij) Z GEC		
			Suppl Elect Fur	sland fuels	Suptat	H • 0	5 uht at 41	NET GEE SAUTNES (EM.)) Aucholed cost w/ EFC		
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N N N	n AAP Analysi Fuel C					•							
	A.(Scranton AAP GFC Plant Analysis (Vestinghouse Fuel Cell)												
R.S.A	GF (Vest								44 10 11 11		Dther 0.00	1	19.83 Fercent 19.83 Fercent
	99.26 (Input us/Yr	12	49	41.17 0.00 (8.48)	18/	S	88	222323	75		•		5 6
	Ri A	25.12	181.64	41.17 0.00 (8.48	(82'65)	114.55	0.00	4.97 9.22 241.26 70.25 118.65 118.65	700.75		• + Tars/Oils 2 0.00	2	Equals: Equals:
	at Mil Btus/hr of Input								98.75 Mil Blus/hr 700.75	iil Btus!	+ Steam 25.12	704.35 Coal In	Hrly Efficiency Equals: Annual Efficiency Equals:
) I	704.35 at Mil 13.020.00 (Input 27.048.73 91.48									Annual Calc (bil Btus)	Net Fwr Dut 114.55		В
	Rtus Coal: Rtus/Lb: Tons Coal: Tons/ Day: Tons/ Day: fil Rtus/hr	3. 5 .	25.40	5.80 0.00 (1.19)	(14,06)	16.14				đi	K Founds:		9.20 (Eross power out)
	7.50 Bil 7096 (Input Annual						hr (Input hr (Input	hr <lephoneter hr </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter </lephoneter 	ł		+ Other 0.00		_
		3470 Lbs/hr 1020 Rtus/1b	7.50 18	1.70 MW 0.00 (0.35) MM	(4,12) MI	4.73 R	0.00 Mil Btus/hr 0.00 Mil Btus/hr	0.70 Mil Btus/hr 1.30 Mil Btus/hr 34.00 Mil Btus/hr 9.90 Mil Btus/hr 16.77 Mil Btus/hr 16.45 Mil Btus/hr	98.75 Mil Btus/hr		*		t Fate: 10,404.41 95.72 Divided by ainus 6 Tarsi
	Rated Output (MM): Avail (Mrs per Yr):	M -	1	- 0 0	Ξ	•	00	0 - <u>5</u> - <u>2</u> - <u>2</u>	86		+ Tars/Dils n.on		Gros Heat Rale: 95.72 (Cral minus Stean & Tars)
		Input) Input)	Input >	Input > Input > Input >	Input >		t t	*******	1. 14 17 18 18 18 18 18 18 18 18 18 18 18 18 18	(ei] Btus)	t ftea 3.54	55.26 Cal In	4,73 (Net Fwr)
12. 12.	Site: FA August 19, 1985			-				l Cwer		Hourly Calc	Net Fwr Out + Steam 16.14 3.54		24,236.91 Divided 6v
	GFC FLANT ANALYSIS Mestinghouse Fuel Cell / ENERSY BALANCE SUMMARY	Steam Output: Thou 1bs/hr @ 240 psia: Net Enthalpy Sain:	Electric Fwr Output: Foel Cell Output	Gas Expander Dutput Thermal Mgt System Fower Conditioner Losses	Aux Fwr Regs	Net Fwr Out Other Outputs:	Tars/Guis Ather(e.g., Sul,Ammon)	sses Ash Cyclone Earbon Dust Mait Rejected b, Fnoling Tower EU Shift Air Cnoler H566 Stark Locs Miscellaneous	TOTAL RTUS:	H :FELETENCY:			Nat Heat Fote: 95,72 (Cal arras Staze & Tare)
	GFC F Mesti ENERG	Stear Tho Net	Elect Fue	Gas The Fou	Aus	Net Other	1ar Ath	Lo:ses Ash Cyclo Heat H566 H566	101AL	GFC F			ر به ا

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ECONOMIC & FINANCIAL Assumptions				
	All Inputs 1005	All Inputs		All inputs
	Energy Cast	Annual Escal. Rate 1985-1990	Energy Price 1990	Annuai Escal. Rate 1990-2010
FFLL Avaided Cost (cts/kwh	3.20	29.40	8.10	5.00
Electric Demand(\$/hw/Mo)	00'0	5.00	00.0	00.2
Other Deand(\$/bw/Mg)	0.00	5.00	0.0	0.2
Natural Bas(\$/acf)	5.79	0.00	5.79	5.00
fuel Dil(\$/gal)	0.63	0.00	0.63	5.00
Coal Price(\$/Ton)	58.00	0.00	58.00	5.00
Coal Heat Content (8tu/1b)	13,020.00	A	A	A M
Coal Frice(\$/Mil.8tu)	2.23	NA.	2.23	đ
Steam Frice & Esc Rate	1 .00	5.00	5.11	5.00
0 % M Esc Kate(% per Yr)	N.A.	5.00	N.A.	5.00
	1985 Existing	1990-2010		
Depreciation Nethod	ACRS	ย		
Depreciation Tereffears) Equipment Utilities & Other	5.40 15.00	5.00	Percent of Equip 100,00 0,00	Per cent Per cent
Invoctaent Tax Eredit	10.00 2	10.00 2		
Monconventional Gas Annual Income Tax Credit (\$/Mil. Ptu)	02.0	0,00 (thru 1995)	5.00	5.00 Percent Esc Rate
Investor's Annual Incore Ia: Rate (Corbined Fod. & State)	2 00 05	20,00 2		

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arameter Assumption	ercent Government unding	ercent Private	unoing Percent equity	Fercent debt	Interest rate	Loan tern(years)	Constr int rate	Constr loan acount(\$Mil)	lst yr portion	2nd yr portion

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CONSTRUCTION COST DEEADDAW (6411)	F	SITE: PA	erc sı	6FC SIZE:7.5 HM				GFC O & M COST	л. Т		-	V + - Y			
		5.	5.00 % Esc Rate 1985\$	Rate 35\$ 1589\$	-	en Costs 37 15	Feriod When Costs Mill Occur 1987 1588 198	. 5	11) Escal .Kate:	: 5.04 1 19858	\$0561 I	1995			
Coal Hndlg & Gasif. Ear Erroration & Euclase	lf. Euchaar	÷ م	6. B.		20.00	00 40.00	00 40.00	00 Direct Labor	0.70			-			
rucessing 'sy Fuel Cell/Fue Cond. Thermal Mgt Syst. Balance of Flant	and.	22.00	. 8 6 6					Fringes e 202	Z 0.14						
		Subtotal		17 40 71		PC 81 71		Contract Maint.	nt. 0.20						
			÷					Chem & Supplies	ies 0.15						
Freintupe Investment(Inc) abovel Unique Site Costs	aent(Inc) above) ;		0.00	00 0.00 80 1.45	0.00	00 0.00	00 0.00	0 Spare Parts 15	0.05						
_			:					Water/Utilities	ies 0.10						
General Conditions([nr] above)	is([nr] above)		00 ° 0	00.0	0.00	0.00	0.0	Ash/Sludge Disp O	isp. 0.10						
Design & Engineering(lac) zhove)	inglari zhove)		0.0					Niscel	0.06						
Freproduction Costs(Incl above) Contingency at a Percent of:	sts(Incl above) Percent of:	0.00		00.0	0.0		8.0	0 Subtotal		1.50	1.91	2.44			
IDTAL CONSTRUETION COST:	:1203 N	:						· Wheeling Charge	ž	0.00	0.00	0.00			
Land			0.00					Fuel Cell Reloading 0 Costs E\$60/#w(1985\$)	oading (1985\$)	đ	M	0.73			
Other Special			0.00	:00°0 (0	0 : 0.00	00.0 00	00.00	o (per' year)	-						
								TOTAL D & N		1.50	1.91	3.18			
TOTAL CONSTRUCTION . SPECIAL:	14 · SFECIAL:		45.36				00 22.05				**********				
UTHER CAPITAL COSTS	DHER CAFITAL COSTS			40 N N N N N N N N N N N N N	8 8 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9		***	======DiHER ANNUAL EIPENSES Legal/Account.	EXPENSES .	0.00	0.00	0.00			
Morting Capital Arcts Rereivable 015 days cort Torreivable 015 days	e ets days	0.65	5	£7.0				Insurance Prop. faxes		0.15 0.00	0.19	0.24			
rues covencory eto days Other Inventory/Supplies	saplies //Supplies	0.10	10	0.15 0.12 :	0.00 2 : 0.00	0 0 0 0 0 0 0	0 0.15	5 2 Contract Oper. Fee	. fee	0.10	0.13	0.16			
Accuts Fayable elû days	elû days	(0.11)	-	10.13)	0.6 .	00.0 U			,,	0 , 22 42 42 42 42 42 42 44 44 44 44 44 44					
Subtotal Nor	Subtotal Working Capital			25.0	u0'0	00°0 U	0 0.92	1014L 01HER 2	·	0.23	0.32	0.41			
Frix Fin Fees at Percent of: "vd Fty Own Fee at Percent of: Ather Expenses at Fercent of:	Fercent af: it Percent af: Fercent af:	9.0.0 7.10 8	8.00 X 2.00 X 2.00 Z	1. 30 0. 32 9. 32	0.00	0 0 0 0 0 0 0 0 0 0 0									
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2.11
0.35 (5.12) (0.79) 4.19 0.75 2.02 0.00 0.00 0,00 3.02 0.75 0.00 2.56 0.03 FA SUIE Operating Ferrod (4, 35) (4, 71) 3.06 0.14 0.00 (0.79) 2.11 (0.38) (16.2) (0.32) 1661 (5.18) 1.65 2.01 0.34 0.75 1.36 3.20 3.99 0.00 0.00 -----0.0 3.02 0.00 0.75 8.0 2.59 0.00 GFC CF ANALYSIS (0.45) (96°U) (3.17) (0.43) (5.44) 1930 2.72 0.15 0.00 1.57 1.91 0.32 2.84 3.80 0.75 1.46 2.21 0.0 8.0 0.00 3.02 0.75 2.72 ΰ°υ 30.00 Fercent) 30.00 Fercent) 0.00 0.00 Engineering/Construction (**1**6.5) 1969 0.00 0.00 0.00 0.00 0.0 0.0 0°.0 0.00 (Constr Loan Interest) 0.00 0.00 0.00 (16.78) (1671) 0.00 0.00 0.00 Fercent) 1.59 0.00 f/Mil Rtu to 1997) 11.24 CPAL GASIFICATION-FUEL CELL-COGENERATION FLANT AT: 0.00 0.00 00.0 SITE (Private share of equipment) 1589 0.00 0.00 8.0 8.0 0.00 9.00 0.00 0.0 0 8.S 0.0 0.00 70.00 Fercent) (a. o 0.00 0.0 đ 1987 0.00 0.00 0.0 0 u 0 0.95 0.00 00° 0 0**.**00 0.00 0.0 8.0 6 0 0.00 e.s FINANCIAL ANALYSIS (SNIL) Depr 5-yr Equip(SL) at Depr 45-yr Equip(SL) at Ta: Saving or farsont(-) Debt Service: Frincipal Interest frij Capital Requirement Friv Form Debt Financing :126.63 1. C. Inv. Tar. Credit at li able income∕loss(-) Srugas Tar Gredit at Amort Startup Cost Seriative Cash flow PFERATING CASH FLOW Frincipal Faymont Debt S.c Reserve RESIDUAL CASH FLOW Dobt S.c Reserve Coverage Fatio lar Adjustments Perating Costs fury Feerve Manayomont Fee אבנ טפא צועא Electric Subtrtal Subtotal 5 ibtotal lher all Savenues W 2 Ū Other Other Fue l ite.

