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PREFEASIBILITY STUDY

OIL SHALE UTILIZATION FOR POWER PRODUCTION IN THE HASHEMITE KINGDOM OF JORDAN

VOLUME I OF VI
EXECUTIVE SUMMARY & STUDY REPORT

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Through the cooperative team effort of this large number of diverse organizations we have developed this prefeasibility study of the technical and economic viability for a new industrial undertaking in the Hashemite Kingdom of Jordan.

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JORDAN OIL SHALE TO POWER
PREFEASIBILITY STUDY

VOLUME I - STUDY REPORT

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PREFEASIBILITY STUDY

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Section 1
Executive Summary

Section 1

EXECUTIVE SUMMARY

1.1 BACKGROUND

With appropriate technology, oil shale offers great promise as one of the undeveloped indigenous fossil fuels resources that can support the growing energy needs of a number of countries. Oil shales are widely distributed throughout the world with known deposits in every continent. For example, Jordan, Morocco, China, Zaire, Thailand, Burma, Turkey, Brazil, and Uruguay are endowed with promising oil shale resources.

Oil shale resources in such developing countries, that can be made to yield oil or alternatively can be burned in direct combustion power plants, are estimated to be 11,000 billion barrels of oil equivalent, an amount equal to 200 years of the current total world consumption of petroleum.

Key to successfully exploiting the oil shale energy potential in the LDCs is use of appropriate technology that meets technical, economic, and institutional requirements. Until recently, such technology has not been available. For example, burning shale directly in conventional power plants has encountered environmental problems and efficiency penalties.

However, use of unconventional direct burning technologies, such as fluidized-bed combustion (FBC), could become attractive alternatives. In the last decade, successful commercial experience with FBC facilities has been accumulating in many countries. Another important development is the growing experience with a second generation of this technology -- circulating fluidized-bed combustion (CFBC) -- that offers improved performance over earlier designs.

These developments suggested that a study effort would be appropriate to assess the feasibility of applying this technology to certain countries that

are overly dependent on imported petroleum for electricity generation, but which possess indigenous deposits of low-grade fossil fuels such as oil shale, tar sands, low rank coals, and biomass.

In 1986, a series of factors related to the Hashemite Kingdom of Jordan's economic growth rate, expanding energy requirements, and lack of available energy resources supported the idea of a USAID evaluation of an oil shale project in the country. For example, between 1975 and the early 1980s, the consumption of electricity in Jordan increased at an average annual rate of about 19 percent, resulting in a coefficient of electricity consumption to GDP of about 1.6.

The rate of growth of electricity consumption in Jordan over this period was high principally because of the commissioning of several large energy consuming industries and the expansion of some of the existing energy-intensive industries such as: cement, phosphate, potash, and the Zarga refinery; and the increase in the proportion of the population with access to publicly supplied electricity -- from 39 percent in 1975 to 67 percent in 1980 -- as a result of the Government's intensified program for rural electrification. By the end of 1993, upon completion of the Jordan Electricity Authority's national plan for extending publicly supplied electricity to rural areas, almost all the rural population will have access to the public power supply.

Jordan is dependent on imports of crude oil and petroleum products for virtually all its energy needs. This is a significant foreign exchange drain on Jordan's economy. As recently as 1983, Jordan was totally dependent upon imported crude oil through the Tapline from Saudi Arabia. In 1984, Jordan began to import crude and fuel oil as part of a counterpurchase agreement with Iraq. As a result Jordan was able to bring about an important diversification in both the type and source of its energy imports. This trend towards greater diversification will further improve with the planned use of recently discovered indigenous gas in several gas turbine generators currently being installed at Risha in eastern Jordan, and use of imported coal for a future new power plant that may be built at the Aqaba thermal power station. Should

phase two of the Aqaba thermal power station program be completed, Jordan will begin importing one half million tons of bituminous coal per year, thereby allowing the country to reduce its dependence on expensive crude and fuel oil imports. Jordan currently exports large amounts of phosphates to a number of coal exporting countries, such as Poland and Australia. The Jordan Phosphate Mining Company (JPMC) also expects to have several million tons of additional export capacity with the opening of its Eshidiya Mine. To the extent that Jordan can enter into counterpurchase agreements with these countries, Jordan can exchange phosphates for coal without the expenditure of foreign exchange.

However, even with estimated future electricity load growth down to "only" 4 percent to 6 percent per year, there are limits to the amount of national energy independence that can be attained by substitution of imported coal for imported oil, and the use of countertrade for the acquisition of coal. In addition, gas reserves may prove be fairly limited. Other indigenous renewable energy sources such as solar, wind and biomass can also make a contribution, but these will be limited, and suitable only for special situations.

Thus, despite the importance of diversification, diversification by itself does not significantly further energy independence. In fact, in 1987, even with depressed oil prices, $360 million were spent on imported energy. This fuel bill has been one of the major reasons for the deterioration in the country's economic performance over the last several years. The next oil price increase could have a serious impact on the Jordan economy. It is therefore critical for Jordan to look to oil shale, its only major proven indigenous energy source as fuel for its future power needs. Recently discovered gas has yet to be proven in quantities sufficient to alleviate Jordanian concerns for its future energy supply and its dependence on imported fuels.

Extensive studies by the U.S. Geological Survey, the Government of Jordan, and several other governments have indicated large reserves of oil shale in Jordan with shallow overburden cover that can be exploited, given the economic stimulus, appropriate technology and political decisions required to develop the resource.

The basic driving forces favoring an oil shale to power development in Jordan are:

- A strategically secure national energy source.
- A project that fits well into the Jordan Electricity Authority's plans for future power supply, with possible private sector participation in financing and operation.
- Foreign exchange expenditures for imported oil and coal fuels presently being used or forecast can be reduced.
- Oil shale as a fuel for power generation has the potential of being a lower cost fuel, especially if oil prices increase from current depressed levels, -- a high probability over the long term.
- The project will create a large new industrial component for the Jordan economy, employing over a thousand workers at attractive wages.
- The project can make use of available underutilized equipment, and experienced mining personnel from nearby phosphate mining operations.

With the above as background, the A.I.D. Office of Energy/Bureau of Science and Technology sponsored a brief consultation visit to Jordan by a team of specialists in April 1986. The objective of the visit was to conduct a preliminary assessment of the concept of direct combustion of oil shale for electric power production in Jordan and to identify any "fatal flaws" that were immediately apparent. The team confirmed Jordanian Government interest and support, verified the promising technical and economic conditions, and recommended an action plan for proceeding with a site specific evaluation.

After extensive review and discussion of the consultation visit results, a decision was made in 1987 by USAID/Amman, the Jordan Electric Authority, and the A.I.D. Office of Energy to jointly sponsor a prefeasibility study aimed at assessing the technical and economic prospects for an oil shale power generation project in Jordan.

1.2 SUMMARY

Bechtel, under the A.I.D. Conventional Energy Technical Assistance (CETA) Project, functioned as project manager for this Prefeasibility Study. Bechtel also created conceptual designs for all balance-of-plant (BOP) facilities beyond the boiler and developed the estimated capital and operating costs for all of the integrated project facilities, including the mine and raw shale processing facilities. JEA/NRA provided the resource assessment; the design basis criteria for the Sultani site; costs for the 2x130 MW Aqaba I oil fired power station; and the 75 ton sample of oilshale used in pilot plant test program. Pyropower Corporation conducted the pilot test work which established the technical feasibility of burning Sultani oilshale. Pyropower also created conceptual boiler designs for the 20 MW and 50 MW installations plus factored costs estimates for the 100 MW commercial scale sized units. Oak Ridge National Labortory (ORNL) in an oversight role provided a review of forecasted power demand growth in Jordan and an assessment of existing power generation capacity. ORNL also performed an evaluation of environmental considerations for the integrated project. ORNL also developed a separate economic assessment for the three project alternatives under consideration.

Bechtel assembled all of these contributions into a 6 volume report organized as indicated in the Table of Contents.

Pyropower Corporation (Ahlstrom) carried out a 2 week pilot test program at the Ahlstrom Pyroflow fluid bed combustion facilities in Finland. The 75 ton sample of Sultani oil shale provided by the Jordan National Resources Authority was used for this purpose. The test results were quite favorable and show that 2250 BTU/lb oil shale can be burned under stable conditions with low $SO_2/NO_x/CO$ emissions. From this test work it was concluded that the use of Sultani oil shale as a boiler fuel is technically feasible.

Conceptual designs and costs for three size operations were prepared - 20 MW/50 MW/4X100 MW. The integrated facilities included:

- Mining
- Shale Processing (crushing and blending)

- Boiler Plant
- Power Generation + Auxillaries
- Spent Shale Ash and Mine Overburden Disposal
- On-Site Infrastructure
- Off-Site Infrastructure (housing and community facilities)

In the 400 MW (4X100 MW) case the power generation and auxilliary facilities were handled by factored estimates only.

Key results from this work are summarized on Table 1-1. Conceptual estimated costs for these integrated project facilities are presented in Table 1-2.

The differing interest rates on debt and rates of return on equity portions of the project investing costs reflect historical policies relating to Mining and Power ventures. The logic behind these rates is as follows:

- Mining - tends to be a higher risk undertaking due to variations in resource deposition, equipment obsolescence, commodity price changes, etc.
- Power Block - tends to be a lower risk undertaking. The rates employed here are those suggested by EPRI for USA power plant studies.

Figure 1-1 shows how the power block investment cost (65-75 percent of integrated project) declines with size of operations. There is little chance that a 20 MW size project can stand on its own feet without substantial subsidy from JEA. The four 100 MW units are in a competitive cost range.

The economic analysis presented in Section 8 indicates that a "commercial scale" oilshale project will provide favorable 25 year cumulative net benefits compared to a new power project fueled with imported coal.

Table 1-1

SUMMARY OF SHALE PROJECT CHARACTERISTICS FOR THREE PROJECT SIZES

Project Size	20 MW	50 MW	400 MW (4X100)
o Mine Development Excavation Bank Cubic Metres	500,000	1,000,000	8,455,000
o Fuel Consumption, Tonnes/Yr.	390,000	973,000	7,783,000
o Spent Ash Disposal Rate (Wetted) Tonnes/Yr.	327,000	815,000	6,127,000
o Water Requirement, 1000 M^3/Yr.	538	907	1,263
o Net Power Production, 10^6 KWH/Yr.			
- Total Power Generation	158.7	398.8	(3234.5)*
- Power Block Operating Consumption	24.0	60.4	(483.5)*
- Power Used for Shale Mining and Shale Processing	7.2	7.4	123.0
- Net Power to National Grid	127.5	331.0	2628.0
(MW)	19.4	50.4	400.0
o Integrated Project Staffing Requirement, Persons	185	324	1,046
o Community Population	700	1,200	4,000

*Factored Estimate

Table 1-2

SUMMARY OF TOTAL ESTIMATED COSTS FOR INTEGRATED PROJECTS

Project Size	20 MW	50 MW	400 MW (4X100)
Installed Capital Cost, US $1000			
Mine and Shale Processing	$ 27,869	$ 35,115	$ 187,239
Power Block	67,700	112,200	760,500
Waste Disposal	1,618	2,315	8,472
Community Facilities	10,000	15,000	45,000
Total	$107,287	$164,630	$1,001,211
Fuel Cost, US $/Tonne			
50/50 Debit/Equity	17.50	13.48	7.76
80/20 Debit/Equity	14.31	11.8	6.84
Cost of Power, Mill/Kwh			
50/50 Debt/Equity[a]	146	102	78
80/20 Debt/Equity[a]	128	92	71

(a) Includes capital charges computed as follows:

- o Mining and Shale Processing - 10 percent on Debt and 20 percent on Equity
- o Power Block - 9 percent on Debt and 13.5 percent on Equity.
- o Infrastructure - assumed self liquidating

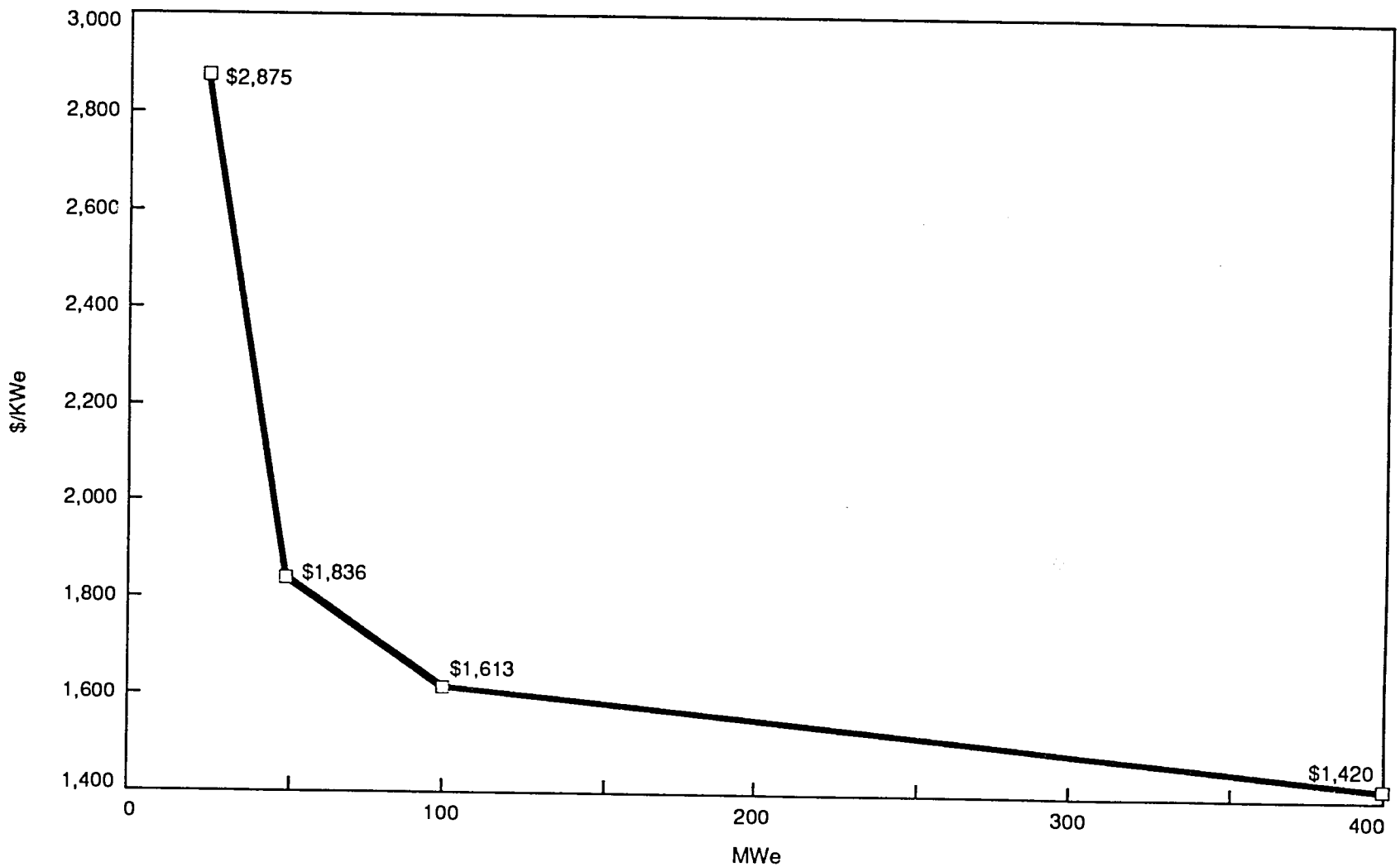

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Figure 1-1 Power Block Investment Cost per Kilowatt as a Function of Plant Size (excluding mining, shale processing and offsite)

Four scenarios are examined covering two project financing alternatives and two levels of future imported fuels costs:

Project Financing - Debt/Equity Ratio

80/20
50/50

Import Fuels Costs	
Coal, $/per ton	Oil, $/per ton
50	120 (17 $/Bbl)
70	170 (24 $/Bbl)

These fuel price levels fall within the range of market values forecasted for years 1995 to 2000 when the Jordan oilshale venture would commence.

Table 1-3 is a comparison of Jordan's future electric power options developed in this study.

The study shows that an incremental investment of $400 million for a 400 MW oilshale project compared to a coal fueled power project would result is a 25 year cumulative net benefit of $2.5 billion with 80/20 debt-equity financing structure when imported fuel costs reach the higher values cited above. The equivalent benefit vs. an oil fired power project is lower: $1.8 billion benefit for an incremental $600 million investment.

The estimated cost of power generation for an oilshale fueled project also compares favorably with coal and oil options (Figure 1-2):

	Mills/Kwh
Oilshale	71
Coal	78
Oil	67

The study indicates that current coal and crude oil prices only need to increase modestly to about $55/tonne and $20/barrel for an oilshale project to have a reasonable payout of the incremental investment involved. This is a reasonable expectation for the time frame under consideration for the Jordan oilshale to power development program.

Factors that have not been dealt with in the economic evaluation are credits for:

Table 1-3

COMPARISON OF JORDAN'S FUEL OPTIONS FOR FUTURE ELECTRIC POWER
BASIS: 400 MWe PROJECT WITH STARTUP IN 1995

Scenario Variables	Scenario No. 1			Scenario No. 2			Scenario No. 3			Scenario No. 4		
Imported Coal Price Imported Oil Price Project Financial Structure-Debt/Equity Ratio	$50/ton $17/bbl ($120/ton) 80/20			$50/ton $17/bbl ($120/ton) 50/50			$70/ton $24/bbl ($170/ton) 80/20			$70/ton $24/bbl ($170/ton) 50/50		
	Imported		Indigenous	Imported		Indigenous	Imported		Indigenous	Imported		Indigenous
Project Inputs	Coal	Oil	Oilshale	Coal	Oil	Oilshale	Coal	Oil	Oilshale	Coal	Oil	Oilshale
Capital Cost — $ Millions												
Mine & Shale Processing	$0	$0	$202	$0	$0	$187	$0	$0	$202	$0	$0	$187
Power Block	$620	$443	$760	$620	$443	$760	$620	$443	$760	$620	$443	$760
Community Facilities	$27	$20	$45	$27	$20	$45	$27	$20	$45	$27	$20	$45
Total	$647	$463	$1,007	$647	$463	$992	$647	$463	$1,007	$647	$463	$992
Operating & Maintenance Cost (Including fuel) for Power Plant Only — $ Millions/Yr.												
1st Year [From Table]	$178 [8.4]	$147 [8.6]	$187 [8.4]	$187 [8.2]	$153 [8.8]	$205 [8.2]	$206 [8.3]	$177 [8.5]	$187 [8.3]	$215 [8.1]	$183 [8.7]	$205 [8.1]
25 Year Levelized [From Table]	$231 [8.12]	$200 [8.14]	$218 [8.12]	$233 [8.10]	$200 [8.16]	$236 [8.10]	$282 [8.11]	$254 [8.13]	$218 [8.11]	$282 [8.9]	$252 [8.15]	$236 [8.9]
Oilshale Costs — Mined & Processed $ per Ton			$6.84			$7.76			$6.84			$7.76
Employment	637	459	1,046	637	459	1,046	637	459	1,046	637	459	1,046
Project Outputs												
Net Power to National Grid-Million KWh/Yr	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628
Cost of Electricity in U.S. Mills/KWh												
1st Year [From Table]	68 [8.4]	56 [8.6]	71 [8.4]	71 [8.2]	58 [8.8]	78 [8.2]	78 [8.3]	67 [8.5]	71 [8.3]	82 [8.1]	70 [8.7]	78 [8.1]
25 Year Levelized [From Table]	88 [8.12]	76 [8.14]	83 [8.12]	89 [8.10]	76 [8.16]	90 [8.10]	107 [8.11]	96 [8.13]	83 [8.11]	107 [8.9]	96 [8.15]	90 [8.9]
Cumulative Favorable Cash Flow from Oil Shale Option:												
Compared to Coal — $ Million over 25 Years	—	—	$778	—	—	$315	—	—	$2,531	—	—	$2,068
Compared to Oil — $ Million over 25 Years	—	—	($18)	—	—	($506)	—	—	$1,810	—	—	$1,322

Assumptions: Inflation = 6%/yr; coal and oil real escalation = 0.8%/yr; capacity factor = 75%; coal and oil borrowed cost = 10%/yr.