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at a (152.03) fercent bisc Rate. 43.67 1¹¹ Year Cash Stream) (1.52) Fercent and NFV= Using a

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	27.70 fercent	Equals:	Coal In Coal In Hrly Efficiency Equals:	:	20.215,01	Gros ^c Heat Rate:	с]	456 hour 6 the 5
	+ Other 0.00	+ Tars/Dils 0.00	Met Fwr Out + 5tean 297.89 68.68	Ret Equals:	+ 0ther 6.00	• fars/01 5 0,00		Nev Far Dut 41,28
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		(8), 19)		(12.29)	Į	(3,60) 111	lnput > 	ân: Fwr ƙegs
		60.55 58.12 (14.53)		8.53 8.19 (2.05)	22	2.50 MM 2.40 (0.60) MM	Input) Input) Input)	iss Erpanfer Oùtput Neræl Mgt System Fr⊶er Eanditioner Losses
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n AAP Analysis (Cell)	Scranton AAP GFC Plant Analysis (UTC Fuel Cell)		50,902.88 172.16	l Tons Coal: Tons/ Day:				ENERTY PALANCE SUMPARY
A.5-1	ž	186.51 <1∩put	1,323.47 at Mil Btus/hr of 13,000.00 (Input	l Rtus Coal: Rtus/Lb:	11.00 Ru 7096 (Input	Rated Output (MW): Availithes per Yr):	_	6FC FLawr מאתע YSIS August 19, 1985

							(Inout		(Input (Input	<pre>{Imput</pre>	(input	<pre>cinput </pre>	< Input								
				70.00 (Input				67.00	13.00			0.40									
		Assumption		70.00		10.00	AN 16.2				(\$411)										
DWHERSHIF AND Financing Structure		f ar aneter	Fercent Government	Funding		Fercent Frivate Funding	Fercent equity	Fercent debt	Interest rate Loan terniyears)	Constr int rate	Constr loan acount(\$Mil)	2nd yr portion	Jrd yr portion								
	All Inputs	Energy Frice Annual Escal. Rate 1930-2010	5.00	(pediuurud in 1995)				5.00	5 ,00	R R		M	5.00				ercent	Percent		5.00 Percent Esc Rate	
12.26	4	Energy Frace 1990	8.90	8.80	8.80 9.20	9.30	12.71	0.63	58,00	13,020,00		2.23	5.11 N.A.			Percent of Fours	100.00 F	0.00 Percent		5.00 Pe	
	Ail Inputs	l. ƙate 85-1950	0461	1591	1972 1921	1661	5651	0.00	v0°ů	ų.		M	5.00	0102-0661	SL		5.00	15.00	10.00 1	(1,00 0,000	59. ro 2
July to	Ali Inputs Al Isas		uZ*1					0.63 (Not used	58. NN	13,620,80		2.25	A.00 A.A.	1985 Existing	ACRS		5.00	15.00	1 00'01	07.4	1 (1)
ECONOMIC & FINARCIAL J. Assumetions	Ē		 Aveided fl Costs (r/lwhl					Puer Ulits gall	Cnal Price(\$.Ton)	Coal Heat Content Parts 141	101-51	[aal frice(\$/Mil.8tu)	Steaminice the Eschate 21 th Eschatelt partic		 Gafrerjation Mothed	Esprectation Teralitears)	Equipment	l'ilites & Other	jstactant las (tedit	Marchantlonal Fac Annual İncree Fa Fredit 1 Mart - Fredit	ła paskar a daruji Inroko Tar Egta Ifrahjani End, t stypi

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Chal Walfy & Ravid. Rae Frencening & Sycteae Fuel Salf, Fer Cond. Freead Mg9 Sych.	5,27 9,26 7,16	-		The line line line line line line line lin	40,00 1985 capit	40,00 40,00 ital costs ction year)	Direct Labor Fringes @ 20% Contr Oper Fee	0.80 0.16 0.10	1 0841	1465	\$355T			
for 1 fr. aver and	2,09 Subtatal		5. 10 2. Eer Fate 	1.76	16.30	17.11	Contract Maint. Char & Summing	0.22 A.10						
frefnisz lastambilaci ztavel Majas Sita Casta	_	0, no 7, 90		0.00 0.86	0.00 1.81	0.00 1.90	Spare Fts/Maint Sup Mater & Site Utils	0.30 0.10						
Gaaral Constituacilari abovet		ĥ,ĥÌ	0.00	Û.Û	Ú. 00	0.00	Ash/Sludge Disp. Miscel	0.08 0.07	, L	Fsral, Rat	U U			
Beign & Fngineering(Incl above) Fregr durtion Enstalact above) Fantingenry at a Fercant of:	0. QA	0,00 0,94 0,00	0.00 :	0.00 0.10 0.00	0.00 0.38 0.00	0,00 0,38 0,00	Subtotal			2.57	3.27			
ורייק בנהישר בהאבוצהבונטא בנהבו:		00'e	46.89 0.00	9.00 0.70	18.49 0.00	19.39 0.00	Wheeling Charge Fuel Cell Reloading Costs 1985 \$ of:	33	0.00 MA	0,00 MA	0.00 0.60			-
Photos Special		0v~1	1.22 :	0.4i	0.41	0.41	1014F 0 & M		2.01	2.57	3.88			-
TATAL CHRISTENCTION + SEELIAL: """"""""""""""""""""""""""""""""""""	SFECIAL: AL. na	41'U#	48.10 :	68.81 14.8	18.89	19.80	======================================	17 17 17 17 17 17 17 17 17 17 17 17 17 1	0.00	0.00 0.00	0.00			
Korkang Fanted Romonts Feervahle: Fuel Incontory/Supples: Fiber Incontory/Supples:	12	days da ys	0.99 : 0.12 0.10 :			0.99 0.12 0.10	Insurance Frop. Taxes		0.20	0.26	0.09			· .
kreinnts Farahle: Subtotel Korking Capital	<u></u>	days	(0, 16)		·	(0.16)	TOTAL OTHER		0.20 0.26 0.33	0.26	0.33			
friv fin fes af førent gf: fri fiv Das føø af førent gf: Piter E gønses af førent gf: Sibtetal	8.00 Z 2.00 Z 2.01 Z	, ,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	1.18 0.29 0.29 1.77			1,18 0.29 0.29 1.77								
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6.52 0.46	0.46		0.00 0.00 0.00 0.00 0.00 23.47 22.88	0.00 0.00 0.00 0.00 0.00 1.47 2.88	0.00 0.00 0.00 0.00 0.00 0.00 23.47 22.88	0.00 0.00 0.00 0.00 0.00 0.00 1.00 1.02 1.02	0.00 0.00 0.00 0.00 0.00 0.00 1.02 1.02	0.00 0.00 0.00 0.00 0.00 2.47 2.88 3.17 3.17 3.19 3.69	0.00 0.00 0.00 0.00 0.00 2.47 2.88 3.77 3.89 3.89 3.89 3.77 3.89 3.77
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1.5-5 15.15 0.58 0.00 0.68 0.08 0.00 (2.56) 2000 ----..... 15.73 4.81 0.42 10.13 1.13 4.94 0.00 1.43 5.56 0.0 0.0 5.11 -----1.87 10.12 104.78 109.25 37.13 75.95 (5.31) Subtotal 0.00 6.82 16.14 2.06 0.0 17.16 0.00 3.36 6.82 0.00 1999 Yrs 1-10 4.47 3.21 33.29 N.A. 10.62 0.00 33.00 Fercent 67.00 Fercent 0.55 0.05 11.98 4. 71 4. 71 0.53 0.90 (2.38) **0**.€ 9.69 5.29 4.36 8°. 0.00 1.08 0.0 0.0 4.76 0.00 1.70 8.25 1.21 (12.2) 13.74 0.0 14.27 4.36 0.00 1998 0.38 1.2.9 5.04 0.68 0.62 1.30 3.87 0.8 0.00 3.74 0.0 1.42 0.0 1.53 6.55 0.0 27.43 Percent Disc Fate. (10.2) 50.92 30.00 30.00 13.07 13.59 1.15 1.28 0.36 0.68 0.71 1.39 0.0 0.6B 1.36 5.03 0.00 8.79 8.0 8 0.00 1977 8. 3.41 8.8 4.09 Tot Cap Costs of 5.04 times t0.23 times (1.85) 12.46 0.48 12.94 3.96 9661 0.00 8.37 1.57 0.68 0.80 .48 3.09 0.0 0.00 3.09 0.0 0.00 0.00 3.77 0.0 1.20 3.66 (1.73) 11.87 12.33 3.*1*1 3.**8**8 99.0 98.0 8.8 5491 0.0 0.33 2 2.77 2.78 0.0 0.68 3.47 0.00 20.1 2.46 1.97 1.57 0.0 (0.12) (11.2) 8.55 0.93 8.12 0.00 3.59 0.48 2.67 0.68 7.02 1.53 1.66 0.93 0.00 0.0 0.0 1.06 0.00 Ξ 4t a 1994 Friv Eqty Priv Debt (0.13) (1.98) 8.03 0.41 0.00 3.42 2.97 0.30 0.68 1.06 8.8 2.67 0.68 0.90 14 Year Cash Stream) 1993 8.4 6.69 1.76 1.75 0.0 0.00 8 9.48 1.01 0.01 0.99 27.43 Fercent and NFV= (0.13) (2.12) (U. 5 . U) 2661 7.68 8.07 3.25 2.83 0.28 6.36 0.68 1.15 0.93 0.0 0.0 0.0 2.67 0.68 0.00 1.06 1.71 1.84 0.00 0.93 F.A SITE **Operating Feriod** (2.43) (1.46) (1.92) 1991 7.68 3.10 2.69 0.27 2.67 0.68 0.00 1.03 8.06 6.06 1.99 0.68 1.24 . 92 10.1 0.0 0.0 0.07 0.0 0.96 0.0 (1.76) GFC CF Analysis e buisn 7.68 2.95 2.57 0.26 0.68 0.0 2.67 H.1 0561 8.0I 5.17 2.24 0.23 0.00 0.68 0.00 0.88 0.9 2.01 1.1 (1.60) 15 Yr 15 30.00 Fercent) 30.00 Fercent) 0.00 0.00 Engineering/Construction 1987 1988 1989 (15.27) (04-1) 0.0 0.0 0°°0 -----(Constr Loan Interest) 0.00 0.00 0.00 0.00 \$/Mil Btu to 1999) ΰ°ΰ 0.0 0.00 0.00 0.0 0.00 0.00 0.00 ΰů ů Ξ. 1...23 ÷ 303 COAL GASIFICATION-FUEL CELL-COGENERATION FLANT AT: (Private share of equipment) 0.00 0.00 0.00 30.00 Fercent) ų vu 0.00 0.0 0.00 0.0 0.00 0.00 0.00 0.00 0.00 00.0 3 0.0 0.0 0.00 0.00 0.00 0.0 0.00 0.95 0.00 0.00 0.00 00°0 00[°]u 0.00 0.00 0.00 Depr 5-yr Equip(SL) at Cepr 15 yr Equip(SL) at FINDALISE CHARLYSIS I FINILI Debt Service: Frincipal Interest la: Saving or Faveent(-) friv Capital Requirement Priv Ferm Debt Financing 10 7. Inv Ta∵ Crodit at farable Incomp/Loss(-) Surgas tar Credit at Andret Startup Cost Frincipal Faymont رسيباغاياته وعدك فامس **JFERATING CASH FLOW** Cebt Svc Reserve Cebt Suc Reserve FESTOUAL CASH FLOW Coverage Ratio lar fjjustærnts Gueul Feserve Dierating Costs tanagerent Fee NET CASH FLOW Subtotal Subtotal Schtotal Electric Thereal 531100103 H / O <u>Other</u> Other fii d l ea

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Subtotal Yrs 1-10 160.23 -....... ; ł 510.61 1,817.26 2,327.87 ł 6661 16.14 16.17 51.52 183.36 234.89 13.86 Page I 3.09 13.51 Page 2 51.42 183.09 234.42 **8**66 E 12.87 3.09 13.20 16.10 12.26 3.08 12.57 51.32 162.63 233.95 1997 16.01 16.04 16.07 11.67 51.21 182.27 233.48 1996 11.97 3.07 1.1.1 5651 11.12 11.40 3.07 51.11 181.70 233.02 1561 10.59 10.86 51.01 181.54 232.55 90° 1 15.97 1661 10.34 10.08 3.05 50.91 181.18 232.09 TATALYSIC 411 F 1 111 f the could 15.94 50.81 180.82 231.62 2661 9.60 3.05 9.85 15.91 9,15 50.70 180.46 231.16 1991 3.04 9.38 . Esc. Rate 1990-2009 Input -0.20 5.00 0.20 0.20 Input 0.20 5.00 1990 50.60 180.10 230.70 15.88 8.33 8.71 10.1 15.85 59.50 179.74 239.24 6861 3.03 **B.** 30 8.51 848 (84) 215, 1988 15.82 50.40 179.78 225.78 0.5 7.90 P. 10 fine fact 1950 Ex Kate Cost 1530 Zolu 15.78 50.30 175.02 229.32 8 8 8 8 9 8 1987 7.52 191 ç 977 5.10 5.00 Ĩ 3.02 21.5 Avail Heurs of 6FC 205A Input 10.76 15.75 9, ° 01 50.20 178.66 228.86 56 0 0.0 7.66 #. #. 986 l 7.17 (Effective wheeling demand charge) 6.67 5.00 7.00 7.35 9 10 А. Н e i (Fart 1985 1950) 15.72 204-00 1/51 θ., Esc Hate З. З 5. 10 5.00 6.83 01--0 178.51 228.41 0. 0 0..0 5851 Ş 5.6 Ξ. Input -Input -0.20 5,05 Sold 2 61101 06 \$851 \$861 0.20 0.20 0.20 Esc Rate August 19, 1785 Si te SITE ENERGY USE AND RENEFITS ANALYSIS 7510 0.00 6.00 N.A. 1385 [ost 8.41 а. <mark>9</mark>5 15.59 14.67 50.00 177.95 227.95 6.50 Ξ Я.А. . . . М.А. Nat Enthalp, Gain in Brus'lb: ä they the the P. 124 permit lotal ti vikadi i Natural Eac Frine(1. act) Coal Frice(\$/Mi].8tu) GFC Sta Frice & Esc Rate C & M Esc Ratel's per Yr) GFL EI Fur Friceic/kuhl Total Furch El Fur Cost Stean Devand(Mil Lhs) Total Year Average intermediate إشفا سال وتاتفرو فعاي HWH Amount (Mil Luhs) feat MM Fate(1:5w/Mg) Fe Ft. Hainwright Existing Engen Eal Frice(\$/Tent HH Rates(Ets/1wh) Summer (4 Mr) Rest of Yr 139 LENDIN IN GREWIG A. praje off push Coal Heat Content 4. erage fa peat Querall Average]_termediate Off peak ELECTRIC FUNER Summer 14 Prs brand MM leard THEFMAL DEMAND Steam Dytput: seat of teat ils hi (r peat (Btu/lb)

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	λ.	21.52	1051 246.86	0.00	0.00	Page 3	0.00	0.00	0.00	0.00	0.00 0.00 0.00	° ° ° ° °		2.18	0.51	0.51	2.70		0.00	7510 0.00	0.00 0.00 0.00	•••
(51.42	1051 246.37	0.00	0.00 0.00	2	0.00	0.0	0.00	0.00	0.00 0.00 0.00	0.00 0.00		2.08	0.49	0.49	2.57		0.00	7510 0.00	0000 0000 0000	
		51.32	1051 245.88	0.00	0.00 0.00		0.00	0.00	0.00	0.00	0.00 0.00	0 .00		1.97	0.46	0.46	2.44		0.00	7510 0.00		•
		51.21	1051 245, 39	0.00	0.00 0.00		0.00	0.00	0.00	0.00	0.00 0.00 0.00	0 0.00 0.00		1.88	0.44	0.44	2.32		0.00	7510 0.00	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	
		51.11	1051 244.90	0.00	0.00		0.00	0.00	0.00	0.00	0.00 0.00	0 0 0 0 0 0 0		87.1	0.42	0.42	2.20		0.00	7510 0.00	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	
		51.01	1051 244.41	0.00	0.00		0.00	0.00	0.00	0.00	0.00 0.00 0.00	° ° ° ° °		1.69	0.40	0.40	2.09		0.00	7510 0.00	8 8 8 8	
,		50.91	1051 243.92	00.0	0.00		0.00	0.00	0.00	0.00	0.00 0.00	0.00		1.61	0, 38	0,38	1.99		0.00	7510 0.00	8 8 8 8 0 0 0 0	
4 4		50.81	1051 243,44	0.00	0.00 0.00		0.00	0.00	0.00	0.00	0.00 0.00	0.00 0.00		1.53	0.36	0.36	1.89		0.00	7510	8888	
		50.70	1051 242.95	0.00	0.00 0.00		0.00	0.00	0.00	0.00	0.00	0.00 0.00		1.46	0.34	0.34	1.80		0.00	0.00	0.00 0.00 0.00	
222		0.20						i			ŧ			i		i	h				5.00 5.93	
		50.60	1051 242.46	0.00	0.00		0.00	0.00	0.00	0.00	0.0 0.0	0.00 0.00		1.38	0.33	0.33	1.71		0.00	7510 0.00	0.0	5
		50.50	1051 241.98	0.00	0.00	nwright)	0.00	0.00	0.00	0.00	0.00 0.00	0.00 0.00		1.31	0.31	0.31	1.62		0.00	7510		•
		50.40	1051 241.50	0.00	0.00	m Ft. Wainwright	0.00 0.00	0.00	0.00	0.00	0.00 0.00	0.00 0.00		1.25	0.29	0.29	1.54		0.00	7510 0.00	6 6 6 6 6 6 6 6	
		50.30	1051 241.02	00.0	0.00	purchased from	0.00	00.0	0.00 0.00	0.00	0.00 0.00	0 0.00		1.19	0.28	0.28	1.47		10'0	7510	0.00 0.00 0.00 0.00	•
		50.20	1051 240.53	0,00	0.01 0.00		0.00	0.00	0.00	0.00	0.00	0.00 0.00		1.13	9.27	0.27	1.39		00.00	7510 0.00	0 0 0 0 0 0 0 0	;
		<u>50.10</u>	1051 240.05	0.00	0.00 0.00	¦e a⊕n≼se	00°0 00'0	0.00	0.00 0.00	0.00	0.00 0.00	0 0.0		1.07	0.25	0.25	1.33		(a'u	7519 6.00	0 0 0 0 0 0 0 0 0 0 0	;
222		0.20				(fer this analysis assume all is	(Input) (Input)	•	(Input) (Input)	(Input) (Input)	,	(Input) (Input)		•							2°54 2°54	
		5 7. 00	1051 279.58	0,.00	0.00 0.00	For this	0.00 0.00	0.00	0.00	0.00	0.00 0.00	0.00		1.02	0.24	n. 24	1.26		ບ່ານ	0127 0.03	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	
E.		Feat Dem(000 Lbs/Hr)) (Net.) Required	til Gals)	al Sequired		(Nil 1445)		Min Annual MW Dutput Avg Min Suemer MW Dutpt	r(Mil (bs)	- Subtotal Arg Btu/Lb(Net) Stean Btus(Bils)	16 Heat Rate Boller Efficiency Coal Rtus Required(Ril)	ter gy (\$Hi []	Subtotal 	aon (Net)	Subtrtal .		5 t CD415	ting fragmired(Pils) Brus keyurred(Pils)	(1)(1)	etter Famgual S	
		Fest Den(Avg Rtu/Lb(Met) Bil Btus Required	Hot Water (Nil Gals)	Avg Btu/Gal Pil Rtus Kequired	ETISTING COGENEFALION	Elect Energy(Mil Luhs) Su on er Fest of Yr	Subtotal	Min Annual MW Putput Avg Min Summer MW Bui	Steam Supply(Mil (bs) Summer Fest of Yr	Swbtotal Avg 8tu/l Stean êt	16 Heat Rate Buller Efficiency Coal Rtus Require	COSTS-Elect Energy(\$Mill On-peak Intermed Dif-peak	Subtotal Incre.clark harod/em.li	Distribution (Net)		TOTAL ELECT COSTS	stre fuel Keds & Costs Uthrout GFC	Eristing fequical feqs Eristing frequences feqs	Rtu/Lb Tatal Tonstilli	€fign (rai \$/Ton (jaettop \$:Ton 2sh Famoua) Totat €(To	
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2.20	2.83	1.46	
2. ng	2.69	1.39	
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TOTAL NON-BFC CASE COSTS

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2.20	1.14	5.05	
2.19	1.09	4.90	
2.19	1.03	4.39 4.51 4.64 4.77 4.90 5.0 5	
2.18	66.0	4.64	
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2.18	0.89 0.94 0.99 1.03 1.09 1.14	4.39	
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Funch Fuels	r # 0	Total Costs	

ENERGY EDETS WITH BFC

6FC A.ailability(Hrs/

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Frice (c.348h)

Min 6FC Annual MM Out Bri Jug Min Summer Na

Total Elect Costs(SM)

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Totat Therm Costs(\$M1

Subtotal GFC En

faristing Cogen Fuel

Supplemental Energy

Elect Energy(Mil JWh Rate (c/JWh) Energy Cost(9M11)

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Fatels/JW/Mo)-12 H Elect Peand-Summer' Fatels/LW/M1) 4 Mo Peand [nst(8M1])

Elect Cast (Bm

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:	n.85	6 8 . v	9.94	66.0	1.03	1.09	1.14		1.20	1.26	1.32	1. 39	1.46	1.53	1.60	1.68	1.77	14.34
	4.28	4.39	4.51	4.64	4.77	4.90	5.05	•	5.31	5.58	5.87	6.17	6.40	6.83	7.18	7,55	7.94	63.96
#C																		
(J. J.)							1096		7096	1096	1096	1096	1596	1596	1596	7596	1246	
(1'4)							15.88		15.91	12,94	15.97	16.01	16.04	16.07	16.10	16.14	16.17	160.23
		Ŧ	Cost of pu	(Cost of purchased electric energy)	lectric e	(Åå Jav	10.76	5.00	11.30	11.86	12.46	13.08	13.73	14.42	15.14	15.90	16.69	16.69
Dutput Ne							10.20 (Input 10.20 (Input	* *	10.20 11.20	10.20 10.20	10.20 10.20	10.20 10.20	10.20 10.20	10.20 10.20	10.20 10.20	10.20 10.20	10.20 10.20	
(1)						1	1.11	•	1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
(Lbs)							187,47 176.01 7.66	5.00	(67.47 176.01 8.04	167.47 176.01 8.44	167.47 176.01 8.86	167.47 176.01 9.31	167.47 176.01 9.77	161.47 176.01 10.26	167.47 176.01 19.78	167.47 176.01 11.31	167.47 176.01 11.88	1,674.66 1,760.06 11.88
(slep							9.00											
							0.00											
('₩							1, 29		1.35	. .	1.48	35.	1.64	1.72	1.80		1.99	16.13
, "osts							2.99	'n	3.14	3.31	3.47	3.65	3.84	4.04	4.24	4.46	4.69	37.83
l Costs							0.0		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0ù°ù	0.00
y Reqs																		
(sund							0.00		0.00	0.00	0.00	0,00	0.00	0.00	00.0	0°0	0.0	0.00
							0.00		0.00	0.00	00°0	0.00	00.0	0.00	0.00	0°0	10.21	0°°ú
(MN) Pr							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	00°0	0.00	
12 110							B. 93		9.38	9.85	10.34	10.85	11.40	11.97	12.57	13.20	13.86	
kor (TW) 1 Ma							0.0		0.00	0,00	9.6 9.6	0.00	0.00	0.0	0.0	0.0 0.3	0.0	
							0.00		0.00	0.0	0.00	. S. O	0.00	0.00	0.00 0	0.00	00'0	0.00
(14)						1	0.00	•	0.00	0.00	0.00	0.0	0.00	00.0	0.0	0.0	0.00	00.0
3									2	:		-	:			:		
1857 181							0.0u		00.00 0.00	0.00	0.0	0.00	0.00	90.04	20.00	0.00	64.47 0.00	0.00
=							64-46		1 5.99	67.43	67.92	69.40	68.89	63.38	69.87	70.17	70.86	686.5?