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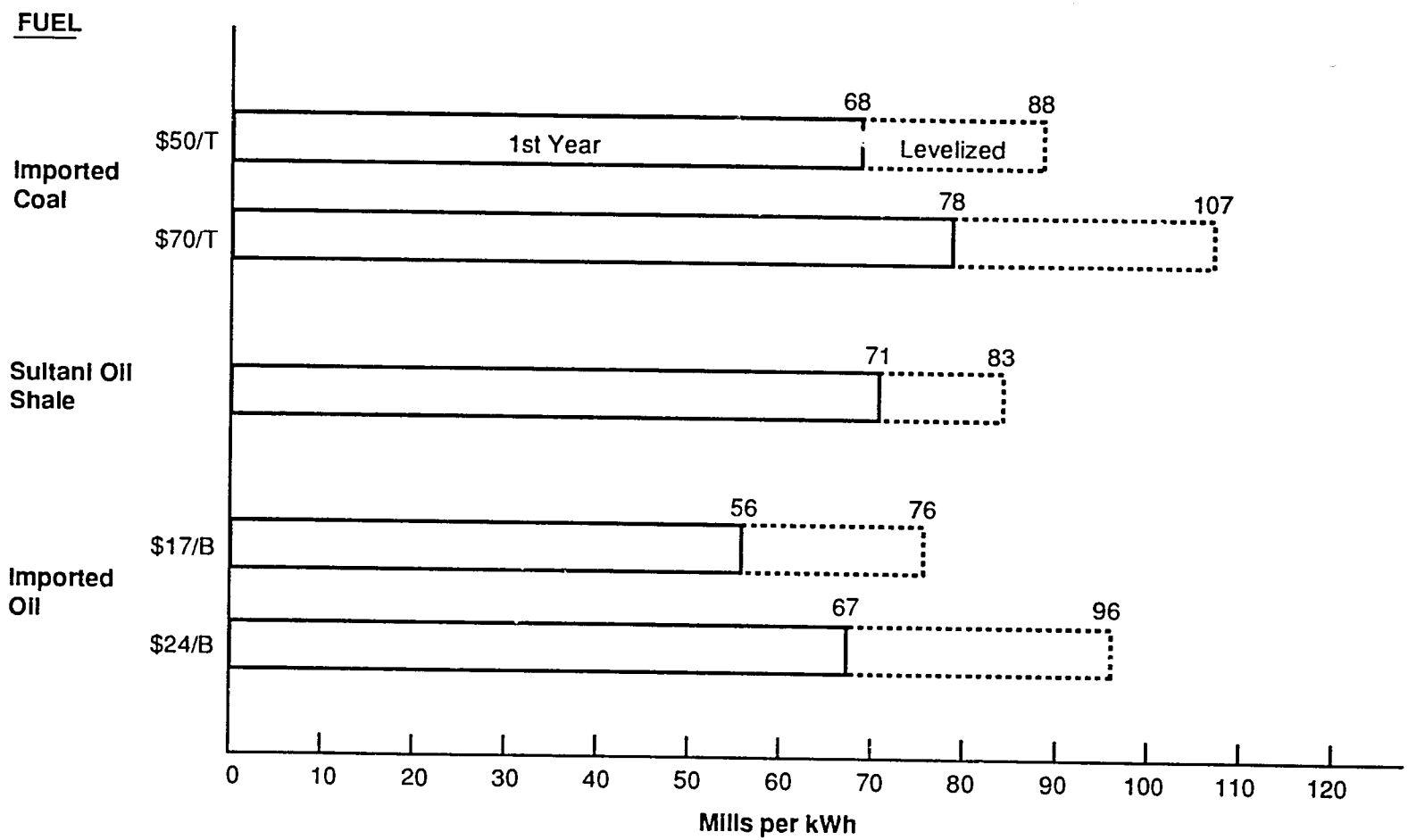

Figure 1-2 Estimated Busbar Power Costs
Basis: 400MW (4x100) New Plant

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- Benefits from reducing annual foreign exchange losses for purchase of oil or coal fuels for alternative conventional power plants.
- Recovery of underlying by-product phosphates.
- GNP growth due to creation of a new industry in Jordan with over 1000 permanent employees.

No environmental constraints appear to prevent development of an oil shale fueled power project at the Sultani deposit.

ORNL's review of the Jordan electric power demand and supply situation through year 2005 indicates a need for 500 to 1500 MW of incremental new generating capacity depending on forecasts of future demand growth. Demand growth is seen to range 4 to 6 percent annually. While the economic analysis prepared in this study is somewhat arbitrarily based on a 400 MW size project, the forecasted demand growth may require two such projects at Sultani (see Figure 1-3). Future planning and definitive studies should consider this option.

Economics for a commercial scale oilshale fueled power project appear promising enough to warrant continued development of a full scale Feasibility Study involving preparation of definitive designs, budget grade cost estimates and project development schedules. It is anticipated that this next step will cost several million dollars and that at least a year to 18 month elapsed time will be required.

1.3 CONCLUSIONS

The results of the Prefeasibility Study indicate that development of Jordan's oil shale resource at the Sultani deposit to provide fuel for power generation is both technically and economically viable under certain conditions.

These conditions include:

- A commercial scale shale power project commencing in 1995 with operations extending to year 2020 and beyond. A prototype shale project would precede this commercial development.

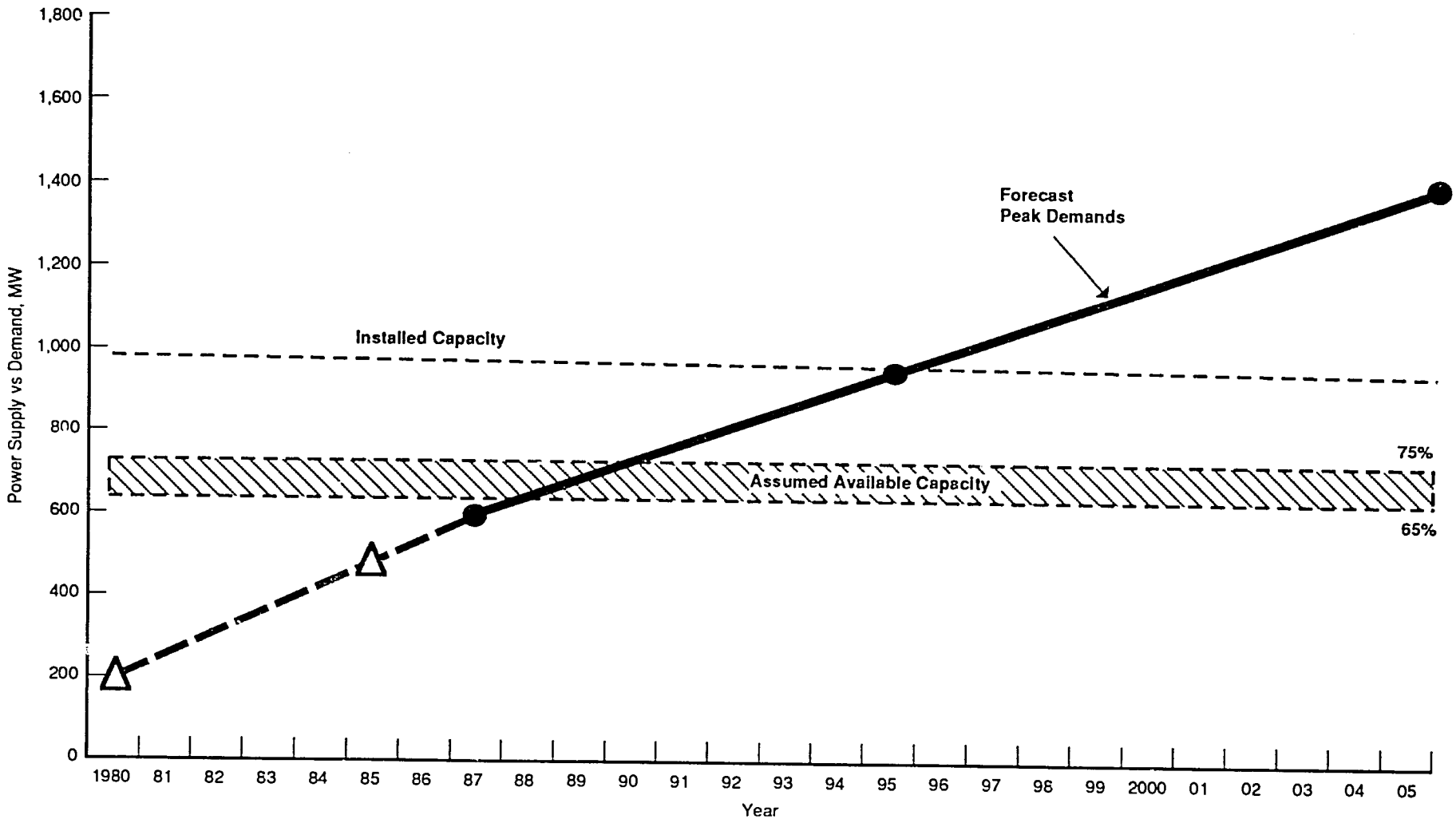

Figure 1-3 Forecast Jordan Power Supply vs Demand

- Mineable shale quality of 2250 Btu/lb or better as fuel for the boiler plant.
- Natural gas resources will not be found to be so abundant as to become a competitive indigenous fuel for power generation.
- Continued expansion of Jordan's economy with annual power demand growth rates higner than 4 percent.
- Older power generation plants are retired in an orderly manner.
- A 15 percent increase or more, compared to present values, in the price of imported crude oil or coal fuels for the time frame under consideration (25 years, commencing in 1995).
- Adequate manpower availibility in Jordan to build and operate an oil shale project.
- Suitable financing for the leveraged capital required for both the Prototype Project and the Commercial Scale Project.

Based on these results it is concluded that JEA/NRA is justified in expanding the Government of Jordan's efforts toward commercialization of its oil shale-to-power program.

1.4 RECOMMENDATIONS

A recommended Action Plan is presented in Section 10 of the study report. The proposed next phase is to create definitive designs and budget grade cost estimates, suitable for project contract purposes. To move forward with this resource development in a timely manner requires immediate interim funding to develop the program, including a:

- Plan of Work
- Budget
- Schedule

One key decision that must be reached early-on relates to the need/desire to undertake a $110-million (20 MW) or $165 million (50 MW) Prototype Project prior to embarking upon the $1000 million (400 MW) Commercial Scale Development. The engineering design risks of proceeding directly into a first

100 MW Commercial Scale Operation must be weighed against the economic penalties associated with first building a smaller prototype project. Substantial subsidies will be needed for either a 20 MW Demonstration Plant or 50 MW Prototype Project. Economies of scale certainly favor a 50 MW size unit for this next step. Further, the engineering design risks involved with future scale-up to the 100 MW Commercial Scale boiler are reduced. However it must be recognized that the investment exposure is fifty percent greater with the 50 MW Prototype Project compared to a 20 MW undertaking.

It is significant that commercial experience presently being gained on circulating fluidized bed boilers fuel with coal, culm and other fuels, and the continuing improvements that are anticipated during the next several years should be of direct benefit to Jordan's oil shale program.

Nevertheless, experience with processing oil shales in the U.S. and elsewhere indicate that it would be prudent to build a prototype boiler before embarking on construction of several parallel large size plants in order to answer scale-up design issues.

It should be emphasized, however, that the basic concept of direct combustion of a high ash fuel is not at issue. Pyropower believes it already has sufficient test burn data and operating experience to be in a position to warrant boiler performance at 50 MW. The argument for a 50 MW step is centered on the need to address design issues for optimizing a 100 MW boiler plant, in particular solids materials flow, rather than any need to prove the technology feasibility.

In light of the above points, it is suggested that two action plans be considered:

- <u>Option 1</u> - attempt to contract with owners of existing (or under construction) fluid bed combustors to test large tonnage quantities of Sultani oil shale for several months of sustained operation. This will involve developing a small mine and shale process facility in Jordan and the shipping of crushed shale to the foreign plant.

- Option 2 - proceed with development of designs for a single 50 MW fluid bed boiler as the first stage of a commercial scale power project that will consist of multiple 100 MW power generation stages. All integrated project facilities would be designed for the 100 MW scale operation. When satisfactory performance is demonstrated on the 50 MW prototype boiler, a second parallel 50 MW boiler would be added to achieve the first 100 MW stage full capacity operation. Subsequent units will be 100 MW size modules incorporating 100 MW size boilers.

Figure 1-4 shows an example schedule for the oilshale to power development plan outlined in Option 2.

The anticipated power demand growth, prospects for future power exports, and expected retirements of existing generating capacity together indicate that there should be a sense of urgency in getting started with this next step in the oil shale-to-power development program. If the Prototype Plant program outlined in Option 2 is embarked upon in 1989/90 then JEA/NRA will be prepared to go forward with commercial scale shale power plants commencing in the mid-1990s, when Jordan's need for additional generating capacity will justify such an investment.

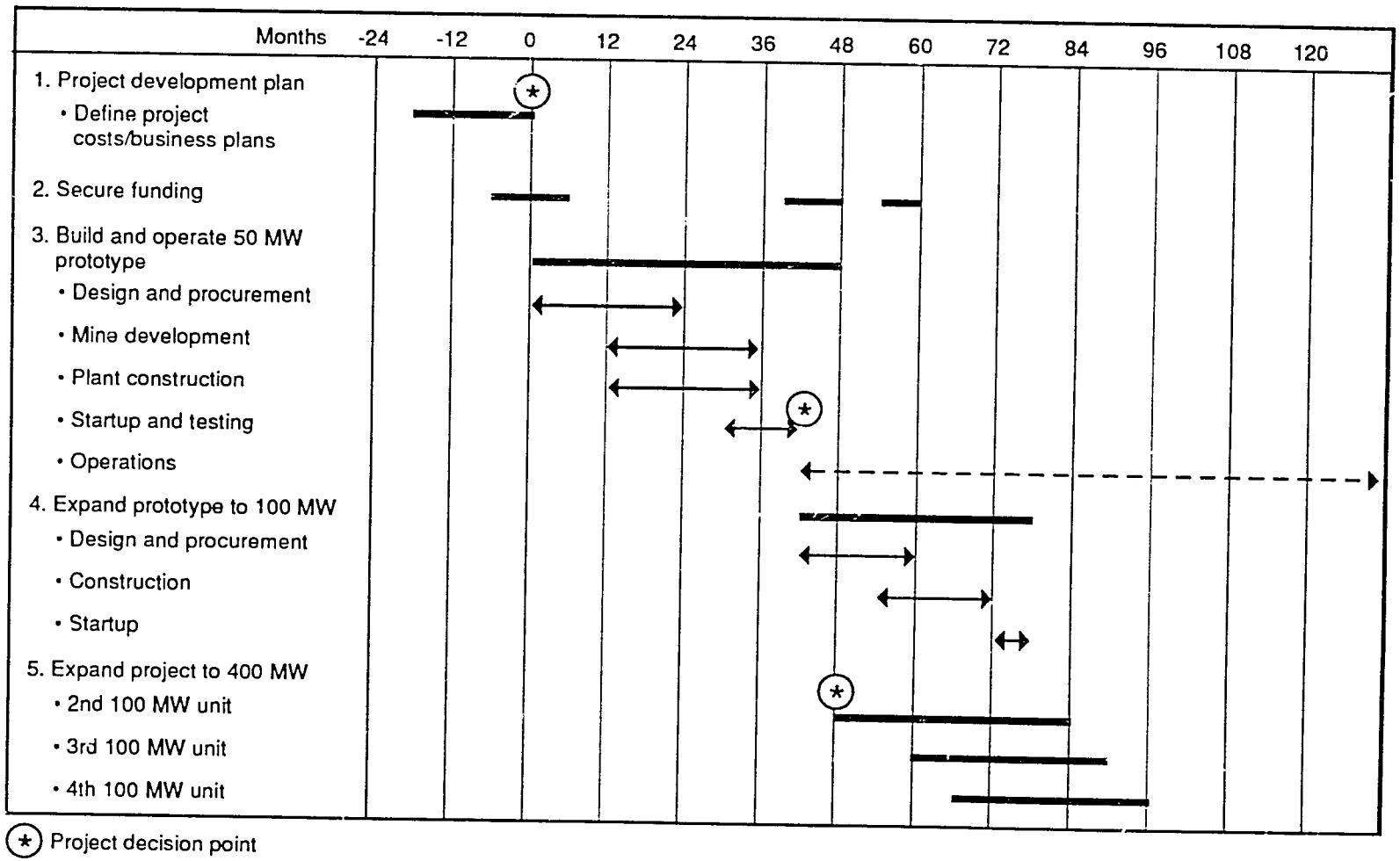

Figure 1-4 Conceptual Project Development Plan

Section 2
Introduction

Section 2

INTRODUCTION

The Hashemite Kingdom of Jordan with a population of some 3,000,000 is a dynamic country with a growing commercial and industrial economy. The explosive growth in electric power demand experienced in the late 70s and early 80s has now stabilized at an expected demand growth rate of 4 to 6 percent annually to the year 2000. Installed power generating capacity, while adequate to meet 1987/88 peak demands, is not expected to meet the 1995-2000 requirement.

Jordan currently is almost totally dependent on imported crude oil and petroleum products to operate its entire economy. These imports are a significant and growing burden to the Jordanian economy:

Table 2-1

JORDAN IMPORT ENERGY COST FORECAST*

	1987	2000
Annual Cost	$360 Million	$840-990 Million
Percent of GNP	7.8%	(11±)
Crude Oil Price	$17.53/B	$24.20/B

Faced with such a large and growing foreign exchange drain, the government of Jordan and USAID agreed in 1986 to examine the feasibility for development of Jordan's indigenous oil shale resources for power generation purposes. The primary objectives for this preliminary study are to determine both the technical and the economic feasibility of an oil shale fueled power plant in Jordan.

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*Source: Meta Systems, Hagler-Bailly, Bechtel report entitled: "Report on Long Term Energy Policy and Investment", dated March 22, 1988.

A pilot test program on a 75 ton sample of Jordan oil shale has been carried out to prove the technical viability of a circulating fluid bed combustion method for steam generation. The Ahlstrom Pyroflow Process was employed in this assessment. An evaluation of Jordan's current and future electric power demand prospects and the need for incremental generating capacity are a part of this feasibility study. Conceptual designs and cost estimates for an "Integrated Oil Shale Power Project" (see Figure 2-1) have been developed. The integrated project includes facilities for: a mine and oil shale process (crushing) plant at the Sultani Deposit to supply properly sized raw oil shale fuel to a Pyroflow boiler plant, a steam turbine electric generation plant with necessary auxiliary equipment, a spent shale ash and overburden disposal system, and the on-site and off-site infrastructure as required in the following project development alternatives:

- 50 MW Prototype Plant
- 20 MW Demonstration Plant
- 400 MW (4x100) Commcercial Scale Plant

Preliminary evaluation of the environmental considerations involved with the Jordan oil shale to power development has been carried out.

An economical analysis based on the foregoing results compares cost of power for oil shale fueled power plant developed at Sultani with a new oil or coal fired power plant at Aqaba. In considering these results it must be kept in mind that the agreed upon scope of work was limited to conceptual designs and costs and that further detail work is needed to create the type of definitive cost information needed for commercial project contractual purposes involving bankable documentation.

The Prefeasibility Study starts with certain basic concepts:

- Adequate oil shale resources exist at Sultani to support an oil shale to power commercial scale development.
- Fluidized bed combustion technology exists to utilize this Jordanian energy resource.

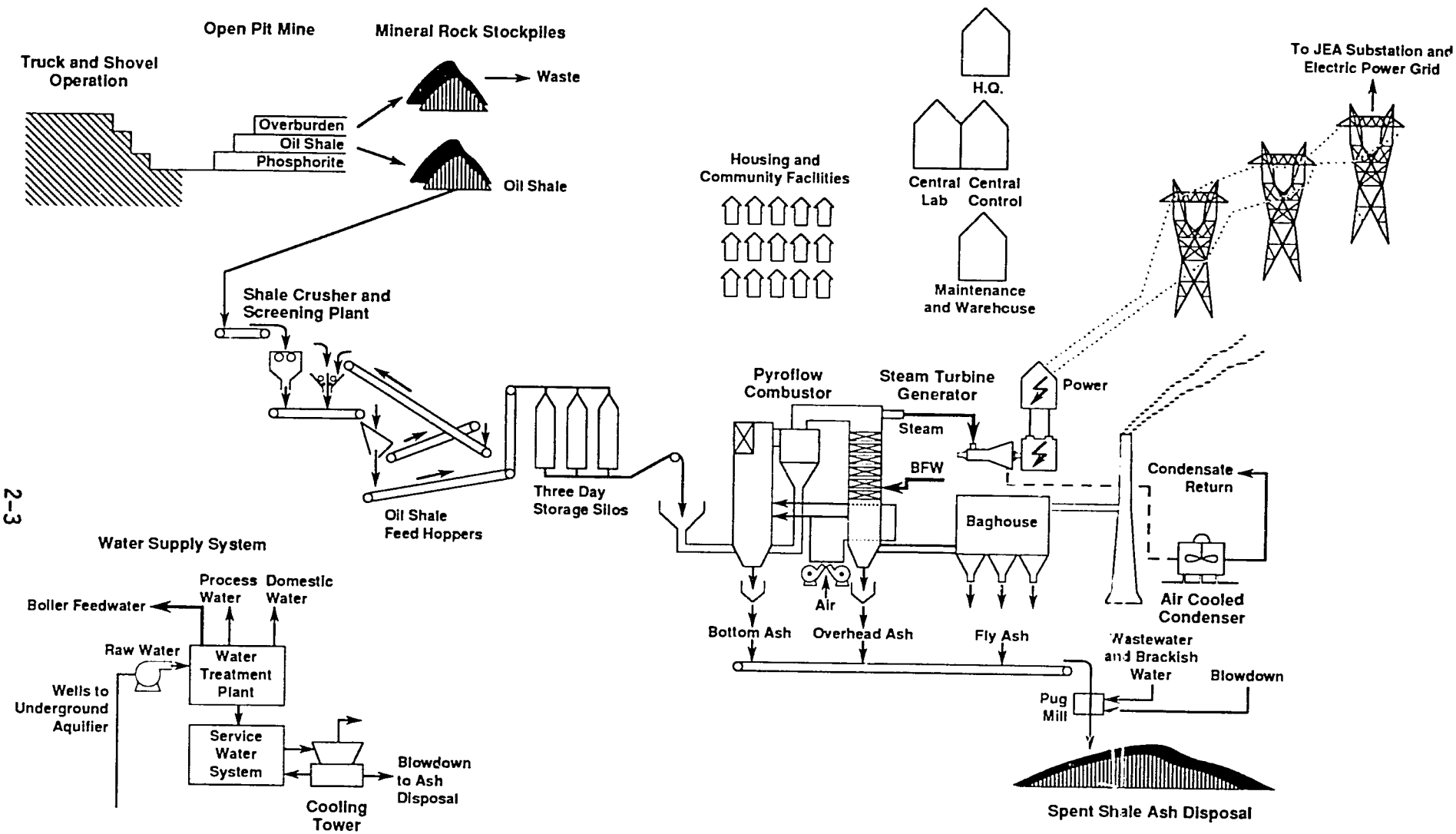

Figure 2-1 Schematic Conceptual Facilities Jordan Oil Shale to Power Project

- The Jordan economy continues to grow and the demand for additional power generation capacity will be required in the near future.
- Oil shale to power development will:
  - Result in significant savings in Jordan's foreign exchange used for imported energy fuels.
  - Create new job opportunities to help the national economy grow.
  - Improve Jordan's energy supply security.

The Prefeasibility Study does identify a number of factors that are either unknown or hard to define at this time and that will impact the decision to proceed with an oil shale to power project:

- Expected growth rate of the Jordan Economy and its associated power consumption for the period 1995 to 2020.
- Expected demand for power exports to Syria and Egypt.
- Natural Gas resource development in Jordan
- Future price trends for petroleum crude oil
- Availability and cost of capital for oil shale developments.

Except for the matter of power demand growth, this report does not attempt to deal with these uncertainties.

This report focuses on all of the technical information required to define the concepts of an Integrated Oil Shale Power Project as shown in Figure 2-1.

The following subsections present certain basic information utilized in the development of this Prefeasibility Study.

2.1 SULTANI OIL SHALE RESOURCE

Studies by others (Jordan National Resources Authority studies) indicate that the oil shale resources within the Kingdom of Jordan may exceed 10 billion tons. Extensive core drilling by the National Resources Authority (NRA) at

three deposits (shown in Table 2-2) indicate 3 to 4 billion tons are readily accessible for development. The location of the shale deposits is shown on the map, Figure 2-2.

Table 2-2

JORDAN OIL SHALE RESOURCES

	El Lajjun	Sultani	Jurf-ed Drawish
Exploitable Resources (billion tons)	1.2	0.9	2.5
Oil Shale Thickness (mean avg. - meters)	29.6	31.6	68.3
Overburden Thickness (mean avg. - meters)	25.8	69.3	47.3
Shale Oil Content (mean avg. - wt%)	10.5	9.7	5.7

The Sultani oil shale resource is located 115 kilometers south of Amman and covers an area of about 25 square kilometres. The surface topography of the area is essentially flat but the east side of the deposit is bordered by a ridge of moderately high hills. Faults crossing the area have formed the Sultani graben which has preserved the oil bearing strata. The lower portion of Muwaqqar Chalk Marl Formation, a soft marl sequence of various colors, contains the oil shale reserves. The upper portion of the formation contains the same sequence but is barren of bitumens. Underlying the Muwaqqar is the Al Hasa Phosphorite Formation which contains unexplored phosphorites. Recent core drilling near the proposed demonstration mine site reveals 3 to 12 metres of phosphorite material. Above the Muwaqqar are found gravels of Pleistocene Age and alluvium and wadi sediments of Holocene to Recent Age.

The oil shale is a bituminous marlstone consisting mostly of carbonate minerals. The hydrocarbon content of the shale rock varies from 2 to 17 wt.% and is thought to comprise ancient organic debris including spores and pollens.

Hashemite Kingdom of Jordan

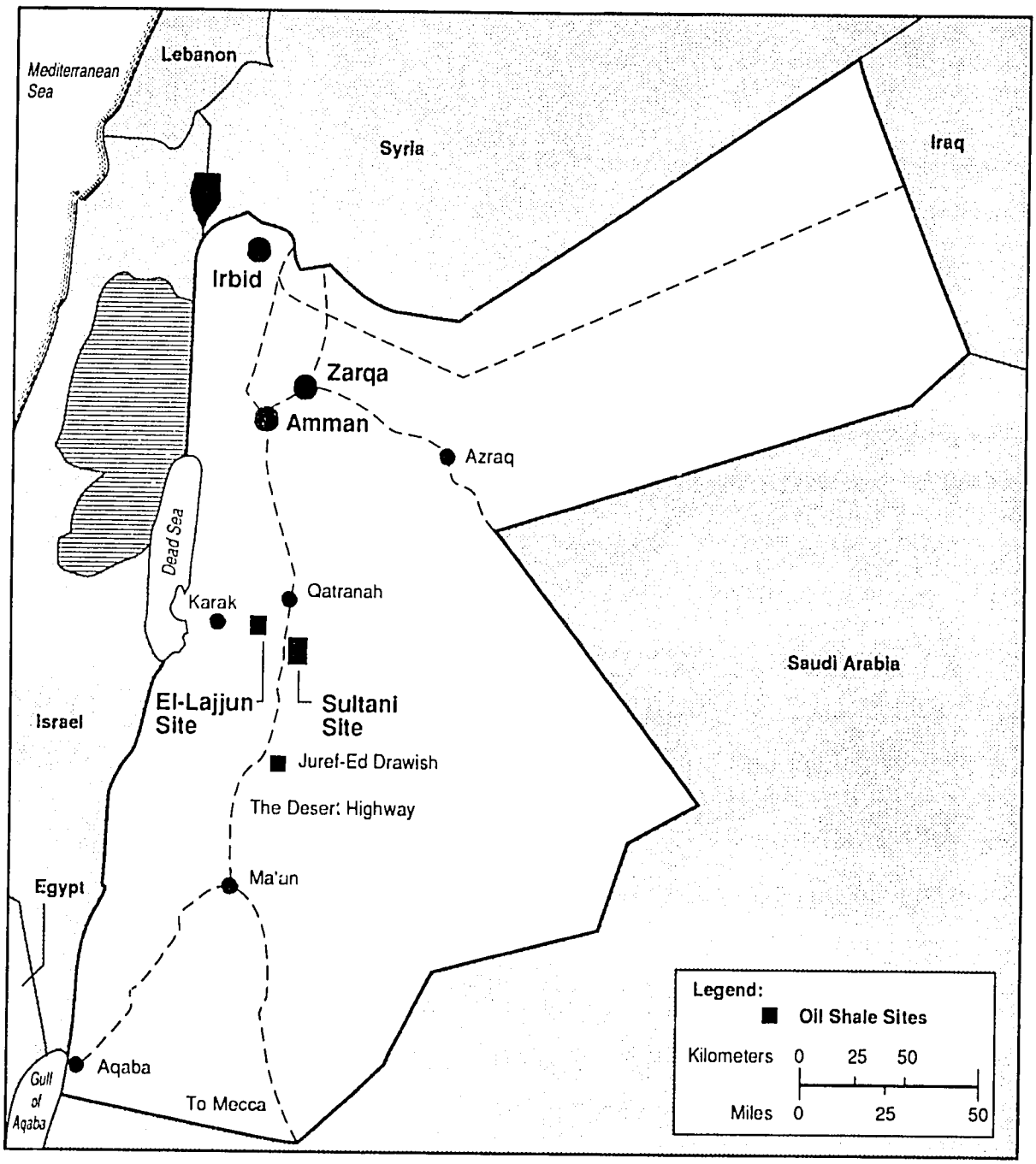

Figure 2-2 Location of Sultani and El Lajjun Oil Shale Deposits and of Major Roads, including the Desert Highway

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NRA's reports of their core drilling and core assay work relative to the Sultani Deposit are presented in the following pubications:

- Sultani Oil Shale Deposit
  July 1987
  by Engineer M. Haddadin
  Geology Directorate, Economic Geology Division
  Jordan Natural Resources Authoritt
  (Appendix 2)

- Investigation of the Oil Shale Deposits at Jurf-ed Darawish, El Hasr and Sultani
  July 1985
  Technical Cooperation Project No. 78.2165.5 by
  Henry Hufnagel
  Federal Institute for Geoscience and Natural Resources
  Hannover, Federal Republic of Germany (BRG)

- Supplemental Core Drilling - Sultani Mine Area
  August 1988
  NRA draft report attached to JEA 8/23/88 letter to Bechtel.
  (Appendix 2)

Bechtel's assessment of the reserves at Sultani are based on a total of 53 drill holes drilled by NRA and BRG of the Federal Republic of Germany. A more recent drilling program was conducted by NRA within these reserves where 25 drill holes were drilled on 150 metre spacings to define a small area in the northwest sector near the proposed mine. The oil content of 42 drill hole cores in the earlier drilling was determined by the Fischer Assay method and other analysis such as calcium carbonate, sulfur, inorganic and organic carbon were determined for 15 drill holes. In the latest drill program only the oil content of the cores was determined.

NRA assembled this information into geologic maps consisting of the following:

- Structural contour map of the upper oil shale surface.
- Structural contour map of the lower oil shale surface.
- Isopach map of the overburden thickness.
- Isopach map of the oil shale thickness.
- Iso-line map of the oil shale assay oil content (percent).

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By using the mineable reserve criteria of including those reserves with greater than 5 percent oil content by weight and less than a 3 to 1 stripping ratio based on volume of overburden to oil shale, it was determined that the Sultani reserves are located in two distinct areas, namely, North and South. The findings of this investigation are as presented in Table 2-3.

Table 2-3

SULTANI OIL SHALE MINEABLE RESERVES

AREA	Oil Shale Tonne x 10^6	Oil Content Wt. Percent	Overburden $M^3 \times 10^6$	Stripping Ratio M^3/M^3	Stripping Ratio M^3/Tonne
North	320	7.44	384	2.16:1	1.20:1
South	658	7.61	627	1.71:1	0.95:1
TOTAL	978	7.55	1011	1.86:1	1.03:1

The oil shale measure tends to thicken going from north to south, however, the overburden also is thicker in the South Mining Area.

A further classification was made of the oil shale reserves by their oil content percentage, as shown in Table 2-4.

Table 2-4

TONNES OF SULTANI OIL SHALE RESERVES BY PERCENT OIL CONTENT

AREA	5% Oil T x 10^6	6% Oil T x 10^6	7% Oil T x 10^6	8% Oil T x 10^6	9% Oil T x 10^6	10% Oil T x 10^6	Total T x 10^6
North	Nil	24.440	158.075	114.407	23.407	Nil	320.329
South	2.075	82.416	238.067	186.870	144.420	4.750	658.598
TOTAL	2.075	106.856	396.142	301.277	167.827	4.750	978.927

This resource assessment indicates that these are adequate oilshale reserves at the Sultani deposit to support a 400 MW power project for more than 25 years operation. The North Area alone is large enough to handle this requirement.

2.2 JORDAN POWER DEMAND AND SUPPLY

The results of Oak Ridge National Laboratory (ORNL) studies of electric power demands in Jordan and forecasts of future demand growth vs. installed generating capacity are presented in Appendix 6. ORNL studies are largely based on:

- Jordan Electricity Authority (JEA) annual reports for various years.
- JEA 1987 forecast for demand growth and for future retirement of existing generating capacity.
- Meta Systems/Hagler-Bailly/Bechtel, Report on Long Term Energy Policy and Investment, draft dated March 22, 1988 and prepared for Jordan Ministry of Energy and Mineral Resources.

The reference studies used in this assessment indicate that the explosive growth rates seen in Jordan's economy during 1975-80 (over 14 percent annually) have slowed significantly during 1980-85 (around 5 percent annually) and currently are in the range of 2.5 to 4.0 percent annually. The range of forecasts of future growth of GDP in the Jordan economy was 4.1 percent on the low end to 5.6 percent on the high end over the 1986-2000 time period.

Industrial power usage has stabilized at about 40 percent of total power demand in recent years. The cement, potash, phosphate and fertilizer industries do not appear to be growing significantly. On the other hand power exports to surrounding countries could grow from their current low levels. Consequently future prospects for demand growth are uncertain.

Comparison of electricity demand forecasts for the period 1986-2000 (Table 2-5) indicate continued slow growth, but at rates that are much below the 26 percent and 18 percent annual growth experienced in 1975-80 and 1980-85 respectively:

ORNL's assessment compares the currently installed generating capacity of 979 MW with to growing "peak" demand of 593 MW in 1987. At 65 percent Capacity Factor the JEA power plants would have a reasonable margin of safety to meet

the 1987 "peak" demand. While it is not clear exactly how much of the existing installed generating capacity is available at any moment in time to meet peak demands, it seems reasonable to employ a 65 percent Capacity Factor. This compares to 1987 capacity factors of 52 to 56 percent experience by JEA for their base load power plants, Aqaba I (260 MW) and Hussein (396 MW), during most of 1987. USA utility plants of comparable size and fuel experience 70 to 80 percent capacity factors. Consequently there appears to be incentive to examine ways to upgrade the availability of existing base load units to obtain more onstream capability.

Table 2-5

FORECAST POWER DEMANDS IN JORDAN

	Percent Annual Growth	
	JEA	Meta Systems, Etal
1986-1990	9.6	4.9
1990-2000	6.0	3.9
Average	6.9	4.2

JEA forecasts containing significant growth of peak demand, reaching 900 MW in 1995 and 1400 MW in year 2005. Therefore currently installed power generating capacity soon will be inadequate.

With scheduled retirement of existing generating capacity, the installed capacity drops from 979 MW to 850 MW by 1995. Using a 65 percent capacity factor for power plant availability, there is an indicated a need for incremental new plant of 350 MW (540 MW installed) by 1995 and 850 MW (1300 MW installed) by 2005.

If JEA continues with the current plan of seeing the operating results of a 20-50 MW demonstration/prototype oilshale power plant before embarking on a commercial scale shale project and the time required to design, build and operate such a demonstration unit, it is concluded:

- It is unlikely that a decision can be taken to build a commercial scale oil shale project prior to 1994/95.

- It appears that JEA should plan (pending resolution of the natural gas availability question at the Risha discovery) to go forward soon with the Aqaba II oil/coal fired unit.

It should be recognized that there is a high degree of uncertainty on several key factors that affect the foregoing conclusions:

- Expected growth rate of the Jordan Economy for the period 1995 to 2020.
- Expected demand for power exports to Syria and Egypt.
- Natural gas resource development in Jordan.
- Future price trends for petroleum crude oil and coal for the period 1995 to 2020.