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	Y	95.75		0.00	0.0	0.00	0.0	000	0.00	95.75	0.69	1.00	1.00		1.09	0.69	0.7B	66.0			2.70	3.47	1.1	7.94		2.70	1.99	4.67	u , n
		95.09		0.0	0.00	0.00	0,00 0	0.00	00.0	95.09	0.67	0.94	0.94		1.04	0.65	9.74	0.95			2.57	3.30	1.68	7.55		2.57	68.1	÷.•	0.00
		94.42		0.00	0°.0	0.00	0.00	00.0	0.00	94.42	0.67	0.89	0.89		0.99	0.61	0.70	0.0			2.44	3.14	1.60	7.18		2.44	1.80	¥. *	UU 'U
		93.76		0.00	0.00	0.0	0.00	0.0	0.00	91.76	0.66	0.84	0.84		94.0	0.59	0.67	0.86			2.32	2.98	1.53	6.83		2. 72	1.72	7. 7	0,00
		93.10		0.00	0.00	0.00	0.0	0.0	0.00	93.10	0.66	0.80	ŋ.80		06.0	0.56	0.64	0.82			2.20	2.83	1.46	6.49		2.20	1.64	18.7	ψυ.,ή
) r		92.44		0.00	0.00	0.00	0.00	0.0	0.00	92.44	0.65	0.75	0.75		0.86	0.53	0.61	0.78			2.09	2.69	1.39	6.17		2.07	1.56	3.45	0.01
		91.78		0.00	0.00	0.00	0.00	0.0	0.00	81.18	0.65	0.71	0.71		0.81	0.51	0.58	0.74			1.99	2.56	1.32	5.87		1.99	1.48	41	0. N
		91.12		0,00	0.00	0.00	0.00	0.0	0.00	91.12	0.64	0.67	0.67		0.78	0.48	0.55	0.71			1.89	2.43	1.26	5.58		1.89	1.41	5	0.(1)
		90.46		0.00	0.00	0.00	0,00	0.0 0.0	0.00	46.46	0.64	0.64	0.64		0.74	0.46	0.53	0.67			1.80	2.3	1.20	5.31		1.80	1.35	3.14	(u° U
												:	1			2	8						i	i				•	•
		8		58	0.00	8	00	ŝŝ	0.00	18	.9. 19	3	. 09.		0.70	0.44	0.50	0.64			1.71	2.20	1.14	5.05		1.71	1.28	2.99	10,0
		8.91		66	5 ¢	ė	é	o e	6	68	••	0.60	0		•	•	•	0.64			-		-			-			
ない		-			_			5			6al s)		Suppl Fuel Cost(\$Mil)		s.			Cost	1.KY	L y				6F C		F MC	Ŧ		Fristing Coopy Coal Costs
k		fuel 8tus Req (Bil)	Mgn-6fC Fuel Regs	leq (Bil)	Coal (000 Tons) Frire (\$/Ton)	Cost (\$Mil)	Ptus Req (Bil)	Wat Gas (Mil Cu Ft)	East (Mil)	([IB) Day	Fuel Oti (Mit Gals)	Frice (\$/5al) Cost (\$Mil)	çel Fuel	t (8Mil)	Site Elect O A	Site Thermal D &	0 k M Savings	Suppl 0 % M Cost	COST/REMERTE SUMMARY	Without GFC Facility	Purch Elect Fwr	s lau		Subtetal-No 6FC	With GFC Facility	furch GFC Elect Fwr	Furch GFf Thereal	Subtotal	na Cogen
		Fuel Øtu	Nan-6f C	Ptus A	Frire	Cost 1	Ptus F	Nat G	Cast	81 15	Fuel (Frice	Sul	0 \$ M Cost (\$Mil)	Site	Site	H H	Sup	COST / PENE	Without E	Purch E	Furch Fuels	H T Ŭ	Sul	Nith GFC	furch l	Furch	19 19	Fristi
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	2° 7° V	0.00	7.85	7.85	8.06	53.74	10.22 48.05		
		0.0	1.00	1.00	6.99	6.35 6.68	1.26		
		0.0	0.94	0.94	0.95		1.20 1.26 5.66 5.95		
		0.00	68° Û	98.0	0.90		1.14		
تىپ مەر		0.0	0.84	0.84	0.86	5.74	1.04 1.09 4.89 5.12		
		0. IN	08°U	(). P()	0.82	5.45	1.04 4.89		
2021 - 1020 - 2021 - 2022 2021 - 2022 - 2022		0.00	0.75	0.75	0.78	5.18	4.64		
•••		0.00	0.71	0.71	0.74	4.93	0.90 0.94 0.99 4.20 4.42 4.64		
		0.00	0.67	0.67	0.71	4.68	0.90 4.20		
Ŵ		0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	0.64 0	0.64	0.67	4.45	0.85 0 4.00 4 1990 MFV at Discrimt Rate of	20.00 1	3.4
		0,00	0.60	0.60	0.64				
				Ū	0.64	4.23	0.81 3.80 Cumulative	Savings	10-Years 10,22
									=
•							DF SAVINGS:		
							FIMAMCIAL EVALUATION OF SAVI		
							FINANCI		
		Fur				Subtetal-Nuth 6FE	5 (8M11) / 6FC		
		Suppl Elect Fwr	Suppl Fuels	Subtotal	¥ 0	Subtatal	NET GFC SAVINES (\$M1]) Avoided cast w/ GFC		

	28.30 Fercent 28.90 Fercent	08.30 28.30	- Fines Equals: Equals:	Cnal fn - Fines Hrly Efficiency Equals: Annual Efficiency Equals:	10.30 (Ernss power out)	In,700.76 Divided by	Fines Bross Heat Rate: 110.22 (Coal einus Steam k Tars)		21,611.34 Divided by	Net Heat Fate: 110.22 (Coal airus S'eam & Tars)
		+ Other 0.00	+ Tars/Dils 0.00	Net Fwr Dut + Steae 123.52 102.06	Re Equals:	+ Other 0.00	+ Tars/Oils 0.00	t + Stean 14.38	Net Pwr Out 17,41	
			1	Annual Calc (bil Btus)	Æ			(mil 8tus)	Hourly Calc	GFC FLANT EFFICIENCY:
		884.15		***********************	124.60		69 .		*****	LOIAL RINS. TOTAL RIUS:
			116.37		Input	Btus/hr	16.40	5 7 5 -		Miscellaneous
			70.25		(Input			41		CO Shift Air Cooler
()			0.00 212.88		<laput (Input</laput 			4 4	ng Tower	Cyclone Carbon Dust Heat Revected by Cooling Tower
-			3.41 13.70 0.00		(Input)	Nil Btus/hr (0.48	ţ		Losses Ash
			Û. Û		(Input (Input	Mil Btus/hr < Mil Btus/hr <	0.00	at at		Other Outputs: Tar=/Dils Otherie.g., Sul,Aeaen)
			123.52		17.41		5.10			Net Far Dut
			(116.25)		(16.39)	₹	(4°B) #	Input >		Aus Fur Regs
-			67.81 0.00 (9.69)		9.56 0.00 (1.37)	ē ž	2.80 MM 0.00 (0.40) MM	Input > Input > Input >	r	Ges Expander Unteut Theraal Mgt System Fower Conditioner Losses
			181.64		25.60	Z	1.50	Input >		Electric im Outout: fiel Cell Cutout
			102.06		14.38	Btus/1b	1044	Input)		Wet Enthalpy Gain:
						13776 000 Lbs/hr	13776	Input>		Steve Uutput: Then Boshr & Lin psia:
	GFC Plant Analysis (Westinghouse Fuel Cell)	~	Bil Ptus/Yr		Mil Rtus/hr					
A.1-1	Fort Greely			58,865.62 199.09	Annual Tons Coal: Tons/ Day:				Hestinghouse Fuel Cell	ENERGY BALANCE SUMMARY

				-	-	~	<i></i>		-	-	-	~ .			۰.)	•
A.1-2																	
Α.,				33.00 (lnput	13.00 (Input 15 (Input		0.00 (Input 0.10 (Input 0.40 (Input										
			89.00 (Input		•••		•	-									
	385	Assumption		20.00	-	_	unt (5K i 1)										
	DWNERSHIP AND FINANCING STRUCTURE	farameter	Fercent Government Funding	Fercent Frivate Funding Fercent equity Percent debt	Interest rate Loan tereiyears)	Constr int rate	Constr loan amount(\$Mil) 1st yr portion 2nd yr portion	Jrd yr portion									
		č	. E E	<i>.</i>							-						
Ň	v	Annual Escal. Rate 1950-2010	5,00	5.00	5.00	¢ ž	8.00 80 80 80 80 80 80 80 80 80 80 80 80 8	5.00					c Rate				
	All Inputs	Energy Frice Annual Es 1990	9.66 10.76 8.93	2 Q2 •	39.00	7,510.00	2.60 34.00 7.44	M.A.			Fercent of Equip 100.00 Percent 0.00 Percent		3.00 Percent Esc Rate				
					~				-			1	_	*			
	All Inputs	Annual Escal. Rate 1980-1990	5.0 8.0 8.0	0.0	0.00	W	6 .00 1 0 1 0 1 0 1 0	2.0	1990-2010	5	5.00 15.00	10.00 Z	0.00 (thru 1999)	50.00 X			
	U	đ	Mtd Avg 0.40 0.60														
	All Inputs	Energy Cost	7.57 HF 8.43 7.00	4.20	39.00	7,510.00	2.60 34.00 6.00	. A.	1985 Existing	ACRS	5.00 15.00	10.00 2	n. 70	50,00 1			
	ECCWOMIC & FINANCIAL Assumfituus Ai	:	GFC Slect En Er tots,Lwh) Displaced Mainwright Sall to GvEA	fuel Dill\$/Mil Rtu)	Coal Frice(\$/Ton)	Coal Heat Content	tera/10/ Coal Frice(\$/Mil.Ptu) Coal Fines Frice (\$/ton) Steam Frice \$ Esc Rate	0 k M Esc Rateit per Yr)		Depreciation Method	Depreciation Term(Years) Equipment Utilities & Other]n⊷estment lax [redit	Monconventional Gas Annual Income Tax Credit (#/Mjl, Btu)	Investor 5 Annual Incore Tar Rate (Cehined Fed. & State)			