2.3 PYROFLOW PROCESS BACKGROUND

The Ahlstrom Pyroflow circulating fluidized bed boiler is based on second generation fluidized bed technology, as distinct from earlier bubbling fluidized bed designs.

2.3.1 Circulating Fluid Bed Principles

Fluid bed principles are best illustrated by examining the gradual increase of gas velocity through a fixed bed of material. The particles are initially stationary and system pressure drop is a function of velocity. As the minimum fluidizing velocity is reached, the pressure drop reaches a maximum and the particles become fluidized. As gas velocity increases, the bed expands until the entrainment velocity is reached and material starts elutriating from the bed. Higher gas velocities result in greater elutriation and solids recycle is required to maintain the solids inventory. A circulating fluid bed operates in this region.

A circulating fluid bed is characterized by a high-fluidizing velocity, the absence of a defined bed level and extensive solids entrainment. Hot cyclone(s) separate most of the entrained material which is returned to the combustion chamber through nonmechanical seal(s). Internal solids recycling occurs as a result of the high differential ("slip") velocity between the gas

and solids. The large solids circulation rate provides for a uniform temperature, high heat transfer coefficients and excellent mixing.

Crushed oil shale contacts primary or fluidizing air in the lower combustion chamber. The oil shale is combusted in an oxygen starved (reducing) environment while the calcium carbonate in the oil shale is calcined to lime. Secondary air is introduced at a higher level to provide the additional air required for complete combustion.

The lime component of the shale reacts with the sulfur dioxide in an oxidizing environment to form calcium sulfate.

Combustion and sulfur retention occur at a temperature of approximately 1550-1650°F thereby providing maximum calcium utilization for SO_2 removal while minimizing the formation of "thermal" NO_x. The conversion of fuel bound nitrogen to NO_x is inhibited through the use of staged combustion. Combustion efficiency is high due to the long solids residence time and well mixed isothermal environment.

The major advantages of the Pyroflow circulating fluidized bed combustion system can be summarized as follows:

- Fuel Flexibility. Pyroflow boilers can be designed to fire a wide range of fuels including high ash and high moisture coals, oil shale, coke, and biomass.

- Low Sulfur Emissions. Downstream flue gas desulfurization is not required to meet environmental regulations. Sulfur is captured by calcium carbonate in the combustion chamber.

- High Combustion Efficiency. Excellent vertical and lateral mixing efficiency and a long solids residence time resulting from high gas solids slip velocity ensures optimum carbon burnout.

- Low NO_x Emmissions. Low combustion temperture and staged combustion result in low NO_x emissions which meet most regulatory standards without downstream treating.

- Eliminating of Fouling. Low combustion temperature eliminates slag formation and reduces the volatilization of alkali salts. This reduces boiler corrosion and convective surface fouling.

- o High Turndown. The high velocities in the combustion chamber permit large load reductions without bed slumping.

2.3.2 General Description

The major components of the Pyroflow boiler system are the combustion chamber, the hot cyclone collector(s), loop seal(s), and convective section. Combustion and sulfur retention reactions take place in the combustion chamber, which is fully water-cooled. Fuel is fed to the loop seals and if required to the lower combustion chamber. Limestone is not required for this application due to the inherent calcium carbonate in the oil shale. Fuel feed locations are designed for optimal mixing.

Combustion air is supplied by primary and secondary air fans and by a high pressure centrifugal fan. Primary air, which fluidizes the bed is supplied to the air distribution grid at the bottom of the combustion chamber. Secondary air is introduced at two levels in the lower refractory lined portion of the combustion chamber to ensure complete combustion and to reduce NO_x emissions. Secondary air is also ducted to the start-up burners,

The hot cyclone collector(s) separates entrained bed material and uncombusted fuel from the flue gas stream. The collected particles drop into the cyclone stand-pipe(s) where they are conveyed through a specially designed fluidized nonmechanical seal back to the combustion chamber.

Flue gas leaves the hot cyclone collector(s) and passes through the superheater and economizer sections of the system. Next, the flue gas passes through the airheater, enters a multicyclone dust collector where particulate matter is removed. Then the flue gas enters a baghouse filter where more particulate matter is removed. Clean flue gas is discharged to stack via the induced-draft fan.

Treated feedwater is supplied to the economizer, where it is heated before entering the steam drum. From the drum, the water is delivered via downcomers to the combustion chamber where it receives additional heat from the fluidized combustion reaction. The resulting steam/water mixture is returned to the

steam drum. Steam is separate in the steam drum and routed through a series of super-heaters and then to the main steam header. Desuperheaters are located between superheaters.

2.3.3 Development of Ahlstrom Pyroflow

Since 1969 fluidized bed combustion research has been one of the major projects at the Hans Ahlstrom Laboratory, Ahlstrom's Research and Development division located in Karhula, Finland. Conventional bubbling fluidized bed combustion systems were developed mainly for the incineration of industrial and municipal waste sludge, and a total of ten commercial bubbling bed systems were sold during the 1970s.

Experience with these early systems revealed the problems inherent in scale up for power plant applications.

Investigation of circulating fluidized bed combustion was initiated in the mid-70s. A pilot plant was constructed in 1976 to demonstrate this approach. The results achieved during the pilot plant development and the research and development program resulted in the Pyroflow circulating fluidizing bed combustion (CFBC) design and the subsequent commercial applications.

As a result of rising energy costs, Ahlstrom started a program aimed at reducing its costly dependence on fuel oil for its own facilities. The Pihlava plant, a board and sawmill facility near Pori on the west coast of Finland, was one of Ahlstrom's most oil-dependent mills. This board and sawmill plant was the site of Ahlstrom's first commercial circulating fluidized bed boiler which burned local peat or wood waste from plant opertions.

This first commercial CFBC unit began operation in January 1979 and has since then consistently demonstrated multi-fuel capability and the fact that fuel quality is not critical to overall plant performance. For example, the Pihlava plant is designed for wet fuel with a high volatile content. Nevertheless, about 4000 tons of coal had been fired in this plant by the end of 1981.

In 1978 Ahlstrom evaluated replacing the existing oil-fired boilers at its pulp and paper mills at Kauttua in western Finland with a Pyroflow unit capable of burning wood wastes, peat, and coal. This evaluation showed clear advantages, both in terms of economical and efficient plant operation. The order was placed in September 1979 and plant startup and commissioning began in May, 1981. The Kauttua plant Pyroflow unit has operated with availability levels in excess of 95 percent.

The experience gained through engineering, constructing and operating Pyroflow boiler systems in Pihlava and Kauttua makes Ahlstrom unique compared with other boiler suppliers. Since that time, Pyropower has succeeded in using Ahlstrom's Pyroflow operations experience to develop Pyroflow technology for U.S. applications, including combustion of high-sulfur coals, anthracite culm, and other low-grade or waste fuels previously considered unusable as fuels - either because of low heating content or emission levels associated with high sulfur content.

2.3.4 Operating Experience

There are more than 60 Ahlstrom Pyroflow units in operation or under construction worldwide with over 100 years of unit operating experience.

A description of selected key projects is presented in Appendix 3.

Table 2-6 presents up-to-date information on the operating histories of certain Pyroflow commercial units. The experience with coal fired units has been uniformily good. Experience with the higher ash/lower BTU culm feed unit is not yet extensive enough for meaningful comment.

Table 2-6

AHLSTROM PYROFLOW POWER AVAILABILITY

UNIT	PARAMETERS	APPL.	AVAILABILITY (%) 1981	1983	1984	1985	1986	1987
Kauttua	200,000 lb/hr 1235 psig, 930°F	Cogen.	91	100	96.6	96	95.2	94.6
Hylte Bruk	143,000 lb/hr 960 psig, 840°F	Cogen.	99.4	98.3	98.9	98.5	92.0	data unavail.
Hyvinkaa	22 MMBtu 160 psig, 250°F	Dist. htg.	98.1	96.5	99.6	96.5	data unavail.	data unavail.
Kemira Oy Oulu	155,000 lb/hr 1305 psig, 960°F	Cogen.	–	99.5	99.8	98.6	99.9	96.6
Alko Oy	55,000 lb/hr 610 psig, 840°F	Process	–	100	100	100	100	data unavail.
Cal Portland Cement	190,000 lb/hr 650 psig, 825°F	Cogen.	–	–	–	–	98	data unavail
B.F. Goodrich	125,000 lb/hr 500 psig, 470 °F	Process Steam	–	–	–	–	97	data unavail.

DEFINITIONS:

Availability - $\frac{\text{trouble free operation time}}{\text{total time period of measurement}}$

Operating Factor - $\frac{\text{actual energy development during the period}}{\text{corresponding energy at nominal capacity over same period}}$

2.4 STUDY PLAN

The program of work developed by USAID in 1987 involved 12 Tasks and participation by 4 Organizations: Bechtel, Jordan Electricity Authority (including NRA), Oak Ridge National Laboratory and Pyropower Corporation. Assignments were as follows:

Task 1	Program Management	Bechtel
Task 2	Sample Procurement	JEA/NRA
Task 3	Test Burn and Report	Pyropower
Task 4	Jordan Power Demand Assessment	ORNL
Task 5	Small Boiler (20 MW) Design/Cost	Pyropower
Task 6	Small Project BOP Design/Cost	Bechtel
Task 7	Full Scale Boiler (100 MW)Design/Cost	Pyropower
Task 8	Full Scale Project BOP Design/Cost	Bechtel
Task 9	Environmental Assessment	ORNL
Task 10	Economic Financial Review and CFB Technology Assessment	ORNL/Bechtel
Task 11	Action Plan	Bechtel
Task 12	Final Report	Bechtel

The 1987 scope of work was modified at the April 1988 review meeting in Amman to cover preparation of cost estimates for 3 project size operations:

- 20 MW Demonstration Plant
- 50 MW Prototype Project (New)
- 400 MW (4x100) Commercial Scale Project

No additional funding was provided for the third extra case study (50 MW).

The prefeasibility work scope was for development of conceptual designs and order of magnitude cost estimates. No vendor equipment quotations were to be obtained. Further, it was requested that the economic analysis consider both on imported fuel oil fired boiler (like Aqaba I) and an imported coal fired boiler as alternatives to the 400 MW oil shale case study. JEA provided data for Aqaba I and Bechtel was to provide curve-type estimates for the coal plant include coal terminal facilities.

The Government of Jordan (NRA) obtained a 75 ton sample of oil shale from the upper layers of the shale beds via an open pit mine they developed in the NW corner of the Sultani deposit. The mined shale was blended, analyzed, packaged and shipped to Finland by NRA in October 1987.

The pilot plant fluid bed combustion tests were made at the Ahlstrom laboratory facilities at Karhula, Finland in January 1988. These tests were witnessed by Bechtel and by JEA/NRA. The test results were presented informally at the progress report meeting in Amman, Jordan in April and a Interim Report was issued by Pyropower Corporation (an Ahlstrom affiliate) in June 1988. This report concludes that

> "The test results indicate that the Sultani Oil Shale, in spite of its high ash and high sulfur content, can be combusted on a stable basis in an Ahlstrom Pyropower CFB boiler with acceptably low flue gas pollutant emissions."

On July 29, 1988, Pyropower Corporation issued another Interim Report presenting its designs and cost estimates for the boiler plant to be incorporated with balance-of-plant (BOP) facilities to be designed and costed by Bechtel. This then became the starting point for Bechtel's Mining Group and Bechtel's Power Group to undertake their assignments in creating conceptual designs and cost estimates for the integrated project shown schematically on Figure 2.1. The results of Bechtel's economic analysis are presented in Section 8 of this study report.

For the three study options (20, 50, and 400 MW), Bechtel and Pyropower developed designs for 20 and 50 MW power plants and proposed "factored" estimates for the 4x100 MW power plant. Costs for the following BOP items were prepared:

- o Open Pit Mine
  - Overburden Removal
  - Oil Shale Mining and Transport
- o Oil Shale Processing
  - Crushing to minus 1/4 inch size
  - Blending and Storage

- o Boiler Plant Installation
  - Flue Gas Stack
  - Ash Handling System

- o Power Generation Facilities
  - Steam Turbine Drivers
  - Electric Power Generators
  - Auxiliaries and Switch Gear
  - Boiler Feed Water System

- o Raw Water Supply and Treating System

- o Ash Disposal System

- o On-Site Infrastructure (allowances)
  - Roads, Sewers, Power Distrib., Lighting
  - Office/Control Center/Laboratory
  - Maintenance Shop/Warehouse
  - Employee Services Center
  - Communications and Security System

- o Off-Site Infrastructure (allowances)
  - Housing
  - Community Facilities

The Design Basis Criteria employed in developing the integrated project plans are listed in Appendix 1.

Section 3
Pilot Plant Test

Section 3

PILOT PLANT TEST

One key element of the Prefeasibility Study was to establish the technical viability of burning oil shale to generate steam. This was accomplished in a two-week burn test in an 850 KW Ahlstrom Pyroflow pilot plant using a 75 ton sample of raw oil shale furnished by NRA from their exploratory pit at the Sultani deposit.

3.1 75-TON SHALE SAMPLE

As previously described the oil shale measure at Sultani varies from 20 to 40 meters thick and is covered by 40 to 100 meter of overburden. This makes obtaining a representative sample of the average raw oil shale difficult and expensive. (In a similar situation at the Moroccan Tarfaya shale deposit, Bechtel opened a pit to expose the full shale measure at a cost of $1.5 to $2.0 million U.S.)

NRA opened a pit at the northwest corner of the Sultani deposit exposing only the top oil shale layers. Eight oil shale samples were taken and analyzed. These sub-samples then were mixed into two piles designated:

- o H_1 = black colored high grade oil shale
- o H_2 = brown/grey colored low grade bituminized shale

The average oil content, as determined by Fisher Assay, for the H_1 pile ranged from 7.2 to 11.2 wt% and average 9.26 percent for six grab samples. Oil content of the H_2 pile averaged 1.2 percent. A blend then was made:

- o 90 percent = H_1
- o 10 percent = H_2

Assay oil content of the blend ranged 8.4 to 8.6 wt%.

The blended sample was loaded into 2 cu ft plastic bags and the 75 ton sample was shipped from Aqaba to Finland on October 6, 1987.

Pictures of the open pit exploratory mine are shown on Figure 3-1. Results of analytical work on various shale samples and on 18 representative Sultani core holes are presented in Appendix 3, NRA report entitled Sultani Oil Shale Blended Sample (November 1987).

The 75 ton sample appears to be significantly richer than the expected average mine run shale discussed Section 2.01 and Appendices 2&3 (Volume II). Its sulfur content would be expected (by correlation) to be somewhat higher - see Figures 3-2 and 3-3. Following is a comparison of selected properties of the 75 ton sample used in the pilot test work with our evaluation of the properties of average mine run oilshale:

	Expected Average Mine Run Shale	75 Ton Sample
Fischer Assay Oil Content, Wt%	7.5	8.4/8.6
Organic Carbon Content, Wt%	10.2	(13 ±)*
Gross Calorific Value, BTU/Lb	2,000	(2,250)*
Sulfur Content, Wt%	2.38	(2.55)*

*By correlation with Fischer Assay results in Figures 3-2 and 3-3.

It was decided to designate the 75 ton sample as Performance Fuel and the average mine run shale as Low Calorific Value Fuel. The Pyroflow boiler in this study is designed around Performance Fuel but is capable of burning low calorific value fuel.

Due to work scope limitations no determination was made of the lowest calorific value at which stable ignition can occur. It is speculated that this ignition threshold will occur in the range of 1,500 to 1,700 BTU/lb fuel. Shales of lower quality may need supplemental fuel, such as petroleum

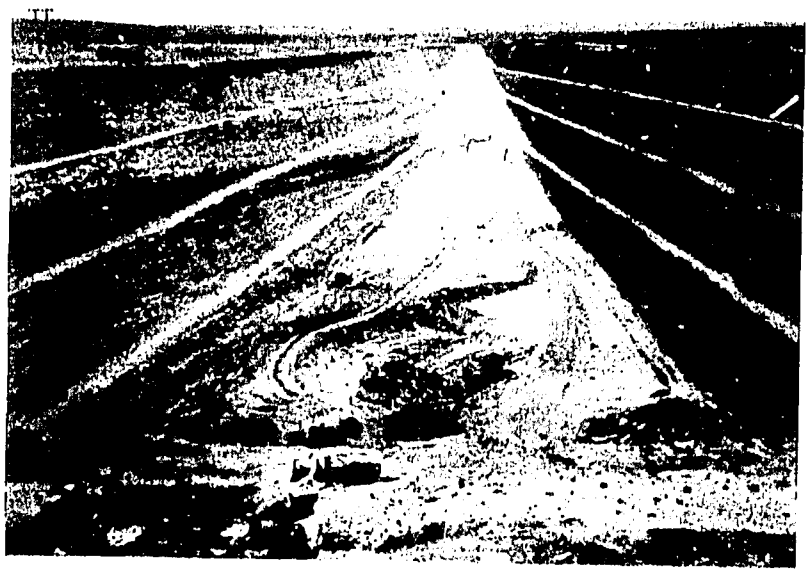
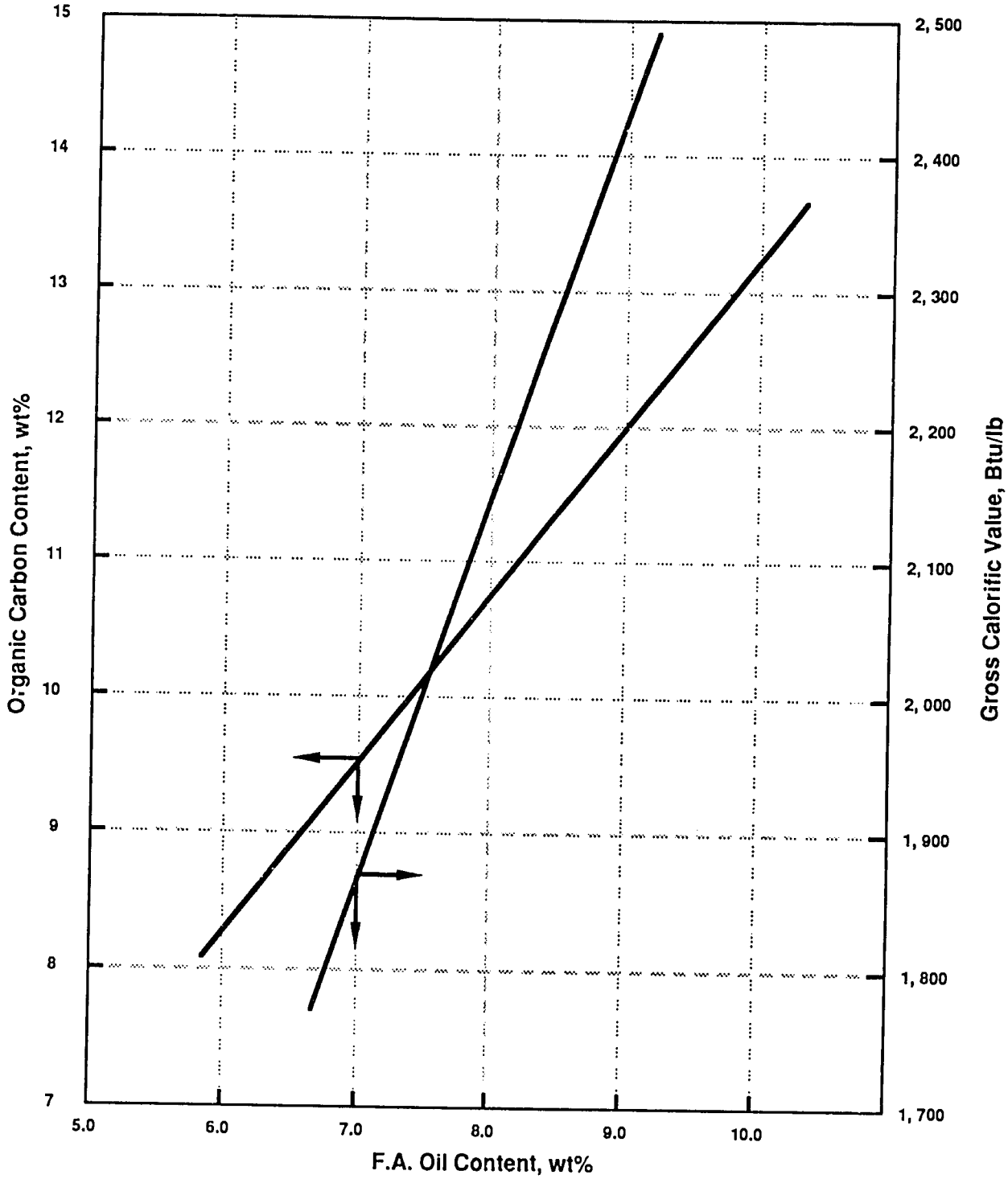