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CONSTRUCTION COST SITE: Reexdown (8411)	AK GFC S	GFC SIZE: IL MM				GFC 0 & M COST Decardaniamity				ب	1.7-3		
	5.00 2 Esc Rate 1985s	550 Rate 1985s 1989s	-	Feriod When Costs Will Dccur 1987 1988 1989 198	l Dccur 1989		Escal, Rate:	5.00 X 1985\$	\$0561	1995			
Coal Hndig & Gasıf. Gas Frocessing & Systems	7.90		20.00	0 40. 00	40.00	Direct Labor	0.8ú						•
Fuel Cell/Far Cond. Thermal Mgt Syst. Balarce of Flant	18.40 7.00 2.80		·			Fringes @ 20% Cantract Oper Fee	0.16						
		41 AA E4 P0		1		Contract Maint.	0.22						
				9 71./P	ca .27	Chen & Supplies	0.18						
Fratctype Investment(Incl above) Unique Site Costs	0 U	0.00 0.00	0.00	0.00	0.00	Spare Pts/Maint Sup	p 0.30						
						Water & Site Utils	0.10						
Generai Conditions(Incl above)		0.00 0.00			50	Ash/Sludge Disp.	0.08						
Pacian 1 Envineering (las) shows	-					Mi sce]	0.07						
Freproduction Costsilact above) Contingency at a fercent of:	0.00 0.00	1.41 1.71 0.00 0.00	0.57	0.57	0.00 0.57	Subtotal		2.01	2.56	3.27			
10:AL CONSTRUCTION COST:			-		28.43	Meeting Charge		0.00	0.00	0.00			
puri	ć	0.00 0.00			0.00	Fuel Cell Reloading Costs in 1985t of	32	ŧ	AN AN	0.39			
Other Special	ù.	0.00 0.00 ;	.00		0.00		8/km						-
	4					10141 0 % #		2.01	2.56	3.68			
TOTAL CONSTRUCTION + SFECTAL:	58.71	71 68.74 :		27.10	28.43								-
DTHER CAFITAL COSTS		•			W 15 15 16 16 16 16 16 16 16 16 16 16 16 16 16		£5	0.00	0.00	0.0			<u> </u>
Working Lapital Accts Receivable at Fuel Inventory at Ather Inventory/Supplies	45 days 15 days 0,00	0.55 0.09 0.49		0.00	0.55 0.09 0.49	Insuranc e Prop. Taxes		0.20	0.26 0.00	0. JJ 0. ņņ			-
dr-nts Fayable at	(1985) 10 days	-			(9.14)		ï			41 12 12 12			-
Subtotat Working Capital		66.0	0.00	0.00	0.99	TOTAL OTHER		0.20	0.26	0.33			-
Friv Ein Fees at Percent of: Trif Ety Dwn Fee at Fercent of: Dittor	8.00 z 2.00 z	1.12 0.28		0.00	1.12 0.28								
Subtotal	*	1.67		ĺ	0.28								
TOTAL DIHER CAFITAL COSTS:		2.67			2.67								
SOMSTRUCTION INTEREST:		0° U	0.00	0.00	0.00								•
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In 1994 5 In 1995 5 36.19 38.74 5.10 5.10 5.10 5.10 5.10 5.10 9.66 12.33 0.00 0.00 3.50 4.78 3.50 4.78 12.36 109.25 1.02 06 1.09.25 3.66 9.77	£	In 1995 3.10 5.11 5.11 5.11 12.33 4.75 4.75 104.64 104.64 104.64 104.25 104.64 104.25 11.02 0.30
38.7 5.112 5.112 112.33 4.75 4.76 109.65 109.25 109.25	38.7 5.11 5.11 12.73 4.75 4.76 4.76 104.64 109.25 9.77 9.77 9.77 0.00	38.7 5.1(5.1(12.3) 12.3) 4.7(4.7) 12.30 1.02 1.02 0.30 0.30
38.7 5.11 5.11 12.33 0.00 0.00 4.76 104.64 104.64 109.25 109.25	38.7 5.11 5.11 12.33 0.00 4.78 104.64 104.65 109.25 109.25 1.02 0.00	38.7 5.10 5.11 12.3 4.75 4.76 104.64 104.64 104.64 104.64 109.25 0.30 0.30
5.11 5.11 12.33 0.00 4.76 4.76 104.64 104.64 109.25 109.25	5.11 5.11 12.33 0.00 4.78 4.78 104.64 4.78 104.25 109.25 1.02 0.00	5.10 12.31 12.31 4.75 4.75 104.64 104.64 104.64 104.64 104.64 0.00 0.30
5.1(12.3) 4.75 4.76 4.76 104.64 104.64 109.25 109.25	5.1(12.3) 4.75 4.75 4.76 4.76 4.76 104.64 104.64 1.02 9.77 0.00	5.1(12.3) 4.75 4.77 4.76 104.64 104.64 104.64 104.69 1.02 0.30
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0.00 4.76 104.64 109.25 9.77 1.02	0.00 4.75 104.64 109.25 9.77 9.77 1.02 0.00	0.00 4.16 104.64 109.25 1.02 1.02 0.30 0.30
4.76 104.64 109.25 -77 1.02	4.76 104.64 109.25 -7.7 -1.02 -0.00 0.30	4.78 104.64 109.25 9.77 9.77 1.02 0.30 0.30
104.64 109.25 9.77 1.02	104.64 109.25 9.77 1.02 0.00 0.30	104.64 109.25 9.77 9.77 1.02 0.00 0.30
109.25 9.77 1.02	109.25 9.77 1.02 1.02 0.00	1.09.25 9.77 1.02 0.00 0.30
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COAL GASIFICATION-FUEL CELL-COGENERATION PLANT A1: AK 511E	.L -COGENERA Ak	A110N PL	ANT A1: 511E	μ	EFL CF ANALYSIS	AK SITE		Priv Eqty:		Tot Cap Costs 4.71		71.41 20.00		fercent		- I - V
FTNANCIAL ANALYSIS (\$MIL) Item	Enginee 1987	ring/Con 1388	Engineering/Construction 1987 1988 1989		Operat 1990	.Ö	2651	Priv Debt: Total Private Cap: 1993 1994	te Cap: 1994	9.57 14.28 1995	= 1996	20,00	8591 190.76	Fercent Sc 199 Yr	cent Subtatal 1999 Yrs 1-10	5000
Revenues El attac	000	2	00 0	ï			10 L	20 F		**********	, CO 2		, , , , , , , , , , , , , , , , , , ,			
there is a second second second second second second second second second second second second second second s	00.0		00 0			01 0	20.00				30.0	1.05		16.0		21.0
(ther	0.00	0.0	0.00		0.23	0.25	0.26	0.27	0.29	0.30	0.31	0.33	0.35	0.36	2.95	0.38
- Subtotal	0.00	0.00	0.00	1	4,48	4.70	4.54	5.19	5.45	6.03	6.33	6.65	6.98	7.33	59.09	7.70
atra facto															12.37	
sison builte wa	00 0	00 0	00.0		91 C	11 6	2 51	1 44	01 6	10 6	90 P	1 21	1 10	75 1	70 00	1 7
N 2 0	0.00	00.0	0.00		2.56	2.69	2.82	98-7 96-7	117	2.27	3.43	3.60	82.5	3.97	12.20	
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	6.34	0.36	0.38	0.40	3.21	0.42
- Subtotal	0.00	0.00	0.00	1	5.11	5, 37	5.64	5.92	6.21	6.52	6.85	7.19	7.55	7.93	54.29	8.33
DFERATING CASH FLOW	0. 00	0.00	0.00		(0.63)	(99,0)	(0.70)	(0.73)	(11.0)	(0.49)	(0.52)	(0.54)	(0.57)	(09.0)	(6.20)	(0.63)
Debt Service: Frincipal Interest	0.00		0.00	15 Yrs	0.64	0.64 1.16	0.64 1.08	0.64	0.64	0.64 0.83	0.75	0.66 0.66	0.58	0.64	6.38 8.71	0.64 0.41
Subtofal Coverage Ratio	0.00		0.00 0.00	;	1.88 (0.34)	1.80	1.72 (0.41)	1.63 (0.45)	1.55 (0.49)	1.47	1.38	L. 30 (0.42)	1.22 (0.47)	1.14	15.09	1.05
Debt Svc Reserve Cumul Feserve					0.00	0.00 0.00	0.00	0.00 0.00	0.00	0.00 0.00	0.00	0.00 0.00	0.00 0.00	0.00	0.00 M.A.	0.00
KESIPUAL CASH FLOW	00.0	04.0	0.00		(12.51)	(2.46)	(17.41)	(2.36)	12.32)	(1.96)	(1.90)	(1.84)	(1, 79)	(1.73)	(21.28)	(1,68)
aaj luomabenew	-				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0,00	0.00	0.00	0.00
Tar Adjustaents Pepr 5-yr Equip(SL) at Pepr 15-yr Equip(SL) at	-	(Frivate share of equipment) 20.00 Perci 20.00 Ferci	share ent) Percent) Fercent)		2.61	2.61 0.00	2.61	2.61	2.61 0.00	0.00	0.00	00.0	0.00	0.00	13.06 0.00	0°.0
Amort Startup Lost Frincipal Fayment Debt Svo Reserve	0 0°0	0.00	0.00		0.00	0.64	0.64	0.00	0.64	0.00	0.00	0.00	0.00	0.64 0.00	6.38 0.00	0.64 0.00
° 1arable incrme∕lossi-1	0.00	0.00	0.00	1	(4,49)	(1,41)	(4, 39)	(4.38)	(4.29)	(1.32)	(1.26)	(1.20)	(1.15)	(1.09)	(27.96)	(1.04)
lar Saving of Favent(-)	n.(10 74.00	0.00	0.00		2.24	2.72	2.19	2.17	2.15	0.66	9.63	0.60	0.57	0.55	86.31	0.57
ir sins ias teoir at Syngas iar Eretit at Friv Eapital Requirement Friv Form Folt Financing	9 00.0	0.00 S/Hil Btu (. =		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	Ů. Û	
NET CASH FLOW	0.00	0.00	^	(3.34)	(0.27)	(9.24)	(0.22)	(0, 19)	(0.17)	(1.30)	(1.27)	11.24	(1.21)	(1,18)		(1.16)
irilative Cash Flow	0 0 ,00	0.00	(3, 34)		(3,61)	(3.85)	(4.07)	(4.26)	(4,44)	(2,73)	(1,00)	(8.24)	(6.45)	(10.64)		(11,80)
				÷308	FRRF	FRR Fercent;	≈V?N	ERR	at a	ERR	Fercent Disc Rate.	isc Rate.				

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10 Year Cash Stream

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A. ۶.، <i>ا</i> Fort Creelv	GFC Plart Analysis (UTC Fuel Cell)																•
	1) 040												1,231.95	4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4	+ Other 0.00		79.85 Percent 78.85 Fercent
js/hr of 173.60 (Input	Ril Rtus/Yr		176.01	280.94	62.97 9.69 (14.53)	(42.27)	246.79	0.00	4.97	0.00	249.36	178.1	144.76 ===	Amnual Calc (bil Btus)	+ Steam + Lars/Oils 176.01 0.00	1,087,11 Coal In - Fines	Efficiency Equals: Efficiency Equals:
1,231.87 at Mil Btus/hr of 7,510.00 (input 87,015.02 272.79														Annual Calc (bil Btus)	Net Fwr Dut 246.79	- 0	Hrly Effic
Bil Rtus Coal: Btus/Lb: ual Tons Coal: Tons/ Dave	Mil Btus/hr		24.80	39.59	8.87 1.37 (2.05)	(13.00)	34.78	(Input (Input)	(lonut	(Input	input inout	< Input			•	• • • • • • • • • • • • • • • • • • • •	14.60 14.60
: 11.00 : 7096 (Input Anr		23600 000 Ebs/hr	Rtus/1b	Ŧ	ž ž	NE o	,	Mil Btus/hr Mil Btus/hr	Mil Rtuc/hr	Ril Rtus/hr	Mil Btus/hr Nil Btus/hr	Mil Btus/hr Mil Btus/hr		11 17 17 17 17 17 17 17 17 17 17 17 17 1	+ Other 0.00		lr,191.55 Divided by
Rated Output (MM): Avail(Hrs per Yr):		22600	1051	11.60	2.60 MM 0.40 (0.60) MM	(3.81) MN	10.19	0.0 0.0	0.70	1.30	13.40	25.10	20.40	14 14 14 14 14 14 14 14 14 14 14 14 14 1	+ Tars/0,15 0.00	lnes	Grons Heat Fate: 148.8n (Cnal Prinus Stean E Tars)
Site: AK K. August 19, 1985		Faput v	Input >	Input >	Input > Input > Input >	Input>		at at	<u>.</u>		lower at at		1	táki EFFICIENCY: Hourly Caic lail Rtusi	Net Fwr Out + Steam 34.78 24.80	157,20 [gal In - Fines	14,6/2.20 Divided by 10.19 (Nei Furt
GFC FLANT ANALYSIS Au Energy Primary		Steam Nutput: Took Ths.hr @ 120 psta:	uct fat alpy Galn:	Electric Fwc Outout: Fiel Cell Ditput	Eas Expander Mutput Thermal Mgt System Frwer Conditioner Losses	Arr Regs	Nat Fwr Oil	01tor Outputs: Tars/Orls Etherie.g., Sul <mark>,Ammo</mark> n)	Lasses Ash	Cyclone Carbon Dust	Pear Mejected by Looling Inwer CO Shift Air Cooler	Haaf Statk Loss Miscellaneous	Coal Fines TOTAL RTUT:	SFC FLANT EFFICIENCY: Hou		:	llet Heat Gale: 149 En Ifral alous Steam & Tars)

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CONSTRUCTION COST SITE: Refer down (4441)	AK	GFC STZE:11 NN					6FC 0 & M COST Docarnowicesity				
	5.00	5.00 % Esc Rate 1985\$, 19894	Periad When Costs Will Occur 1987 1988 198	Costs Will 1988	Occur 1989		Escal . Rate:	5.00 X 1985#	1990	1995 \$
Coal Mndig & Gasif.	1.87			20.00	40.00	40.00	Direct Labor	0.BÚ		, , , , ,	
bas Frocessing & bystems Fuel Cell/Far Cond. Thereal Mgt Syst.	22.93 6.91	Save NG Rt-up syst	r-up sys!				Fringes & 20% Contract Oper Fee	0.16 0.10			
Balance of Flant 	•						Contract Maint.	0.22			
Subtotal	-	51.50	60.24 :	11.36	23.85	22.04	Chem & Supplies	0.18			
Frototype investment(inc) above)		0.00	0.00	0.00	0.00	0.00	Spare Pts/Haint Sup	0.30			
SISCE TOSES		17.70	49. * 1	19.7	8.0	6.17	Water & Site Utils	0.10			
		:		:	:	:	Ash/Sludge Disp.	0.08			
General Conditions(Incl above)		0.00		0.00	0.00	0.0	Miscel	0.07			
resign & Engineeringilaci abovel Freproduction Costs(Incl above) Fradisons & Service of	4	00.0 1.74	2. II .	0.00 0.70	8 2 3	8 2 3	Subtotal		2.01	2.56	3.27
conclusions of a reflection of a	no•••		3	8	8	8	Wheeling Charge		0.00	0.00	0.0
Land Multiverienus Juius		0.00	0.00	00.0	0.00	0.00	Fuel Cell Reloading Costs in 19858 of	32	¥	NA	0.60
Other Special		0.00	0.00 :	0.00	00 '0	0.0		8/Aw/yr 			
					•		TOTAL O & M		2.01	2.56	3.87
IDTAL CONSTRUCTION + SFECIAL:		66.71	1.21 :	14.86	30.43	51.92					81 81 81 81 81 81 81 81 81
00/46K CaPITaL COStS		r P P P P P P P P P P P P P P P P P P P	р н			• •	□====0THER ANNUAL EIFENSES Legal/Account.	S	0.00	0.00	0.00
Morting Capital Acts Receivable at Fuel Inventory at Other Inventory/Supplies	8 2	skeb 21 Syeb 21	1.04 0.13 0.10	0.00 0.00 0.00	0.0 0.0 0.00	5.04 6.13 0.10	Insurance Prop. Tares		0.00	0.76 0.00	0.00
Accuts Fayable at	10	10 days	(0.16)	0.0	00°U	(0,14)					
Subtotal Working Capital			=	0.00	0.00	1.1	IDIAL DIAFR		0.20	9.26	0.31
Friv Fin Fees at Fercent of: 3rd ^c ty Own Fee at Fercent of: Other Expenses at Fercent of:	8.01 2 2.61 2 7.61 2		1.75 1.75 0.71	0.00 0.01 0.04	0.00 0.00 0.00	125 0.31 0.31					
Subtotal		•	 88.	UÚ U	6 0'0	1.96					
TDfal OTHER CAFITAL COSIS:		*	2.59	0.00	UU U	2.98					