Figure 3-1 Jordan Sultani Oil Shale Exploratory Pit



Basis: 1985 German study

Figure 3-2 Jordan Sultani Oil Shale

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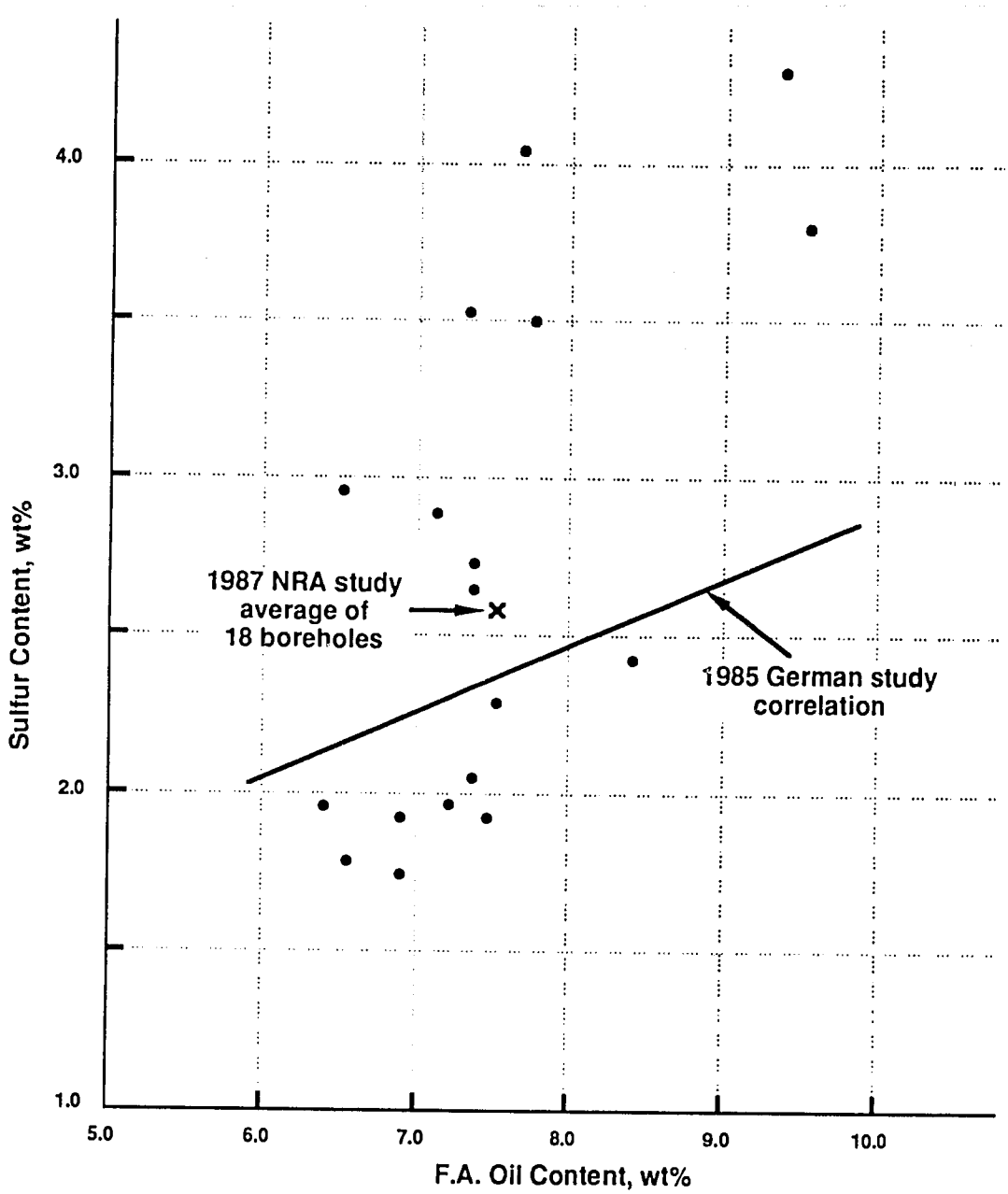


Figure 3-3 Jordan Sultani Oil Shale

coke or coal. This matter is deferred for later investigation as part of the follow-on definitive design work program.

3.2 AHLSTROM TEST FACILITY

The tests were performed in the 850 kW Pyroflow pilot plant located at the Hans Ahlstrom Laboratory in Karhula, Finland. The flow sheet of the pilot plant is given in Figure 3-4.

The inner diameter of the furnace is approximately 600 mm and overall height is 8 meters. Oil shale is fed to the furnace by means of a screw feeder. Solids are separated from flue gas in a hot cyclone and recycled into the furnace bed through the hot cyclone loopseal. Coarse bottom ash particles are withdrawn from the furnace bottom.

Bayonet cooling tubes are used in the furnace. The length that these tubes extend into the furnace is adjusted to meet the heat transfer duty required for a given tested fuel at the desired process conditions.

The flue gases from the hot cyclone are cooled in a water tube boiler, which contains two convection sections separated by a wall. After the boiler, flue gas flows through the pre-cyclone and through the baghouse where fly ash is removed. The flue gas exits to the stack via a wet scrubber.

Solids sampling points include: raw oil shale feed, bottom ash and the pre-cyclone plus baghouse fly ash streams. The oil shale feed rate is calculated on the basis of weighed fuel amounts out into the furnace and time records. Bottom ash is collected in barrels that are weighed manually. Fly ash is collected in weighing hoppers hanging from strain gages whose signals are recorded. Sampling frequency is every two hours and samples are composited for a given test period.

Process data measurement recording is done with an ALCONT automatic process control system. Continuous gas analyzing equipment includes the following:

- O_2 (in dry gas) Taylor Servomex OA570
- CO (in dry gas) Thermo Electron, Model 48

Schematic Process Flow Diagram

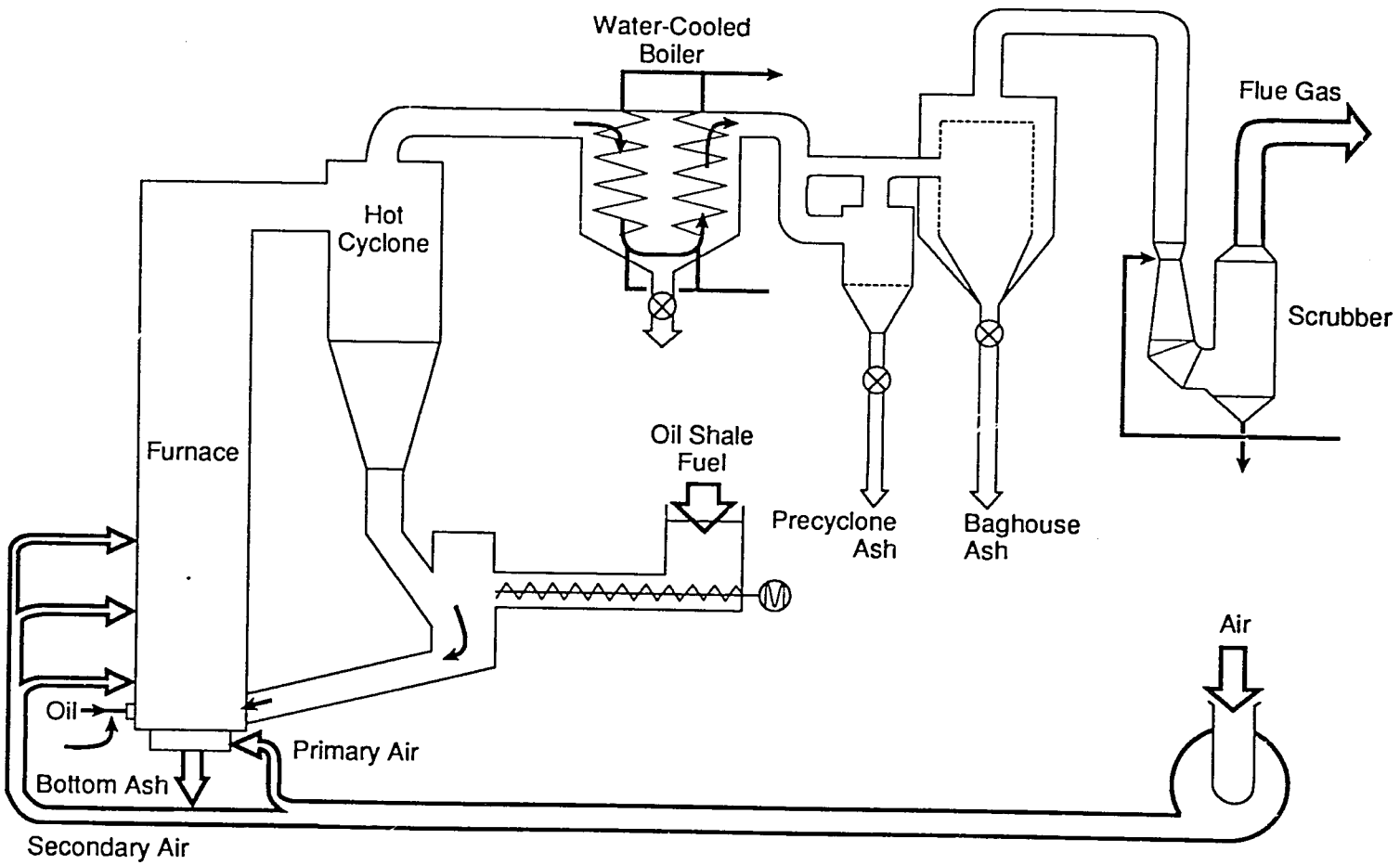


Figure 3-4 Ahlstrom Pyroflow Pilot Plant – Karhula, Finland

- o So_2 (in wet gas) Monitor Labs, Model 8850
- o NO_x (in wet gas) Monitor Labs, Model 8840

3.3 TEST RESULTS

Appendix 7 presents the Pyropower Corporation test burn report.

Based on the results of this eight-test-two-week period combustion of Jordan Sultani oil Shale, Pyropower concluded the following:

- o The sample of oil shale furnished by NRA is an acceptable fuel in an Ahlstrom Pyroflow circulating fluidized bed boiler where it burns cleanly and efficiently.
- o Combustion efficiency in excess of 98.5 percent was demonstrated.
- o Both SO_2 and NO_x emissions and CO emissions all were acceptably low. The tests demonstrated that over 90 percent of the fuel sulfur was absorbed by the inherent calcium in the oil shale. As a result no limestone additions will be needed.

Typical emissions measured during these tests were:

- o SO_2 - below 20 ppm
- o NO_x - 60 to 120 ppm
- o CO - Below 50 ppm

These values will generally meet the more stringent environmental requirements.

The shale did not appear to decreptitate appreciably within the test combustor. Ash distribution was approximately as follows:

- o Bottom Ash - 30/40 percent
- o Overhead Ash - 60/70 percent

Care should be taken in design of the raw shale crushing plant and screening system to minimize the fines content of the raw shale feedstock. This will help avoid overloading of the downstream baghouse and other ash removal facilities.

While no material balance nor energy balance data are presented in the test report, Pyropower obtained suitable data to prepare conceptual designs for the 20 MW and 50 MW boilers.

3.4 ORNL ASH STUDIES

A 10 ton sample of ash from the pilot test on Sultani oil shale was shipped to the Oak Ridge National Laboratory in Tennessee for analysis and testing. The results of ORNL studies of this material are presented in Appendix (6).

The matter of fugitive dust control is dealt with extensively in the ORNL report. Fly ash from the Pyroflow boiler will comprise about 60 percent the ash output of the plant. Since about 25 percent of the fly ash consists of particles less than 10 microns diameter, a potential health risk exists due to the possibility for inhaling such small particles. Recognizing there is potential hazard, the Bechtel waste disposal plan is based on wetting the ash with about 20 wt% water content comprising boiler blow-down and other plant waste water streams. The ash then is layered with overburden in the disposal plan to minimize wind erosion and to reduce the potential for leaching.

Preliminary testing of the leachability of spent oil shale ash identifies arsenic, cadmium and selenium as potential contaminants. However study of dilution by aquifer migration needs to be examined in greater detail to determine whether ground water contamination is a potential problem.

ORNL concludes:

- It is unlikely that shale ash will have any real value as a cement by-product.
- The P_2O_5 content of the ash is too low for further processing for phosphate recovery.
- Ash disposal by open dumping or return to the mine pit is not likely to lead to ground water contamination. However this matter warrants continuing study.

3.5 CONCLUSIONS

The test program on oil shale combustion at the Ahlstrom laboratory utilizing the shale sample furnished by NRA was successful.

The test work on the ash found no serious problems with leachability.

It is concluded that use of Ahlstrom Pyroflow technology is quite feasible from a technical standpoint.

Section 4
Integrated 50 MW Plant Conceptual Designs & Cost

Section 4

INTEGRATED 50 MW PLANT CONCEPTUAL DESIGNS AND COSTS

4.1 INTRODUCTION

At the April 1988 meeting in Amman, it was decided that a 50 MW size project should be considered in addition to the previously planned 20 MW Demonstration Scale Project and the 4X100 MW Commercial Scale Project. The reasoning was that economies of scale make it unlikely that a 20 MW plant can be operated without substantial subsidy (see Figure 1-1). It was felt that a 50 MW integrated project is the smallest size that could stand on its own feet as a prototype plant.

At the conclusion of this Prefeasibility Study - if it is decided to proceed into the next phase of oil shale development - a decision must be made on whether to focus attention on a higher total investment cost (but lower cost per Kw) 50 MW project or a lower investment cost (but higher cost per Kw) 20 MW project. The power product from either project probably will need a subsidy from the Government of Jordan.

The following subsections describe the facilities involved with an Integrated 50 MW Project.

4.2 MINE AND MATERIALS HANDLING

Details of the mine plan and shale processing plan are presented in the Mining Report (Appendix 5). Figure 4-1 shows the layout of the mine and shale processing facilities relative to the power block facilities.

The Sultani Oil Shale deposit is adjacent to the Desert Highway. Existing 400 KV and 132 KV power lines (part of the National Grid) parallel the highway to the west. The national railroad line lies east of the highway and runs directly through the north pit area of the Sultani deposit. The rail line

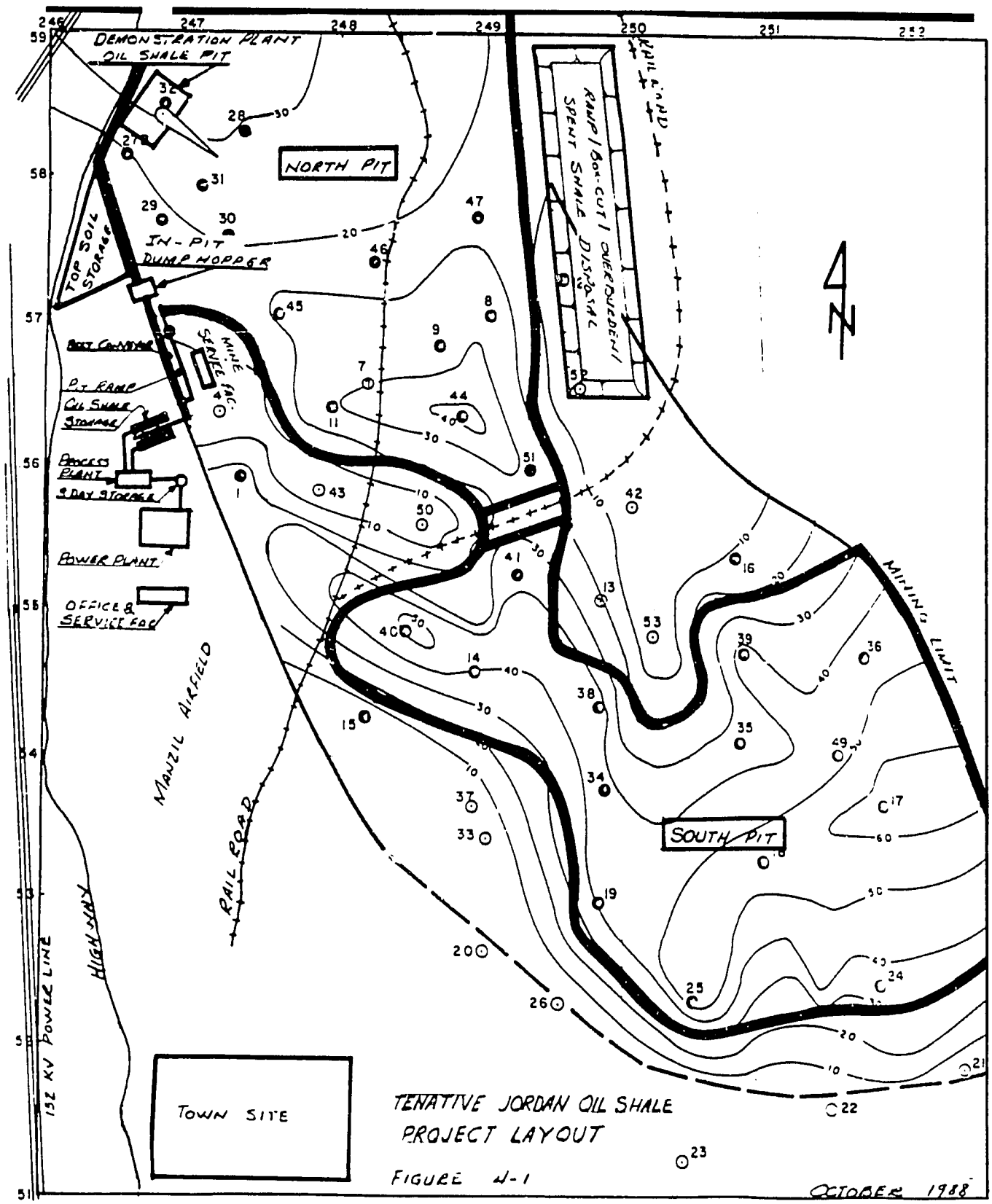


Figure 4-1 Project Layout

must be relocated to go forward with the 4x100 MW oilshale-to-power project. It is planned to expand the existing test mine pit at the northwest corner of the deposit and develop southeastward. Shale processing facilities, power block facilities, office and service facilities all would be located west of the mine pit between the mine and the highway. Location of housing and community facilities remains to be determined. It is visualized they could be west of the highway or south of the Manzil airfield.