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OMNERSHIP AND Fimancias Structure	ter As	Fercent Government Funding 80.00	Percent Private Funding Fercent equity Percent debt	Interest rate Loan term(years)	Constr int rate	constr loan amountianil) 1st yr portion 2nd yr mertion	3rd yr partion							
All Inputs	Annual Escal. Rate 1990-2010	5.00	5.00	5.00	en a	490 V	5.00			a t		5.00 Fercent Esc Rate		
I IIV	Energy Price Annu 1990	9.30 10.76 8.93	4.20	39.00	7,510.00	2.60	7.66 M.A.		•	Fercent of Equip 100.00 Percent 0.00 Percent		5.00 Fercer		
All inputs	Annual Escal. Rate 1985-1990	5.00 5.00 5.00	0.00	0.00	W	A M A	5.00	1990-2010	ಶ	5.00 15.00	10.00 1	0.00 (thru 1959)	5n.00 E	
		5 Ntd Avg 3 0.20 0 0.80			6			~ •			1 (-	2	
All Inputs	1985 Energy Cost	7.79 B.43 7.00	4.20	39.00	7,510.00	2.60	6.00 R.A.	1985 Existing	ACRS	5.00 15.00	10.00 1	0.70	50.00 2	
ECOMONIC & FINANCIAL Assumptions		GFC Elect En Fr (cts/lwh) Displaced Mainwright Seil to GVEA	fuel Dil(4/Mil Btu)	Coal Price(\$/Ton)	Coal Heat Content ABuilbi	Coal Frice(\$/Mi].Btu) Coal Fines Frice (\$/ton)	Steam Frice & Esc Rate 0 & M Esc KatelZ per Yr)		Bepreciation Method	Depreciation Term(Years) Equipment Utilities & Other	Investment Tax Eredit	Nonconventional Gas Annual Income Tar Credit 14/11. Ptul	Investor's Annual Incree Las Rate (Crebined Fed. & State)	

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72.31 10.19 10.19 7.29 0.00 0.00 10.10 11.00 10.01 10.01 10.00 11.00 10.01 10.00 11.00 10.00 0.33 0.33	72.31 10.19 10.19 7.29 0.00 0.00 5.27 10.19 10.00 10.00 10.00 0.33 vs 0.33 vs	
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si 176.01 16) 6.00 1.00 1.00 0.33 vsi 0.33 9.40 39.40 2.01 0.20 5.40	si 176.01 16) 6.00 1.00 1.00 0.33 vs 0.33 vs 0.33	
10) 6.00 1.00 1.00 1.00 0.33 vsi 0.33 vsi 0.33	10) 6.00 1.00 1.00 vs: 0.13 vs: 0.13 vs: 0.13 si 1,231.87 si 1,20	
te: 1.00 vs: 0.33 vs: 0.33 92,60 39.60 3.70 2.01 0.20 5.40	1.00 1.00 1.00 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.33 0.00 0.33 0.00 0.33 0.35 0.35 0.35 0.35 0.35 0.35 0.35 0.35 0.35 0.35 0.35	
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s ¹ 1,231.87 1,231.87 82,015.02 82,015.02 39.60 39.60 3.20 3.20 2.01 2.56 0.28 0.28 5.40 6.01	s ¹ 1,2 ³ 1.87 1,2 ³ 1.87 82,015.02 82,015.02 39.00 39.00 1.20 3.20 2.01 2.56 0.26 5.40 6.01	
39.00 39.00 3.70 3.70 2.01 2.56 0.70 0.26 5.40 6.01	39.00 39.00 3.20 3.20 2.01 2.56 0.26 0.26 5.40 6.01	
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3.20 3.20 2.01 2.56 0.28 5.40 6.01	3.20 3.20 2.01 2.56 0.20 0.26 5.40 6.01	
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COML BASIFICATION-FUEL CELL-COSENERATION PLANT AT: AX SITE	L-COGENEI	KATION PL AK	ANT AT: Site	.	SFC CF Anal YSTS	ŧ	11 11 11	Priv Eatur		Tot Cap Costs of 5 20	Costs of	80.20 20.00	ti aps	Darrant		
FINANCIAL AKALYSIS (SHIL)				•		5		Friv Debt:		10.75		50.92 50.92				
Itee	Enginee 1987	ering/Con 1988	Engineering/Construction 1987 1988 1989		Opera 1990	Operating Period 990 1991	1992	Total Private Cap: 1993 1994	ate Cap: 1994	16.04	1996	1491	8641	A 6651 5	Subtotal 1999 Yrs 1-10	3000
Revenues												**	2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2	萨萨特拉萨拉拉萨斯拉斯斯斯特特萨特拉特斯特普	******	
Electric	0.00	0.00			6.72	7.06	7.41	7.78	8.17	9.19	9.65	10.13	10.63	11.17	10°.48	11.72
Ther nal	0.0	0.00			1.28	1.35	F. 1	1.48	1.56	1.64	1.72	1.80	1.89	1.99	16.13	2.09
Other	0.00	0.0	0.0		0.42	0.44	0.46	0.48	0.51	0.53	0.56	0.59	0.62	0.65	5.26	9.69
Subtotal	0.0	6.0 8	0.00	•	8.42	8.85	9.29	9.75	10.24	11.36	11.92	12.52	13.15	13.80	109.30	14.49
Omersting Casts															21.39	
Fuel Fuel	0.00	0.00	0.00		1.70	1.74	151	1.70	1 80	8 .08	87 A	05 1	11	40 W	12 07	16 2
U 2 U	0.0	0.00			2.56	2.69	2.82	2.76	3.11	3.27	3.43	3.60	3.78	3.97	32.20	1.17
Other	0.00	0.00			0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21	0.42
Subtotal	0.00	0.0	0.00	•	6.01	6.31	6.63	6.96	7.31	7.68	9.06	8.46	8.8	9.3I	75.64	9.80
BFERATING CASH FLOW	0.00	0.00	0.00		2.41	2.53	2.66	2.79	2.93	3.68	3.87	4.06	4.26	4,47	33.66	4.70
Debt Service: Principal				15	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	7.16	0.77
Interest	0.0		0.00	Yrs	04.1	1.30	1.21	1.12	1.02	0.93	0.84	0.75	0.65	0.56	87.9	0.47
Subtotal Coverage Ratio	llanstr 0.00	tr Loan 0.00	Interest) 0.00	•	2.11	2.02 1.25	26.1 Br.1	1.85	1.74	1.65 2.23	1.55 2.49	1.46 2.78	1.37 3.11	1.28 3.51	16.94	1.18
Debt Svc Reserve					0.00	0.00	0.0	0.00	0.00	0.00	0.0	0.00	0.0	0.0	0.00	0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.00	N.A.	0.00
RESIDUAL CASH FLOW	0.00	0.00	00 ° ú		0.30	0.51	0.73	0.96	1.19	2.03	2.31	2.60	2.89	3.20	16.72	3.52
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax Adjustments	-	(Private share of equipment)	share ent)													
Depr 5-yr Equip(SL) at		20.00	Fercent}		2.93	2.93	2.93	2.93	2.93						14.67	
Depr 13-yr Equip(SL) at Aeort Startuo Cost	0.0	20.00 0.00	Fercent) 0.00		0.00	0.00	0 .0	0.00	0.0	0.0	0.0	0.00	0.0	0.00	00.0	0.0
frincipal Payment Doht Svr Reserve					0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	7.16	0.72
- []arable]ncree/!ncc{-}	0.0	80	00.0	ſ	100 11	112.11	107 11	11 241	120 17	×	101	12.1	17 1	5		
														5		
Tax Saving or Fayment(-) 10 2 Tay Tay Credit at	8.8	0.00 0.00 20 00 Percenti	0.0		0.96	0.85	0.74	0.63	0.51	((.37)	(1.51)	(1.66)	(1.80)	196'1	(19.41)	(2.12)
Syngas Tax Credit at Friv Capital Requirement Friv Perm Debt Financing	0.00	0.00 \$/Mil Btu	522		0.00	0.00	0.00	0.0	0.00	0.00	0.00	Ū. 00	0.00	0.00	0.00	
NET CASH FLOW	0.00	0°-0	~	(3.75)	1.26	1.36	1.47	1.59	1.70	0.66	0.80	0.94	1.09	1.24	•	1.40
Conclative Cash Flow	0.00	Ū, Ū	(3, 75)		(2.49)	(1.13)	0.35	1.93	3,64	4.30	5.09	6.03	7.12	B. 36		9.76
				= 30Y	12.88	Fercent; 10 v	NPV= ear Cash	NPV= (0.11) Year Cash Stream)	at a	32 .8 9 P	32.88 Percent Disc Rate	ijsc Rate.				

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l age									Page 2 1999		382.23		7.34	69.50	8.42	
			-						8661	-	374.73		6.99	87.75	8.02	481.19 490.81 500.63 510.64 520.85 954.70 1,014.59 1,034.89 1,055.58 1,076.69
			A.''-I						2661		367.39		b.66	86.02	1.64	500.63 1,034.87 1
				po	ysis	lant			9661		360.18		6.34	84.34	1.27	420, B10, 1
				Fort Hood	Site Analysis	w/o GFC Plant			2661		353.12		6.04	82.68	6.93	
				FO	Site	0/M			1991		346.19		5.75	81.06	6.6 0	471.75 975.20
									1 1993		339.41		2.48	19.47	6.28	462.50 956.07
									2661 1	9 9 9 9 9 9	5 332.75		5.22	11.92	5, 98	457,43 537,35
									e 1991		0 326.23		16.4 0	5 76.39	0 2°.70) 444.54) 918.75
			6.26 c/HNH)						Esc Rate 1990-2009		2.00 Inputs		5.00	Inputs 2.00	5.00	5.00
			6.26						0581		319.83		4.73	74.89	5.43	4,15,82 9,10,91 - 336,75
			grid at						8881		313.56		4.51	13.42	5.17	427.28 883.26 1.310.34 1
1	6719 Ccal Btu Content	u ⇒ .	5.00 5.00 (Sold to grid at 5.00						9991		307.41		4.29	86.17	4.92	418, 90 P65, 55 L, 284, 65
erc	7696 (Input	1990 Esc Rate Cost 1990-2010		5.00	5.00	5.00	đN	5.00 5.00 5.00	1991		301.38		6ij . #	70.57	4.65	410.49 848.57 1,259.55
Hours of GFC		-	0 6.26 t) 6.26 n 0.00	0 4.16	0.67	0 N.A.	M	а. 1. 1. 1. 2. 1. 2.	9861 <u>(</u>		1 295.47		3.89	61.19	4.47	394.24 462.63 416.69 418.96 427.28 435.82 816.60 812.32 844.57 65.55 881.26 900.93 1,210.74 1,234.57 1,294.51 1.284.551,310.34 1,356.75
Avail	> 20300 > 105 0	Esc Rate 1985-1990	fa 5.00 1 Input> 5.00	0.00	00.00	0.00	N	9.00 5.00	5861 (0 289.68		1.1	67.83	£.3	
5	ri te August 19, 1985 : Input> : Input>	<u>ب</u> بع ۲	4.90 (Input fm below) 0.00	\$		<u>.</u>	s		Esc Rate 1984 1984-50	1 1 1 1 1 1 1	0 5.00		3 3.00	0 2.00	5.00	2.80 2.80
LYSIS	August ie: b1:	1985 Cost		4.15	0.67	N.A.	5129	rr) A.00 ·r) A.00	1X 1984		Subtotal 284.00		3.53	t) 66.50	4,05	387.90 899.00 1,187.90
cite Encl/RENEFLIS ANALYSIS	6fC Steam Output: Thru 165/hr 0 230 psaa: Wet Enthalpy (Rtus:161:	Total	Cost Furch El Fwrlc/kwh) Cost GFC El Fwrlc/kwh) Electric Demandif/iw/Moh	Naiural Gas(\$/mcf)	Fyel Dilf\$*gal)	E-isting Coyen Coal Price(\$/Ton)	Coal Heat Content (Rtu/161	Coal Frice(\$/Mil.8tu) Steam Pr \$ Esc Rate(%/yr) O & M Esc Rate(% per Yr)	ELECTRIC FONER Demand Mithout GFC	k#H Ancunt (Mil k#h5) On peat Interediate Off-peat	Subtota	KNH Rates(Cts/kwh) Average On-peak Average intermediate Average off-peak	Overall Average Suaner(\$ Mos) Rest of Year	Feak MM Orstribution(12-No Rat)	Fest MX Fate(\$/Iw/Ho) Distribution(\$2 Mos)	THEFRAL EEHAND Steam Pemand(Hil [bc) Symmer (4 Mn)

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13.26 TOTAL NON-GFC EASE COSTS Purch Elect Fower

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ENERGY COSTS NITH GFC

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Frice (c/NM)

Min GFC Annual MW Dutput Total Elect Costs(INil) GFC Avg Min Suemer MW

GFC Steam Furch (Mil Lbs) GFC Steam Btus (Pil)

Hot Water Purch(Mil gals)

Frice (\$/000 Lbs)

Frice (c/ 5al)

lotal There Costs(\$M1])

Subtotal GFC En Costs

Eristing Cogen fuel Costs

Supplemental Energy Regs Abs A/C Fur Displ Elect Energy(Mil Hths)

Energy Cost'\$M1])

Eate (c/HM)

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Ceand Cost (SML)

Elect fact (Mill)

Scop) Steam (Mil [bs) Hot Water (Mil Gals) Thermal Btis (Ril)

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32.00	1,333.27 0.00 1,466.60
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26.03	1,249.41 0.00 1,373.25
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	26.03	8.99	35.02	1.02	36.93	1.00		
	24.30	8.37	32.67	0.97	34.50	0.95		
	22.68	7.80	30.49	0.93	32.22	16.0		
;	21.17	15.1	28.44	989-0	30.10	0.86 0.91 0.95 1.00 1.05 1.10 1.16 1.22 1.28	Discount Rate of 20.00 2	3.48
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FINANCIAL ANALYSIS (TMIL) Itea Itea Revenues Revenues Revenues Cheral C		Rated Dutput (MM): 11 Auril Nac Mar Val.	11.00 Bil Btus Coal: 7084 /12214 Bill Btus (141	1,137.49	at Mil Btus/hr of 160.30	160.30 < Input	A.10 -1	-
15 II 10 II			Annual Tons Coal: Annual Tons Coal: Tons/ Day:			F GFC P	Fort Hood GFC Plant Analysis	tr.
EI 24			Mil Btus/hr		Bil Atus/Yr	_ ;		
EI	Input >	20300 000 Lbs/hr						
Ξ	[nput >	1054 Btus/Ib	21.40		151.83	3		
	[nput>	11.60 MW	39, 59		280.94	-		
_	Input) Input) Input)	2.34 MW 1.28 (0.60) MW	7.99 4.37 (2.05)		56.67 31.00 (14.53)	7. 0 3)		
Interest Aux Pwr Reqs	Input >	(3.52) NN	(12.01)	_	(85.25)	2)		
supresai Coverage Ratio Met Fwr Dut		11.10	37.88		268.83			
Cebt S.c. Reserve Other Outputs: Cuaul Reserve Tars/Oils Other (e.g., Sul,Amoon) ssstimual facus rum	t t	0.00 Mil Btus/hr 0.00 Mil Btus/hr	àr ≮lnput àr ≮lnput		0.0	e		
Ľ	-	;			29-24	-		
	* *	4.12 Ail Btus/hr 0.00 Nil Btus/hr	nr <input hr <input< td=""><td></td><td>0.00</td><td>0 c</td><td></td><td></td></input<></input 		0.00	0 c		
	4	III i			361.90	0		
Cept 3-yr Equip(SL/ at LU Shift Air Looler Cept 15-yr Equip(SL) at HSR6 Stack Loss	* *	13.40 Ail Btus/hr 25.10 Mil Btus/hr			95.09 11.811	e		
	at	Π	< Input		57.05	5		
Frincipal Paywent Debt Svc Reserve IDIAL BTUS:			160.54		1,142.03			
Tarable Income/Loss(-) GFC PLANT EFFICIENCY: Mourly Calc	(ail Rtus)	77 19 19 19 19 19 19 19 19 19 19 19 19 19		Annual Calc (bil Btus)	67 19 19 19 19 19 19 19 19 19 19 19 19 19			
1ar Saving ur Fayment(-) 10 t lar Tar Credit at 2tar tar Eradit at								
rent Ling	Net Fwr Dut + Steam 37,88 21.40	+ lars/0ils + 0t 0.00 0	+ Other 0.00	Net Pwr Dut 268.83	+ Steam + Tars/Oils 151.83 0.00	ls + Other n 0.00		
NET CASH FLON Timelative fact flow	: 3		Equals:					
Net Heat Rate;	12,513.86	Gross Heat Rate: 9,126.40	Û					
<u>t</u> 8.90 Di Tars∣	11.10 (Net Fwr)	10	by 15.22 (Gross power out)	Hr 1 y Annual	Efficiency Equals: Efficiency Equals:	36.98 Fercent 36.98 Fercent	Fer cent Fer cent	

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ECONOMIC & FINANEIAL ASSUMFTIONS				
All	Ail Inputs 1985	All Inputs		All Inputs
	Energy Cost	Annual Escal. Rate 1985-1990	Energy Price 1990	Annual Escal. Rate 1990-2010
GFC Elect En Fr (cts/kwh)	4.90	5.00	6.25	5.00
fuel Dil(\$/Mıt Rtu)	4.20	0.00	4.20	5.00
Coal Frice(\$/Ton)	35.00	0.00	35.00	5.00
Coal Heat Content (Rtu/lb)	6178	MA	6719	M
Coal Price(\$/Mil.Rtu) Steam Price & Esc Rate 0 & M Esc Rate(2 per Yr)	2.60 4.00 M.A.	MA 5.00 5.00	2.60 5.11 M.A.	5.00 5.00
	1985 Existing	1990-2010	- - - - - - - - -	
Pepreciation Method	ACRS	SL		
Depreciation Tera(Years) Equipment Utilities & Other	5.00 15.00	5.00 15.00	Percent of Equip 100.00 0.00	fer cent Fer cent
lavestment Tax Credit	1 00.01	10.00 1		
Monconvertional Gas Annual Income Tax Credit (\$/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 P	5.00 Percent Esc Rate
Investor's Annual Incore Tax Rate (Combined Fed. \$ State)	50.00 2	20°00 1		

DWNERSHIP AND Financing Structure

70.00 (Input	33.00 (Input	13.00 <input 15 <input< th=""><th>13.00 (1mput 0.00 (1mput 0.10 (1mput 0.40 (1mput 0.50 (1mput</th></input<></input 	13.00 (1mput 0.00 (1mput 0.10 (1mput 0.40 (1mput 0.50 (1mput
Percent Government Funding 70.00	Percent Frivate Sunding Percent equity Derront dah	loan tere(years) Loan tere(years)	Constr int rate Constr loan amount(#Mil) 1st yr portion Znd yr portion 3rd yr portion