Water wells would be drilled in the vicinity of the power plant.

4.2.1 Mine Development Plan

For the 50 MW power plant it is recommended that the existing trial pit be developed to minimize the capital expenditure for the mine. The mine will be developed for a loader and truck operation during the construction phase of the power plant in order for it to meet the oil shale demands of the power plant when it is placed into commercial operation.

The mine development will consist of widening the existing ramp, opening the pit with a box-cut, removing and storing top-soil, building haulroads and sedimentation ponds, excavating water ditches and preparing an area for the disposal of overburden and spent shale. The work required to protect the environment will be accomplished before the pit excavation begins. Water ditches will be dug on the surface around the pit area and the water disposal area to prevent pristine water from being contaminated with the disturbed areas. Sedimentation ponds will be constructed to collect water from disturbed areas. After these ponds built, the top soil in the pit area, haul roads and waste disposal area will be removed and stored for reclamation of the land. Following this work the haul road construction and pit excavation can begin.

The haulroads will be constructed of local materials such as the materials excavated from the pit and local gravels. These roads will be wide enough to accommodate two-way traffic for the 77 tonne trucks. Three haulroads, each of approximately 3 kilometres in length, will be required for the following:

- Disposal of overburden from the pit to the out-of-pit waste pile.
- Haulage of oil shale from the pit to the process plant.
- Disposal of spent shale ash from the power plant to the out-of-pit waste pile.

While the roads are being built, the existing ramp excavated at the trial pit will be widened for the 77 tonne trucks and modified to an 8 percent grade, if necessary.

At the base of the ramp a box-cut will be driven normal to the ramp toward the south and into the area recently drilled. The box-cut will expose an area on top of the oil shale that is 60 metres wide and 175 metres long which represents approximately 250,000 tonnes of oil shale in this area.

In order to gain access to the box-cut for the development of the mining benches, incline roads from the main ramp will be cut into the overburden. The west side of the box-cut will be the advancing face consisting of four benches which will not exceed 10 metres in height. The bench width will be 40 metres wide to permit sufficient turning radius for the trucks. A road and ramp system will be developed on the south end and east side of the box-cut to keep the overburden traffic separate from the oilshale mining.

During the pre-operational period approximately <u>one million bank cubic metres</u> of overburden will be excavated and hauled to the waste pile.

4.2.2 Mine Operation

For the purpose of this report the mine operation will be by the owner using owner's equipment and several key expatriate employees in the management of the operation. Mining costs received from the mine contractor are incomplete. Consequently for this Prefeasibility Study, a contract mining option could not be considered. The details as provided in the Mining Report (Appendix 5) are required for the development of the processed raw oil shale fuel cost as it enters the boiler to arrive at the proper electric power buss-bar cost.

The mine design is based on mining oil shale that meets the performance fuel calorific value specification of 2250 Btu per pound. The energy input to the boiler is 734.6×10^6 Btu per hour which is equivalent to 148.07 tonne per hour of the performance fuel. When the power plant operates at 100 percent capacity factor, the annual burn rate is 1.297 million tonnes. At a 75 percent capacity rate the annual burn rate amounts to 973 thousand tonnes.

The mine is designed to meet the fuel requirements for the plant operating at 100 percent capacity factor.

With a schedule of 900 shifts per year and operating on an overall efficiency of 72 percent, the mine will have the capability of delivering 250 tonnes per hour to the processing plant. Overburden removal will be at the average power plant operating capacity factor of 75 percent or approximately 1.265 million bank cubic metres annually.

The mine operation consists of the following activities:

- Top-soil removal and storage
- Drilling and blasting of overburden benches
- Loading and hauling of overburden for disposal to out-of pit waste pile
- Leveling waste pile
- Ripping oil shale
- Selective mining of oil shale with scrapers
- Storing oil shale in two piles by grade
- Reclaiming in approximate fuel spec mix
- Crushing and hauling to power plant stockpiles.

Top soil is removed by an auger scraper and is hauled and stored at designated areas. A blast hole driller will drill each of the four overburden benches on a 5 metre by 5 metre pattern with 170 mm diameter holes. ANFO will be the major blasting agent used. Overburden will be loaded into trucks with a

77 tonne capacity of a front end loader with a 10 cubic meter bucket. The trucks will haul the overburden to an out-of-pit waste dump where it is intermingled with spent shale ash from the power plant. A bulldozer will maintain the waste pile level. When sufficient space becomes available, the overburden and spent shale ash will be placed as back-fill in the mine pit.

Selective mining of the oil shale will be accomplished by auger scrapers with the assistance of a bulldozer ripper, when required. The oil shale will be mined in benches measuring 10 metres or less in height and 40 metres wide. The scrapers will deliver the oil shale to several stock piles, that are separated according to percentage of oil content, within the mine area. A front end loader will reclaim the oil shale from the stock piles in a manner that will produce a product that approximates the performance fuel specification. The loader dumps the oil shale into a portable crusher which crushes the oil shale to minus 100 mm and loads directly into trucks for delivery to the process plant stockpiles on the surface.

4.2.3 Oil Shale Processing

Oil shale from the mine is placed into one of two stockpiles - one will be built, sampled and tested and the second will be reclaimed by front end loader. In reclaiming the tested stockpile, a front end loader is used and with its capability of loading shale from many points on the stockpile, the mix of the oil shale can be adjusted as the impactor feed bin is being filled.

The processing plant consists of a reversible impactor in closed circuit with two vibrating screens (see Figure 4-2). This crushing facility is designed to produce 250 tonnes per hour operating at an overall efficiency of 72 percent to meet the fuel requirements of the power plant when it operates at 100 percent capacity factor. The shale processing plant operation is scheduled for 900 shifts per year. Routine daily maintenance is schedule and included in the 72 percent efficiency.

The oil shale will be crushed to a minus 8 mm product. The screen undersize will pass through a three stage sampling tower where samples are extracted according to ASTM standards. From the sampling tower the oil shale will be

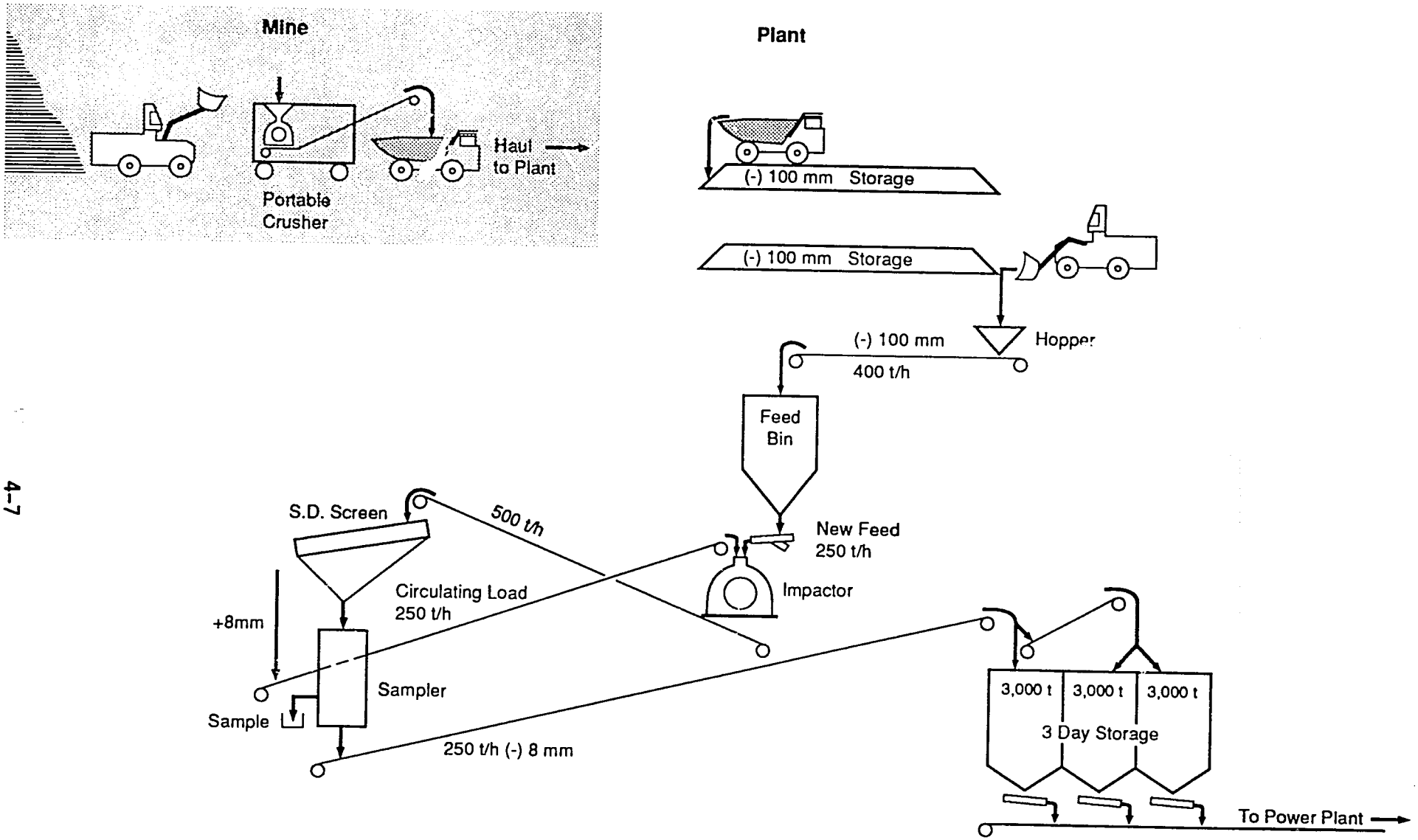


Figure 4-2 Flow Sheet – Oil Shale Processing Plant 50 MW Prototype Plant

conveyed to one of three steel silos. Capacity of each live storage silo will be 3,000 tonne. Withdrawal from these silos will be through - variable speed feeders which will dischage onto the conveyor belts feeding the power plant day bins. For the final mixing of the oil shale, the quality is controlled by withdrawing from two silos at rates consistent with the fuel specification.

4.2.4 Mine Services Facility

The mine services facility will include the maintenance and warehousing facilities for the mine and shale process plant equipment. In addition the facility will contain a change house, first aid room, training room and mine offices. These facilities are separate from the power plant because of the different type of equipment employed in these operations.

Only minor support facilities will be provided at the maintenance building since overhaul and repair of equipment components will be let to local contractors. The space allocated for maintenance is based on component replacement. Six vehicle repair bays sized to accommodate the 77 tonne trucks will consitute the maintenance facilities for this operation. These bays will be used for major work, preventative maintenance, and welding. A 25-ton overhead crane will service the bays.

4.2.5 Mining and Shale Processing Economics

Details of the oil shale mining and shale processing plant economics are included in the Mining Report (Appendix 5). The report includes the capital cost for the mine development, the mining equipment and the construction of the oil shale process plant. The report includes details of the operating cost for the mining and processing plant and the labor costs for these operations. A third feature of the report is the cash flow analysis of all known costs for the fuel entering the boiler.

The cash flow analysis was determined for debt-equity ratios of 50:50 and 80:20, respectively. Capital costs include mine development, mining equipment, process plant facilities, spare parts, working capital and interest during construction. The operating costs and other costs include parts,

supplies, fuel, purchased power, wages and fringe benefits, explosives, insurance, interst expense depreciation and amortization, management fee, return on equity and royalty. Land cost, import duties and all taxes are excluded from this analysis. A summary of this cash flow analysis which has a two year pre-operational period and a 25 year operation schedule is presented in Table 4-1.

Table 4-1

SUMMARY OF 50 MW PLANT OIL SHALE
MINING AND PROCESSING COSTS

	50/50 Debt-Equity US $1000	80/20 Debt-Equity US $1000
Capital Cost		
Mine Development	7,833	7,833
Mine Equipment	12,202	12,202
Process Plant Facilities	8,388	8,388
Spare Parts	1,300	1,300
Working Capital	2,200	2,200
Capitalized Interest During Construction	3,192	5,108
TOTAL	35,115	37,031
Operating Costs and Other Costs		
Annual Cost (weighted average)	13,118	11,556
Product Mined and Processed		
Annual Tonnes x 1000	973	973
Unit Cost		
US $/Tonne (weighted average)	13.48	11.88
US $/$10^6$Btu (weighted average)	2.72	2.39

4.2.6 Spent Shale Ash Disposal

Haulage of the spent shale to the out-of-pit waste pile or in-pit disposal area will utilize the same trucks used in the mining operation. The spent shale will be mixed with 20 percent water in a pug mill at the power plant and conveyed to a dumping point within the power plant area. Then the spent shale is loaded into the 77 tonne truck by a front end loader. At 100 percent capacity factor the power plant will produce approximately 100 tonnes per hour of spent shale and when pugged the spent shale will have a weight of 125 tonnes. Spent shale will be hauled away by one truck on two shifts per day. Spare truck or front end loader are not required since this operation can depend upon the mine fleet availability.

4.2.7 Spent Shale Ash Disposal Economics

The same details performed for the mining and processing of the oil shale economics were done for the spent shale disposal. These details are found in the Mining Report (Appendix 5). The summary of these findings are present Table 4-2.

Table 4-2

SUMMARY OF 50 MW PLANT SPENT SHALE ASH DISPOSAL COSTS

	50/50 Debt-Equity US $1000	80/20 Debt-Equity US $1000
Capital Cost		
Equipment	1,945	1,945
Spare Parts	120	120
Working Capital	140	140
Capitalized Interest During Construction	110	176
TOTAL	2,315	2,381
Operating Costs and Other Costs		
Annual Cost (weighted average)	823	710
Spent Shale Ash Hauled		
Annual Tonnes x 1000	815	815
Unit Cost		
US $/Tonne (weighted average)	1.01	0.87

4.2.8 Operating Requirements

The manpower and utility requirements of the 50 MW mine and shale processing facilities are as follows:

- Total men - 163 (including 2 expatriates)
- Purchased power - 7,400,000 Kwh/year
- Water (ex ash wetting)- 2,533,000 liters/day
  - 761,000 cubic meters/yr.

4.2.9 Contract Mining Option

The foregoing conceptual mine and shale processing design contains the normal contingencies and spare capacity that are built into a grassroots project serving a substantial downstream investment in power block facilities. If it is decided to build this 50 MW Integrated Project as a 1 to 2 year demonstration project, then a separate study should be made to determine the investment savings that might be made in the mining facilities plan by eliminating standby equipment.

One option might be to operate the Demonstration Project with a contract mining program employing idle equipment said to be available in Jordan. Insufficient data were available about the present condition of such equipment and any costs required for equipment rehabilitation. Because of study budget limitations, consideration of savings that might accrue with contract mining has been deferred until a follow on development program phase.

The use of contract mining is unlikely to significantly change the economic prospects for the 50 MW project.

4.3 BOILER PLANT - 50 MW PLANT

Appendix 8 presents the Pyropower Corp. report on its design for the Pyroflow Process fluid bed boiler facilities.

Because the boiler design is considered to contain proprietary information, only an expurgated version of the design is contained in the Appendix. Under

a confidentiality agreement, Bechtel received sufficient boiler plant design details to prepare a conceptual plan and an order of magnitude cost estimate for these boiler facilities for inclusion in the integrated overall project cost estimate and economic evaluation.

The reader is referred to the following Sections 4.4 and 4.6 for further details on integration of the boiler into the power block design and operation.

4.4 POWER PLANT DESCRIPTION

The following sections describe the conceptual design of a 50 MW nominal capacity oil shale-fired power plant and auxiliaries located within the power plant boundaries. The design bases and assumptions used for the conceptual deisgn are listed in Appendix 9. A list of major equipment with design ratings for the power plant also is included in Appendix 9. The power block design is specifically aimed at minimizing water consumption through maximum use of air cooling.

4.4.1 Thermal Cycle

The plant design uses a conventional Rankine Steam Cycle. The steam cycle uses a non-reheat condensing steam turbine rated at 59.3 MW (gross) with throttle conditions of 103 kg/sq cm Abs (1463.5 psia) and 510°C (950°F). The design condenser pressure is 139.7 mm HgA (5.5 inches HgA) at 24°C (75°F) ambient temperature. The turbine throttle flow is 226,700 kg/hr (500,000 lb/hr) at the design point. The turbine has four uncontrolled extractions for feedwater heating; this heats the feedwater to a temperature of 188°C (370°F) before entering the economizer. A heat balance cycle diagram is included as Figure 4-3 at the end of this section.

4.4.2 Selection of Turbine Throttle Conditions

Steam turbine throttle conditions of 103 kg/sq cm Abs (1463.5 psia) and 510°C (950°F) have been selected for this plant. Based on the experience on previous projects, it is assumed that these throttle conditions are likely to be the optimum for the cycle considered and the expected fuel costs. Although use of a higher throttle steam temperature of 538°C (1000°F) would improve

cycle efficiency, the resulting operating cost savings are likely to be offset by the increased capital costs for the higher grade materials required for the turbine and the boiler. Specific studies have not been made to select an optimum cycle for this plant.

4.4.3 Steam Cycle Description

Combustion of oil shale in the boiler generates heat which converts boiler feedwater to superheated steam. This superheated steam is transported to the steam turbine through the main steam piping. Steam is then expanded through the steam turbine which is coupled to a generator, thereby producing power. Steam is extracted from the turbine at four points for feedwater heating. The steam turbine exhausts the balance of the steam to an air cooled condenser where it is condensed to liquid as heat is removed from the steam by ambient air. The condensate from the condenser is collected in a condensate storage tank and is pumped by two 100 percent capacity condensate pumps to a deaerator through two low-pressure feedwater heaters. The low-pressure feedwater heaters are shell and tube type heat exchangers which heat the condensate using steam extracted from the steam turbine. The deaerator is a contact type heat exchanger and uses extraction steam to heat the condensate and to remove noncondensible gases. The water leaving the deaerator is then pumped by two 100 percent capacity feedwater pumps to the boiler through a high-pressure feedwater heater. Like the low-pressure feedwater heaters, the high-pressure heater uses steam extracted from the steam turbine to heat the feedwater. Feedwater heating improves cycle efficiency.