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Solution Solution	COAL GASIFICATION FUEL CECONSTRUCTION COST Defaynomm (Am.1)		511E: 11	GFC S	GFC SIZE:11 MM				SFC 0 % N COST Refationalisment				
	FINANCIAL GAALYSIS (SHIL)	1 1 14 1 MAR (MAR		5.00 2 Esc 191		Feriod When 1987	Costs Will 1988	0ccur 1989		Escal, Rate:	5.00 7 1985\$		\$5661
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$		-Coal Hndlg & Easif.		8.08		20.00	40.00	40.00	Direct Labor	0.80	•		
$ \begin{array}{ c c c c c c c c c c c c c c c c c c c$	Favenues Electric Therai	Gas Processing & Systems Fuel Cell/Pwr Cond. Ibermal Mgt Syst. Balance of Plank	-	7.52 5.46 3.66					Fringes @ 20% Contract Oper Fee	0.16 0.10			
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$;	0 , 1,	Contract Maint.	0.22			
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	5+BTCTal	n	1010101	ě.			10./0	10.01	Chee & Supplies	0.18			
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Operating Costs			•		:	:	4 4					
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	Fuel D. 7. M	Frototype Investment(Incl above Unique Site Costs, Incl Civil	~	0 r		0.00	0.00	0.00 1.70	Spare fts/Maint Sup				
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	()! her								Water & Site Utils	0.10			
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Si btotal								Ash/Sludge Disp.	80.0			
$ \begin{array}{c ccccccccccccccccccccccccccccccccccc$	FRATTRO FACE FLON	General Conditions(Incl above)		e		0.00	0.00	0.00	Miscel	0.07			
0.00 1.201 0.41 <t< td=""><td></td><td>Design & Engineering(Incl above</td><td>~</td><td>0</td><td></td><td>0.00</td><td>0.00</td><td>0.00</td><td></td><td></td><td></td><td></td><td></td></t<>		Design & Engineering(Incl above	~	0		0.00	0.00	0.00					
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	bt Service: Frincipal Interest	Freproduction Costsilnci abovel Contingency at a Fercent of:				0.00	0.0	0.00	Subtotal		2.01	9C.2	3.21
0.00 0.00	s. ht of s!	TOTAL CONSIDUCTION COST-		9		9.16	18.79	14.71	Wheeling Charge		0.00	0.00	0.0
0.17 0.18 0.29 0.29 0.29 0.29 11.1 0.18 0.29 0.29 0.29 0.20 11.1 0.19 0.29 0.29 0.20 11.1 0.10 0.00 0.00 0.00 11.1 0.10 0.00 0.00 0.00 11.1 0.10 0.00 0.00 0.00 11.1 0.10 0.00 0.00 0.00 11.1 0.10 0.00 0.00 0.00 11.1 0.00 0.00 0.00 0.00 11.1 0.00 0.00 0.00 0.00 11.1 0.00 0.00 0.00 0.00 11.1 0.00 0.00 0.00 0.00 11.17 0.00 0.00 0.00 0.00 11.17 0.00 0.00 0.00 0.00 11.17 0.00 0.00 0.00 0.00 11.17 0.00 0.00 0.00 0.00 11.17 0.00 0.00 0.00 0.00	cites age fait							000	fuel Cell Reloading Costs in 1985 of		đ	A	0 40
No.1 Outer <	joht S.c Resor.e							0. 0		\$/kw/yr	I	i	
III AL III AL III AL III AL III AL III AL III AL III AL III AL III AL IIII AL IIII AL IIII AL IIII AL IIII AL IIII AL IIIII AL IIIIII AL IIIIIII AL IIIIIIIII AL IIIIIIIIIIIIIIIIIIIIIIIIIIIIIIIIIIII				>						1			
I. 1.2 I. 1.2 <thi. 1.2<<="" td=""><td>sidilat cash flow</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>101AL 0 & M</td><td></td><td>2.01</td><td>2.56</td><td>3.8</td></thi.>	sidilat cash flow								101AL 0 & M		2.01	2.56	3.8
45 days 0.00 0.00 0.00 1/4ccount. 0.00 15 days 0.10 0.00 0.00 0.12 1/4ccount. 0.00 15 days 0.10 0.00 0.00 0.12 1/4ccount. 0.00 10 days 0.10 0.00 0.00 0.10 0.00 0.00 10 days 0.10 0.00 0.00 0.10 0.10 0.00 0.00 0.10 0.00 10 days 10.16) 0.00 0.00 0.16 0.76 0.00 0.00 0.76 0.00 0.78 0.00 0.00 0.76 0.20 2.00 T 0.00 0.00 0.76 0.20 2.00 T 0.00 0.00 0.00 0.30 2.00 T 0.00 0.00 0.30 1.17 0.00 0.00 1.17	eej jueestru	TOTAL CONSTRUCTION + SPECIAL:		Ŧ	42 48.53		80.91	20.00	TTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTTT		******		
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45 days 0.70 i 9.00 0.00 0.70 i Prop. Lares 0.00 15 days 0.12 0.00 0.00 0.12 0.00 0.00 15 days 0.10 i 0.00 0.00 0.00 0.10 0.00 10 days 0.10 i 0.00 0.00 i 0.00 0.00 0.00 10 days 0.16 i 0.00 0.00 i 0.00 0.00 0.00 10 days 0.16 i 0.00 i 0.00 i 0.00 i 0.00 0.00 2:00 T 0.18 i 0.00 i 0.00 i 0.00 i 0.00 i 2:00 T 0.00 i 0.00 i 0.00 i 0.00 i 0.00 i 2:00 T 0.00 i 0.00 i 0.00 i 0.00 i 0.00 i 2:00 T 0.00 i 0.00 i 0.00 i 0.00 i 0.00 i 2:00 T 0.00 i 0.00 i 0.00 i 0.00 i 0.00 i 2:00 T 0.00 i 0.00 i 0.00 i 0.00 i 0.0	Cope 15 ye Egnup (SL) a	st st¥nnting Capital							lnsur ance		0.20	0.26	0.3
IS 44y5 0.12 0.00 0.00 0.12 0.10 0.00 0.00 0.10 ID days 10.16 0.00 0.00 10.16 1016 10168 0.76 1 0.00 0.00 0.76 1016 10168 8.00 2 0.00 0.00 0.18 0.20 2.00 1 0.18 0.00 0.00 0.30 2.00 2 0.00 0.00 0.30 2.00 2 0.00 0.00 0.30 2.00 2 0.00 0.00 0.30 2.00 2 0.00 0.00 0.30 0.00 0.00 2.34	Baart Startup fost	Arcts Permisable at		45 days	0.70	0.00	0.00	0.70	Prop. Taxes		0.00	0.00	ē.
ID days IO.16i 0.00 0.00 10.16i 0.00 0.00 0.00 0.00 0.00 0.20 2.24 <	1.1.1.1.2.4 [1.2.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.4.	fuel In.entory at Other Inventory∕Supplies		15 days	0.12	0.00	0.00	0.12 0.10					
0.76 0.00 0.76 0.20 0.26 8.00 Z 0.18 0.00 0.01 18 0.00 2.00 Z 0.10 0.00 0.30 2.00 Z 0.10 0.00 0.30 2.01 Z 0.10 0.00 0.30 2.00 Z 0.10 0.00 0.30 2.01 Z 0.10 0.00 0.30 2.01 Z 0.10 0.00 0.30 2.01 Z 0.10 0.00 0.30 2.04 Z 0.00 0.00 0.30 2.04 Z 0.00 0.00 0.30 1.77 Z 0.00 0.00 1.77	.able lncree/loss()			ID days	(0.16)	0.00	0.00	(91.0)		8			
B.00 Z 1.18 0.00 0.00 2.00 Z 0.30 0.00 0.00 Z.00 Z 0.30 0.00 0.00 2.01 Z 0.30 0.00 1.77 0.00 0.00 2.54 1 0.00 0.00	Saving or faveent(-)	Subtotal Wor			0.76	0.0	0.00	0.76	TOTAL DIHER	1	0.20	0.26	N.0
B. (n 1 1.18 1 0.00 0.00 2. (n 1 0.30 0.30 1 0.00 2. (n 1 0.30 0.30 0.00 1. (1 0.00 0.00 1. 77 1 0. (0 0.00 2. 54 1 0. (0 0.0)	tin. Ta Crodit at	-											
2.00 X 0.30 0.00 0.00 2.00 X 0.30 0.00 0.00 1.77 1 0.00 0.00 2.54 1 0.09 0.00	rgas la Ereditat 5 - 5 - 5	Friv Fin Fees at Fercent of:		8.00 Z	1.18	0.00	0.00	1.18					
Subtotal 1.77 : 0.00 0.00 Total Diker Cartial COSIS: 2.54 : 0.00 0.00 CONSTRUCTION INTEREST: 0.00 0.00	is form ("abt from the second of the second	and the Expenses at Fercent of: Dither Expenses at Fercent of:		7-00-7 2-00-1	0.30	0.00	0.00	0.30					
TOTAL DIMER CAFTTAL CUSIS: 2.54 1 0.00 0.00 CONSTRUCTION INTEREST: 0.00 0.00	מני נענא נוֹעא	Subtotat			1.77	0.00	0.00	1.11					
0°.00 0°.00	arljs,sE3 arljefnerj	TOTAL DIHER CAFITAL COSIS:	1		2.54	00.0	0.0)	2.54					
		CONSTRUCTION INTEREST:			00.0	ÛU'Û	0.00	0.00					

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COAL GASIFICATION-FUEL CE	ENERGY FRODUCTION	1n 1985 \$	\$ 0561 uI	1 395 A			A. 10 -	÷			
rlanklipt martsis (fall) Ne Iten fo	Net Ameint of Electric Fawer Sold										
-		78.17	78.11	84.32							
-	Avg Monthly Nar. MW	11.10	11.10	11.10							
~	Arg Monthly Min. MW	11.10	11.10	11.10							
u.	Price(cts/kwh)	4.50	6. 25	84.7							
	Price/FW/Mo	0.00	ŪŪ . ŪŪ	0.00							
-1 -	Annual Energy Revenues (1 Mil)	3.86	£6.4	6.13							
	Annual Capacity Revenues (\$ Nil)	0.00	0.00	0.00							
frincipal Interest Si	 Subtotal Elect Revs Strae/Hot Water Scid	3.86	4.93	6.73							
, a	Aegunt (Kil bs)	144.05	144.05	154.20							
ū	Energy Content(Bil Rtus)	151.83	151.83	162.53							
u.	frice per Unit (\$/000 lb)	4.00	5.11	6.52							•
	îhersal Revenues	0.59	0.74	1.00							-
D	Other Revenues: Esc Rate:		(Tars Based on MA of retail fuel oil price)	NA percen 1 ail price)	-						
2epr 5 /r Equip(561) atte Dopr 15 vr Equip(561) at5 Gwort Startup foet Ax	Pepr 5 rrfqmap/Skl atfars/Offs Dopr 15 vrEquip/Skl atSulfur Georf Startup Fret - Aamonium Sulfate	0.00 0.00 0.00	0.00 0.00 0.00	0.00 0.00 0.00							~
	Other Feys;	0.00	0.00	0.00							-
19. [التعمير المراجع المراجع المراجع المراجع المراجع المراجع المراجع المراجع المراجع المراجع المراجع المراجع ا	GrC total Revs (\$Mil)	4.41	5.66	1.73							(
Jar Saung or Fassenfel Fu In X Inv Taa Greet at a Sense Taa Greet at En Ent. Expital Requiresent An Eri. Ern Ebh Financing Cri. Ferm Ebh Financing Cri	Tar Saung or Kaysenti-) fuel Use In 3 Inv Tar Gredit at	1,137,49 84,647,19	1,137.45 84,547.16	1,137,49 84,647,18							~ ·
	Fuel Enst(\$/ton)	35.00	¥5.00	44.67							*
	Tetal Fuel Cost(1 ML)	2.96	2.56	3.78							-
Ľ	g t R Casts	2.01	2.56	1.87							~
÷0	Other Annual Easts	0.20	11.26	0.33)
ŧ	rft gref COSTS (†441)	·	5, 78	85.1							

1.13 0.68 (0.76) 8.59 1.28 1.91 0.42 10.18 (0.31) 0.68 0.00 0.00 (1.44) 0.00 0.00 0.38 2000 -----9.87 A. 10 . 5 (18.18) 64.40 9.62 0.00 76.02 (2.00) 6.84 9.34 16.18 (0.12) 0.00 13.58 0.00 (24.92) 37.26 0.0 **6.84** 0.00 12.46 0.00 1999 Yrs 1-10 74.02 3.21 N.A. Subtotal (0.83) 1.22 (1.52) (0.30) tiees 33.00 Fercent 8.18 1.22 0.00 4.60 4.71 0.40 9.70 0.53 0.00 0.00 9.0 0 0.00 0.00 0.42 9.40 9.0 8 67.00 Fercent (1.59) (16.0) 1.31 1998 7.79 1.16 0.00 4.38 4.48 0.38 (0.28) 0.68 0.0 9.0 8 0.00 0.68 0.45 8.95 9.24 0.00 0.0 1.40 (0.98) (0.27) (1.67) 51.07 39.00 30.00 7.42 8.53 4.17 0.36 8.8 0.71 0.0 8.0 0.0 0.0 0.68 0.49 0.S 1997 lot Cap Costs of 5.06 = 10.26 = (1.74) (90-1) (0.17) 7.07 (0,261 0.68 0.80 0.08 1996 8.12 3.97 8.38 1.48 0.00 0.00 0.0 0 0.00 0.53 0.0 (1.13) (0, 24) 1.57 (0.16) (1.82) 6.73 0.00 3.78 0.69 0.68 5661 1.73 7.58 8°. 0.0 o.0 0.00 0.9 0.57 (3.84) (0.14) 1.66 (0.09) (08.1) 5.99 3.40 0.68 2.72 0.68 6.88 7.02 0.00 0.0 0.0 8 1.92 0.00 1994 ļ Friv Eqty: Friv Debt: (0.14) 1.75 (1.87) (1.92) 1993 5.70 0.00 3.43 2.96 0.30 6.69 0.68 1.07 8.0 2.72 6.55 0.0 8.0 0.68 0.00 1.96 0.00 (0.13) (0.07) (1.97) (00.4) 2661 0.00 3.27 2.82 0.28 0.68 1.16 2.72 0.68 5.43 6.37 1.84 0.00 0.00 0.0 2.00 0.00 6.24 ł 3115 3115 Operating Feriod 1590 1991 (0.12) (2.05) (90.0) (80.4) 5.17 0.00 5.94 3.11 0.27 6.07 0.68 1.93 °.0 0.0 0.0 2.72 0.00 2.04 0.0 (4.17) (0.12) 2.02 (2.14) GFC CF ANALYSIS 16.1 2.96 2.56 0.26 0.68 0.00 2.72 0.00 0.68 0.00 Ì 5.66 5.78 0.00 0.00 2.08 0.00 ł ł 5 S 30.00 Percent) 30.00 Percent) (15, 32) 0.8 00.0 10.26 Ē 1.1 0.00 0.30 0.70 0.00 **1** n. no \$. #1] Ftu to 1999) З о ۰. م 0.00 0.00 Interesti 0.0 0.0 0.0 7 . NT . P. (Frivate share of equipment) -1 0.00 0.00 0,00 0. ið U. U Ę 99 ŝ 5 0.00 0. U 0. d 0.0 iConstr toan 10, 10 Farcent) 7 2 지 문 ω. 0.95 0.00 0.00 0.0 0.64 0.00 8.0 0. Q 0.0 0.0 Tepr 5 yr Equip(St) at Depr 5-yr Equip(St) at Levr 15 yr Equip(St) at Depr 15-yr Equip(St) at las Gastrig or Fasebootts! Las Saving or Payaentist ניו. דברה (ממל לוהתהרוים ליוע למרת לפלל לוחתהנותם frames of the Service: Frincipal fris Cottal Squireart fris Capital Fequirement Interest Tarable Income/Local 1 10 Z Inv Tax Credit at 1 Sengas Tax Eredit at Aport Startup Cost Frincipal Favment AUTE HEAD BALTANET Debt Svc Reserve Debt Svc Reserve RESIDUAL CASH FLOW Coverage Ratio Tax Adrustments Same Cumul Reserve Manageeent Fee Ubiotal Subtotal ÷ • ÷ ē 1.2 [n. Is Crodit at Interest

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NFV= ERR Year Cash Stream¹ Fercent; ٤ 5 ر (بدا ساط ۲

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EFR Fercent Disc Fale.

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