4.4.4 Boiler

The boiler is described in Section 4.3 in detail. A circulating fluidized bed, oil shale-fired, balanced draft, drum type boiler is used. The steam conditions at the superheater outlet are:

Flow	=	226,700 Kg/hr (500,000 Lbs/Hr)
Pressure	=	109.9 Kg/sq cm Abs (1563.5 psia)
Temperature	=	512.8°C (955°F)

The analysis of oil shale fuel is shown in Table 2 of Appendix 9. At design conditions, the boiler heat input is 734.6 million Btu/hr and consumes about 148 tonnes (163 tons) per hour of oil shale having a higher heating value of 1,250 Kcal/kg (2,250 Btu/lb). No. 2 fuel oil is required for starting the boiler and each startup requires about 11,000 gallons of No. 2 fuel oil (diesel).

4.4.5 Overall Plant Performance

The expected overall plant performance at design conditions is summarized in Table 4-3

Table 4-3

PLANT PERFORMANCE AT DESIGN CONDITIONS

1.	Boiler heat input, 10^6 Btu/hr	734.6
2.	Boiler efficiency %	76.15
3.	Boiler steam output, lbs/hr	500,000
4.	Turbine throttle conditions, psia	1,463.5
	°F	950
5.	Design condenser pressure, inches HgA (Expect 3.5 inches HgA annual average pressure at ambient conditions)	5.5
6.	Plant gross output at 5.5 in. HgA condenser pressure, MW	59.3
7.	Auxiliaries power consumption, MW	9.2
8.	Plant net output, MW	50.1
9.	Plant net heat rate, Btu/Kwh (Efficiency = 23.3%)	14,663
10.	Design fuel consumption, lbs/hr	326,500
11.	Plant water consumption, gpm	207
12.	Total ash production, lbs/hr	218,100

The air-cooled condenser pressure varies with the ambient dry bulb temperature. For the same boiler heat input, the turbine gross output varies

with the condenser/pressure. For example, the gross MW output is expected to be 58.5 MW at 6.5 inches HgA condenser pressure and 55.7 MW at 9 inches HgA condenser pressure. The steam turbine should be operated with condenser pressure less than 9 inches HgA. The unit output should be reduced if the condenser pressure rises above 9 inches HgA during high ambient temperature conditions.

Assuming an annual average ambient dry bulb temperature of 16°C (61°F) and 75 percent plant capacity factor, expected annual performance of the unit is summarized in Table 4-4

Table 4-4

EXPECTED ANNUAL PERFORMANCE OF THE UNIT

1.	Plant net output at annual average condenser pressure of 3.5" HgA, MW	51.5
2.	Annual net kilowatt hours	338.36 x 10^6
3.	Annual fuel consumption, tonnes	972,400
4.	Annual ash production, tonnes	657,000
5.	Annual fuel oil consumption, gallons	165,000
6.	Annual water consumption, gallons	1,400,000
	, cubic meters	5,300

4.4.6 Power Plant Fuel Handling System

All necessary fuel preparation work such as blending, crushing and sizing of oil shale to meet the Pyropower boiler fuel specifications will be done in the mining facilities described in Section 4.2. Prepared fuel, meeting the boiler fuel specifications is delivered and stored in three live storage silos, each with 3000 tonnes capacity. This storage capacity is adequate to supply fuel to the plant for about 60 hours of full load operation. See Figure 4-4 at the end of this section. Two 100 percent capacity belt conveyors, each rated at 250 tonnes/hr are provided to transport oil shale from the live storage silos

to the two inplant storage silos (feed bins), each with 550 tonnes capacity. This inplant storage capacity is adequate for about 8 hours of boiler plant operation. A vibratory feeder is installed below each live storage silo outlet. Two way chutes with power operated flop gates are provided at the discharge of each feeder so that fuel from the silo can be diverted to either of the belt conveyors. The combination of two belt conveyors and chutes with flop gates provides adequate redundancy in the power plant fuel handling system. Fuel from the belt conveyors is delivered into a small distribution bin with a bifurcating chute and a flop gate so that fuel from either of the conveyors can be delivered to anyone of the two inplant storage silos.

4.4.7 Power Plant Ash Handling System

Cooled boiler bottom ash is collected in bottom ash surge hoppers. The hoppers have a combined storage capacity of approximately one hour of bed ash generated at one hundred percent capacity of the boiler. Bottom ash from the surge hoppers and fly ash from the boiler air preheater hoppers and baghouse hoppers is pneumatically conveyed to the bottom ash and fly ash storage silos respectively by vacuum systems. See Figure 5-5 at the end of this section. The ash storage silos have about 24 hours storage capacity based on performance fuel. Ash from the air in the vacuum system is separated in two stages by using a cyclone type separator and a second stage baghouse filter mounted on the top of the ash silos. Ash collected in the cyclone and baghouse is discharged to the respective ash storage silos. Ash free air from the conveying system is discharged to the atmophere. For each conveying system, two 100 percent capacity exhaust vacuum blowers are used. Wear resistant type piping system is used for conveying ash to the storage silos. The ash removal system is sized for handling maximum ash generated while firing fuel with highest ash content.

Ash from each silo is discharged to pug mills where it is mixed with about 20 percent water by weight to minimize generation of dust during transportation to mine and disposal. Wetted ash from the pug mills is discharged to the ground through a stacking conveyor. Trucks are used to haul wetted ash from this discharged area back into the mine for disposal. Each silo also has a discharge spout for dry unloading if required. Unloading blowers are used to fluidize ash and facilitate its flow from the silos.

4.4.8 Plant Water Systems

The plant water system consists of the following:

- Raw water system
- Treated plant makeup system
- Plant service water system

Recognizing that the plant is located in a desert area and that availability of water is limited to less than 2 million cubic meters per year, a dry cooling tower is used for removing heat from the steam turbine exhaust. A small wet cooling tower is used to reject heat to the atmosphere from plant auxiliaries such as ash coolers etc.

The raw water system consists of two 100 percent capacity deep well pumps, each rated at 400 gpm at an assumed head of 300 ft. See Figure 4-6 at the end of this section. These pumps deliver water to a well water storage tank of 100,000 gallon capacity. Two 100 percent capacity raw water pumps supply water for the following uses:

- Makeup water to the service water system cooling tower
- Boiler treated makeup water
- Treated drinking water
- Pump seals
- Miscellaneous uses

The well water storage tank also serves as the reservoir which supplies water to the fire protection water pumps in case of emergency.

The boiler makeup water treatment plant consists of two 100 percent capacity demineralizer trains, each rated at 30 gpm flow. Each demineralizer train consists of a feed pump, a carbon filter, a cation unit, an anion unit, and a mixed bed unit. Demineralized water is stored in a demineralized water storage tank of 20,000 gallon capacity. Two 100 percent capacity demineralized water pumps supply makeup water to the condenser. The demineralizers are periodically backwashed and regenerated with sulfuric acid

and sodium hydroxide. These chemicals are stored in 2000 gallon capacity tanks at the site. A neutralization tank with sump pumps is provided to neutralize demineralized waste effluents from the plant.

The plant service water system consists of a small cooling tower, two 100 percent capacity service water pumps, basket strainers, piping and valves. See Figure 4-7 at the end of this section. The service water system supplies cooling water to the following:

- Generator air coolers
- Turbine lube oil coolers
- Boiler feed pump lube oil and seal water coolers
- Vacuum pump intercondenser
- Gland steam condenser
- Induced draft fan lube oil cooler
- Primary air fan lube oil cooler
- Secondary air fan lube oil cooler
- Ash screw coolers
- Sample coolers

Service water also is used for wetting ash and to minimize dust during ash handling. All system water losses are made up by the raw water system.

The main liquid wastes from the plant are fuel and ash handling area runoff, makeup demineralizer regeneration wastes and cooling tower blowdown. Fuel and ash handling area wastes can be collected and routed to a pond for settling and neutralization. Makeup demineralizer regeneration wastes are routed to a neutralization sump for pH control. Cooling tower blowdown requires no treatment since circulating water pH is maintained between 8 and 9 during normal system operation. Waste water can be used for wetting ash for disposal and therefore very little plant waste water discharge to the local streams is expected.

4.4.9 Electric Power System

The electrical power system generates and delivers electrical power to the high voltage transmission system via a main step-up transformer. It also distributes all required electrical power to the plant auxiliaries. The system is shown on Figure 4-10 at the end of this section.

Power Generation and Transmission. Power is generated by a generator, rated 22KV, three phase 50 Hertz. Power is delivered to the high voltage transmission system through a main step-up transformer, rated 22-400 KV.

The generator is protected by a generator breaker, rated 3000 A, 750 MVA which is operated normally closed. When the unit is started up, this generator breaker is opened and power to the plant auxiliaries is supplied from the high-voltage transmission system through the main step-up transformer. The system is provided with sensitive protective relaying system, instrumentation and control.

Power Distribution System. The power distribution system provides reliable power to all plant auxiliaries through an auxiliary transformer, rated 22-6.6 KV. Power is distributed at several voltage levels as follows:

- The 6.6 KV Medium Voltage System supplies power to large (above 250 HP) motors and the load center (LC) transformers.
- The 380 V Low Voltage System supplies power to small motors (below 250 HP) and miscellaneous electric loads. Motors rated 75-200 HP are connected to load centers and motors rated less than 75 HP are connected to motor control centers (MCC). The MCC also distributes power to lighting and power panels.
- The DC Distribution System supplies power to small DC motors and DC control circuits.
- The Vital AC System provides uninterruptible power for vital control, monitoring and shutdown circuits.
- The Instrument AC System supplies power to instrumentation, control and communication circuits.
- Miscellaneous support system include the grounding lighting, cahodic protection, raceway and wiring systems.

- A small capacity Service Transformer provides power to selected vital auxiliary loads, when the generator and high voltage offsite power supply are out of service.

4.4.10 Plant Control System

A central control room is be utilized for major plant control functions and for plant monitoring. Local instrument and control panels for the boiler are provided to enable local startup of the boiler and auxiliaries. Electronic instruments are powered by an uninterruptible power supply at 115 V ac, single phase. Positioners, actuators, etc. are powered by dry, clean, oil free instrument air.

4.4.11 Plant General Arrangement Drawings

The power plant location is shown on Figure 4-1. The highway and the transmission lines are to the west of the power plant. The mine is to the east. The mining operation is responsible to mine oil shale, crush, size and deliver to the storage silos at the power plant.

Equipment layout within the power plant area is shown on Figure 4-8 (at the end of this section). This drawing shows the relative locations of turbine, generator, air cooled condenser, boiler, baghouse, stack, inplant fuel storage silos, auxiliary bay etc. Figure 4-9 (at the end of this section) shows views of boiler and turbine houses.

4.4.12 Power Plant On-site Infrastructure

The power plant includes an adminstrative and warehouse building. A small machine shop, electrical shop and instrument shop are required. A laboratory to analyze oil shale fuel and water also is required. An on-site employee services facility including: first-aid facility, personnel changeout facility, bath and lavatory facilities also are needed.

The capital cost of the on-site infrastructures also includes roads, fencing, gates, yard lighting and telecommunication, yard drainage and sewerage, and security systems etc. Fuel, chemical, waste and by-product storage and handling systems are not included in on-site infrastructure cost.

The on-site infrastructures cost is included in total power plant capital cost as described in Section 4.6.1.

4.5 OFF-SITE INFRASTRUCTURE

For this study an allowance was made for inclusion of off-site infrastructures. The off-site infrastructures include housing and community facilities for the integrated project employees and families. The estimated project staffing includes:

o	Mining and shale processing	163
o	Power Block	151
o	Project Management	10
	Total Staff	324

The cost of these community facilities is provided for as an allowance in developing the integrated project capital cost as described in Section 4.6.1.

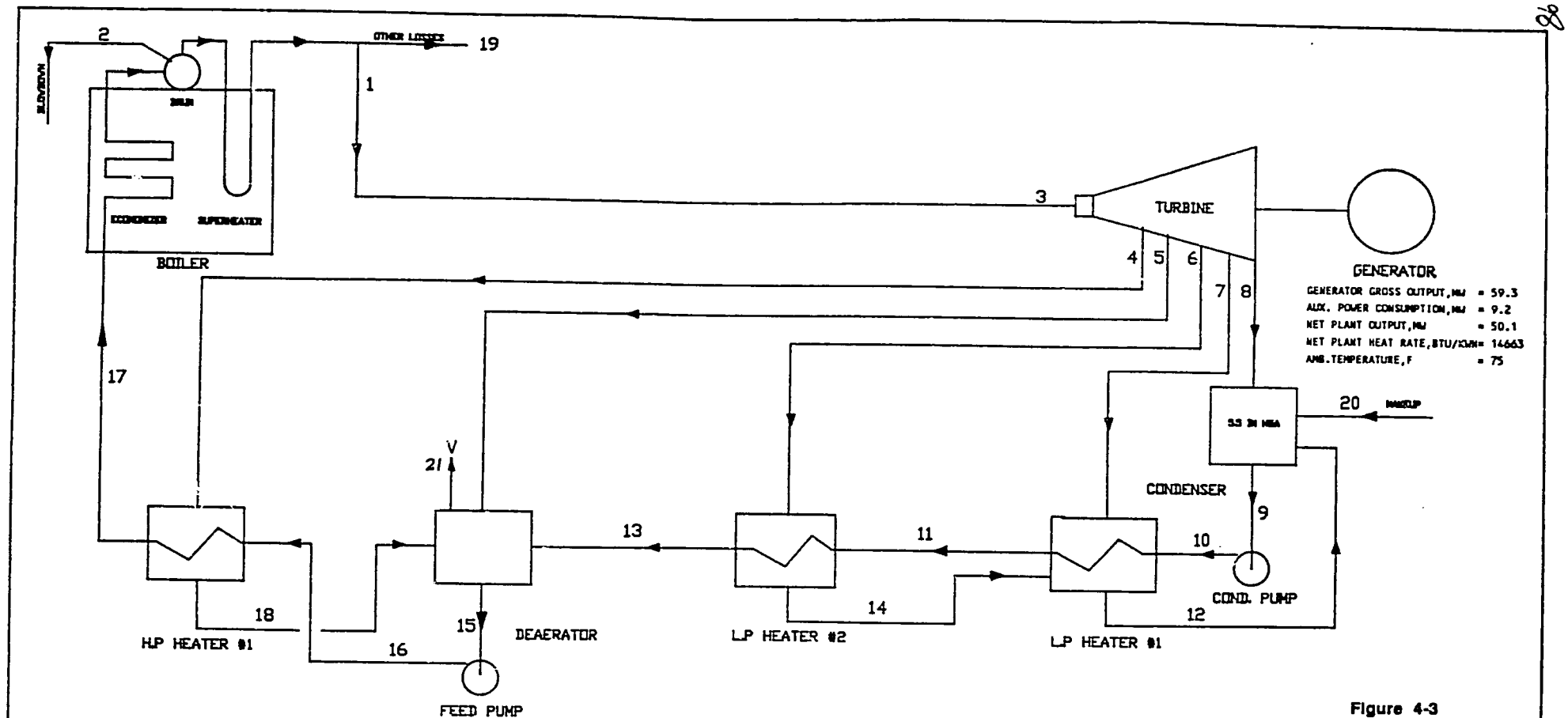


Figure 4-3

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PRESSURE,PSIA	1563.5	1728.5	1463.5	182.5	74	27	5.7	2.7	2.7	124.3	110.3	5.4	95.3	25.7	70.3
TEMPERATURE,F	955	615.4	950	488.4	333.2	244.4	167.8	137.4	132.7	132.7	160.6	142.5	236.5	170.6	303.2
ENTHALPY,BTU/LB.	1460.8	639.9	1461.3	1264.5	1196.2	1130.8	1043.3	1005.7	100.7	100.7	128.8	110.4	205.1	138.7	273
FLOW,LB/HR	500000	5000	500000	33797.4	32391.4	33523.8	12253.2	387734.2	440311.2	440311.2	440311.2	46077	440311.2	33823.8	506000

STREAM NO.	16	17	18	19	20	21
PRESSURE,PSIA	1788.5	1773.5	173.4	1563.5	30	[illegible]
TEMPERATURE,F	306.9	370	316.9	955	60	303.2
ENTHALPY,BTU/LB.	280	345.2	287.3	1460.8	[illegible]	1180.6
FLOW,LB/HR.	506000	506000	33797.4	1000	[illegible]	500

BOILER HEAT INPUT,MMBTU/HR.	= 734.6
BOILER LOSSES,MMBTU/HR	= 175.1
CONDENSER DUTY,MMBTU/HR.	= 350.9
GROSS POWER,MMBTU/HR.	= 202.5
OTHER STEAM CYCLE LOSSES,MMBTU/HR.	= 6.6

BECHTEL

JORDAN OIL SHALE TO POWER PROJECT

STEAM CYCLE DIAGRAM
50 MW UNIT

M001

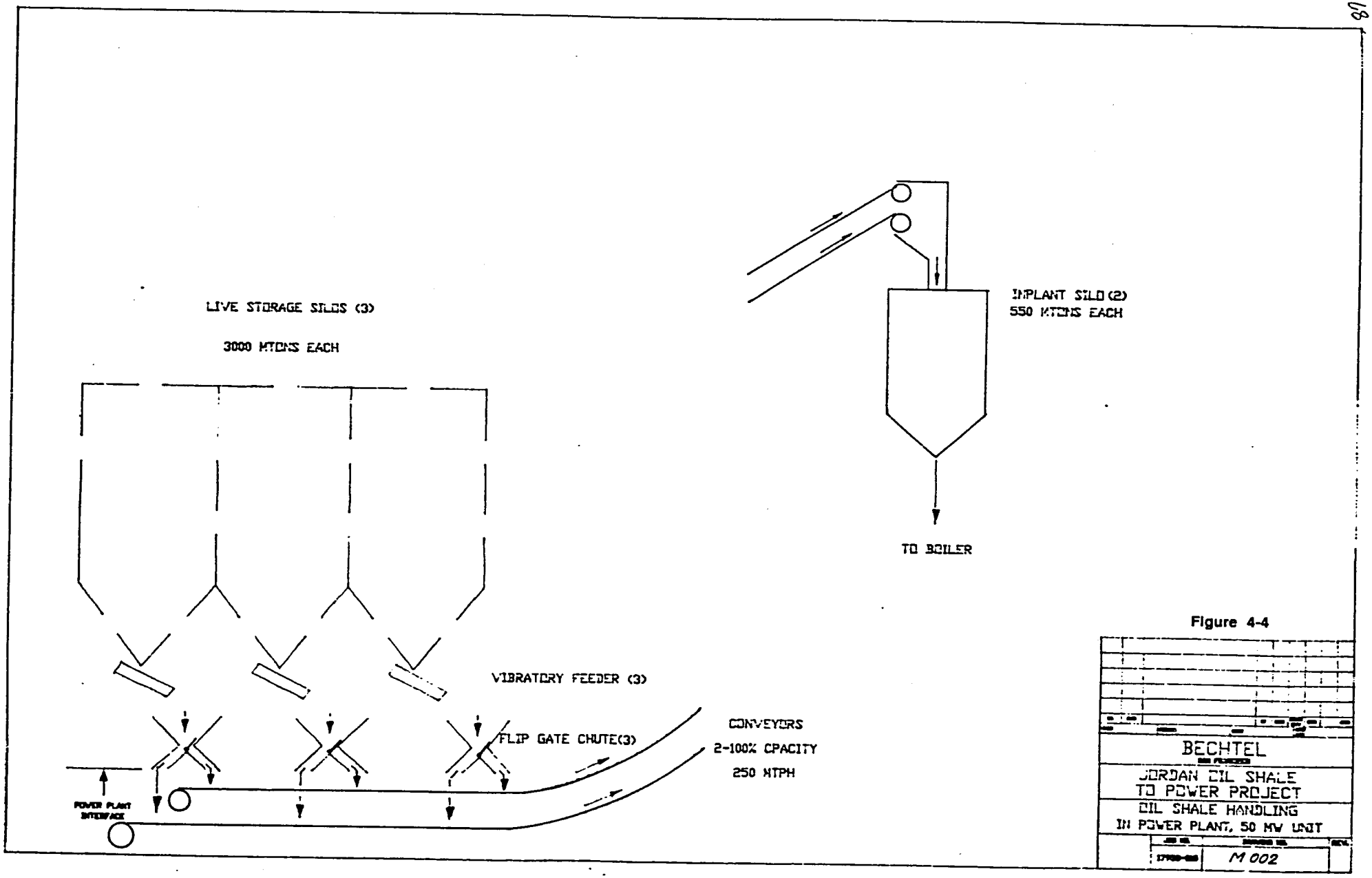

LIVE STORAGE SILOS (3)
3000 MTONS EACH
VIBRATORY FEEDER (3)
FLIP GATE CHUTE(3)
CONVEYORS
2-100% CPACITY
250 MTPH
POWER PLANT INTERFACE
INPLANT SILO (2)
550 MTONS EACH
TO BOILER
BECHTEL
JORDAN OIL SHALE
TO POWER PROJECT
OIL SHALE HANDLING
IN POWER PLANT, 50 MW UNIT
M 002

Figure 4-4

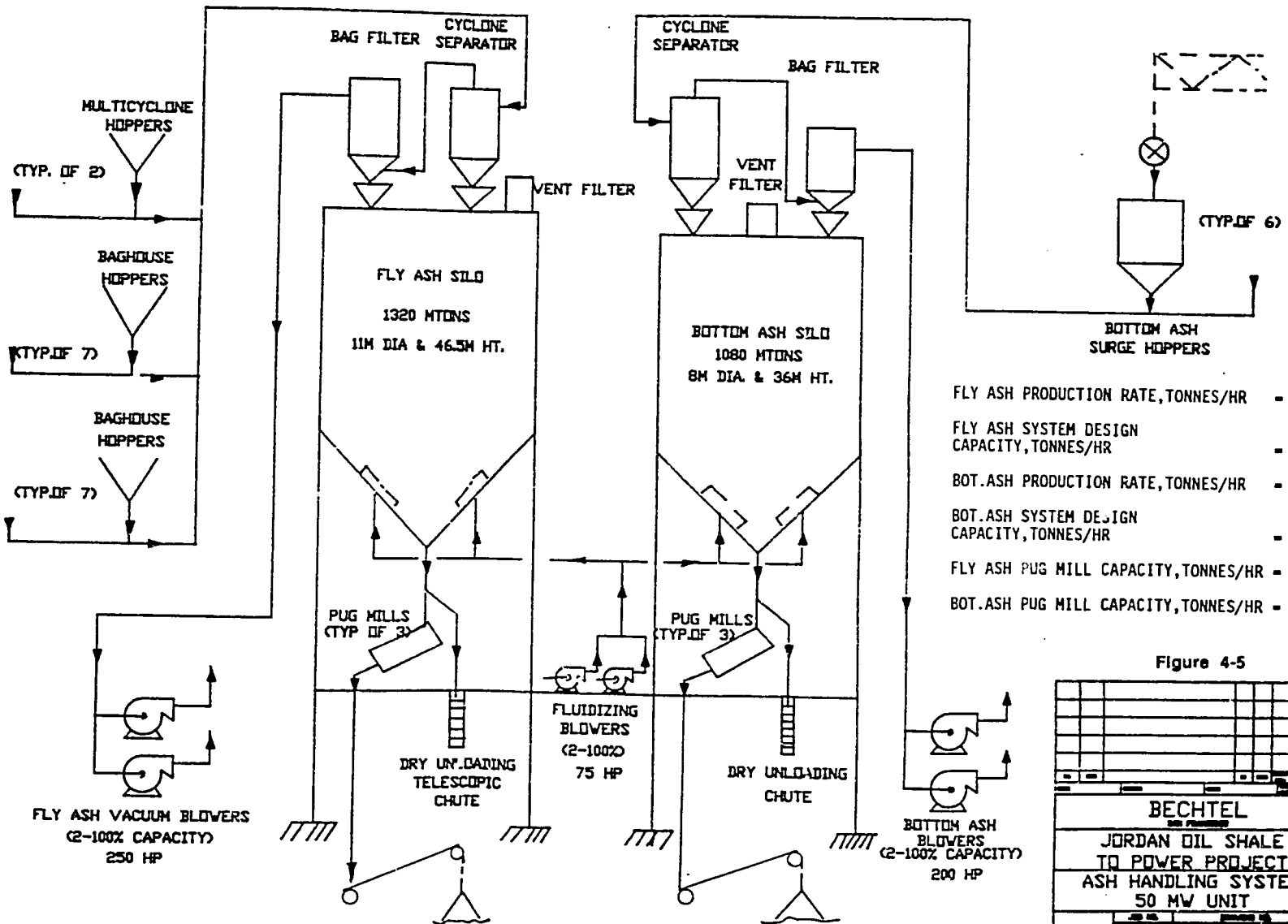
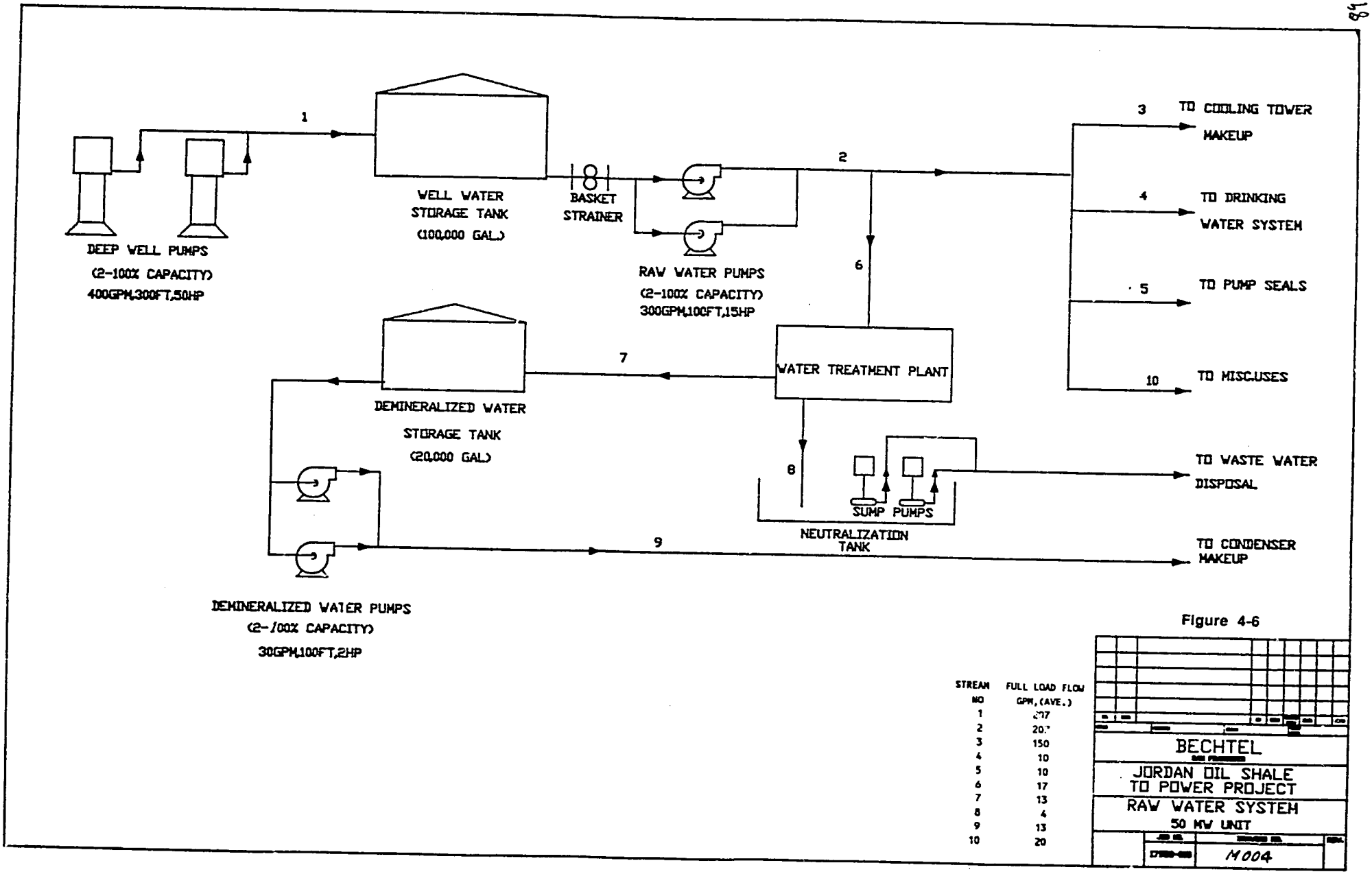

BAG FILTER
CYCLONE SEPARATOR
CYCLONE SEPARATOR
BAG FILTER
MULTICYCLONE HOPPERS
(TYP. OF 2)
VENT FILTER
VENT FILTER
(TYP.OF 6)
BAGHOUSE HOPPERS
(TYP.OF 7)
FLY ASH SILO
1320 MTONS
11M DIA & 46.5M HT.
BOTTOM ASH SILO
1080 MTONS
8M DIA. & 36M HT.
BOTTOM ASH SURGE HOPPERS
BAGHOUSE HOPPERS
(TYP.OF 7)
PUG MILLS (TYP OF 3)
PUG MILLS (TYP.OF 3)
FLUIDIZING BLOWERS (2-100%) 75 HP
DRY UNLOADING TELESCOPIC CHUTE
DRY UNLOADING CHUTE
FLY ASH VACUUM BLOWERS (2-100% CAPACITY) 250 HP
BOTTOM ASH BLOWERS (2-100% CAPACITY) 200 HP
FLY ASH PRODUCTION RATE,TONNES/HR - 55
FLY ASH SYSTEM DESIGN CAPACITY,TONNES/HR - 110
BOT.ASH PRODUCTION RATE,TONNES/HR - 45
BOT.ASH SYSTEM DESIGN CAPACITY,TONNES/HR - 90
FLY ASH PUG MILL CAPACITY,TONNES/HR - 85
BOT.ASH PUG MILL CAPACITY,TONNES/HR - 75
BECHTEL
JORDAN OIL SHALE TO POWER PROJECT
ASH HANDLING SYSTEM 50 MW UNIT
M003

Figure 4-5



STREAM NO	FULL LOAD FLOW GPM, (AVE.)
1	207
2	207
3	150
4	10
5	10
6	17
7	13
8	4
9	13
10	20

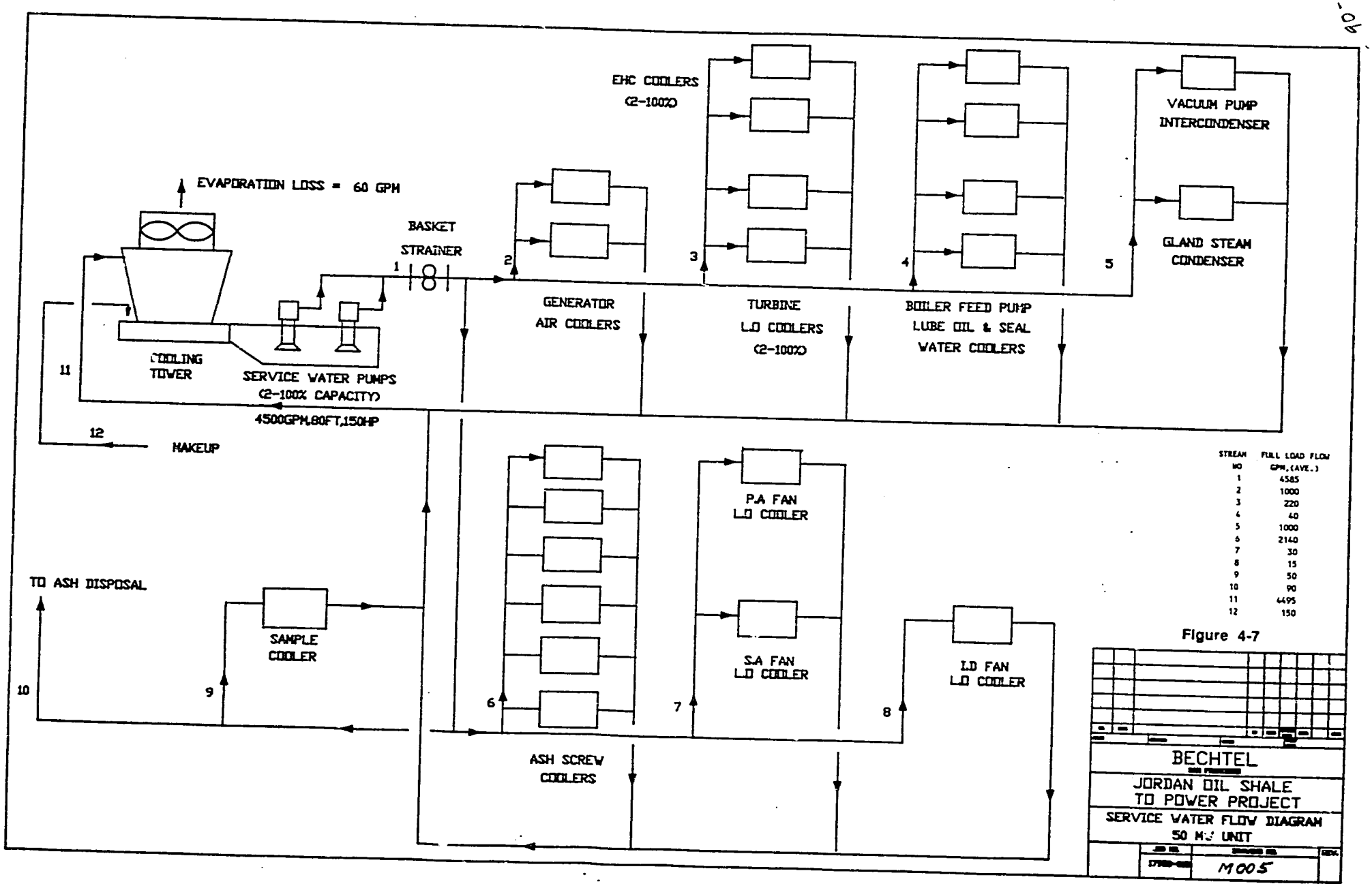
Figure 4-6

BECHTEL

JORDAN OIL SHALE
TO POWER PROJECT

RAW WATER SYSTEM
50 MW UNIT

M004



STREAM NO	FULL LOAD FLOW GPM.(AVE.)
1	4585
2	1000
3	220
4	40
5	1000
6	2140
7	30
8	15
9	50
10	90
11	4495
12	150

Figure 4-7

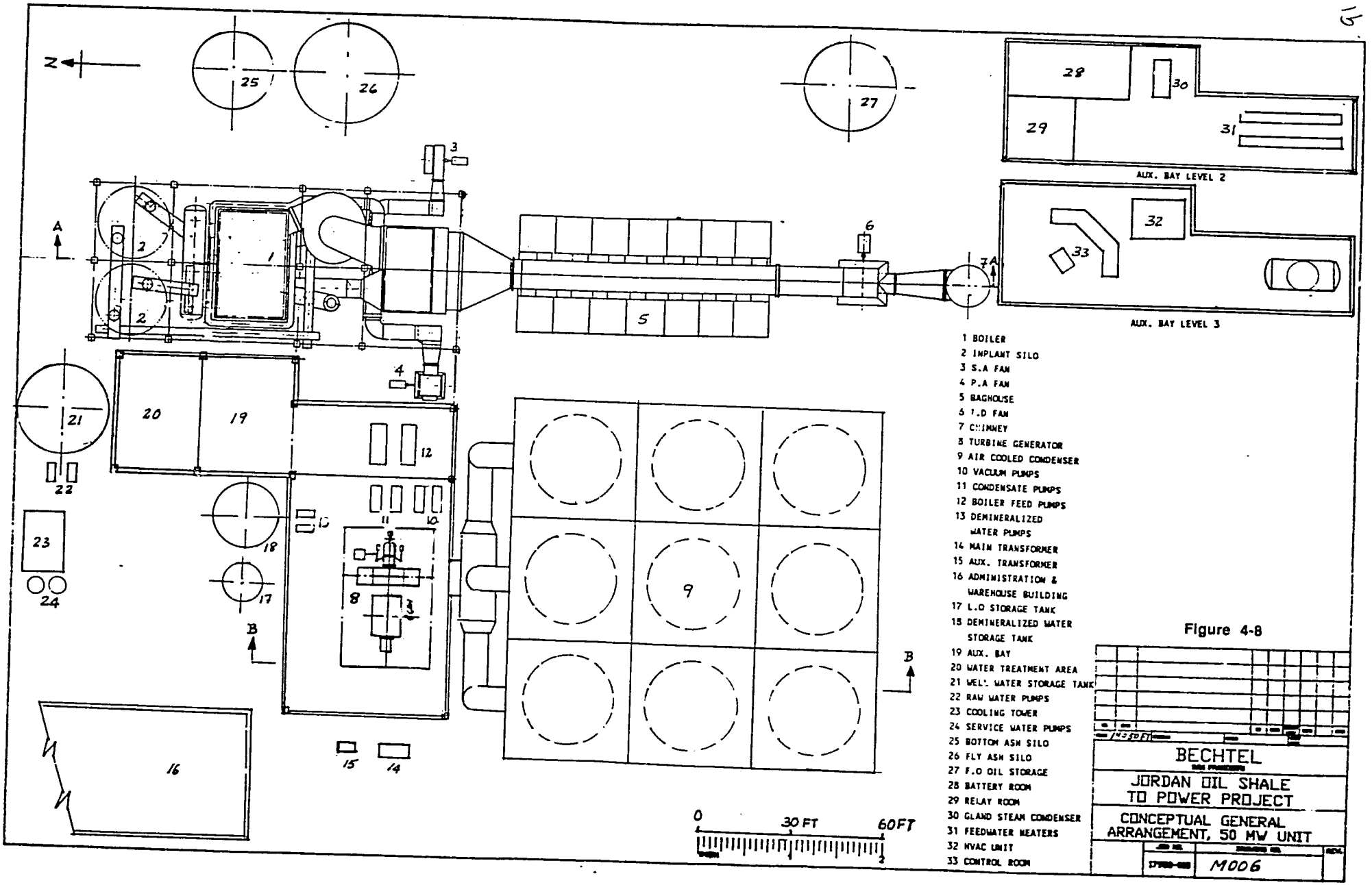
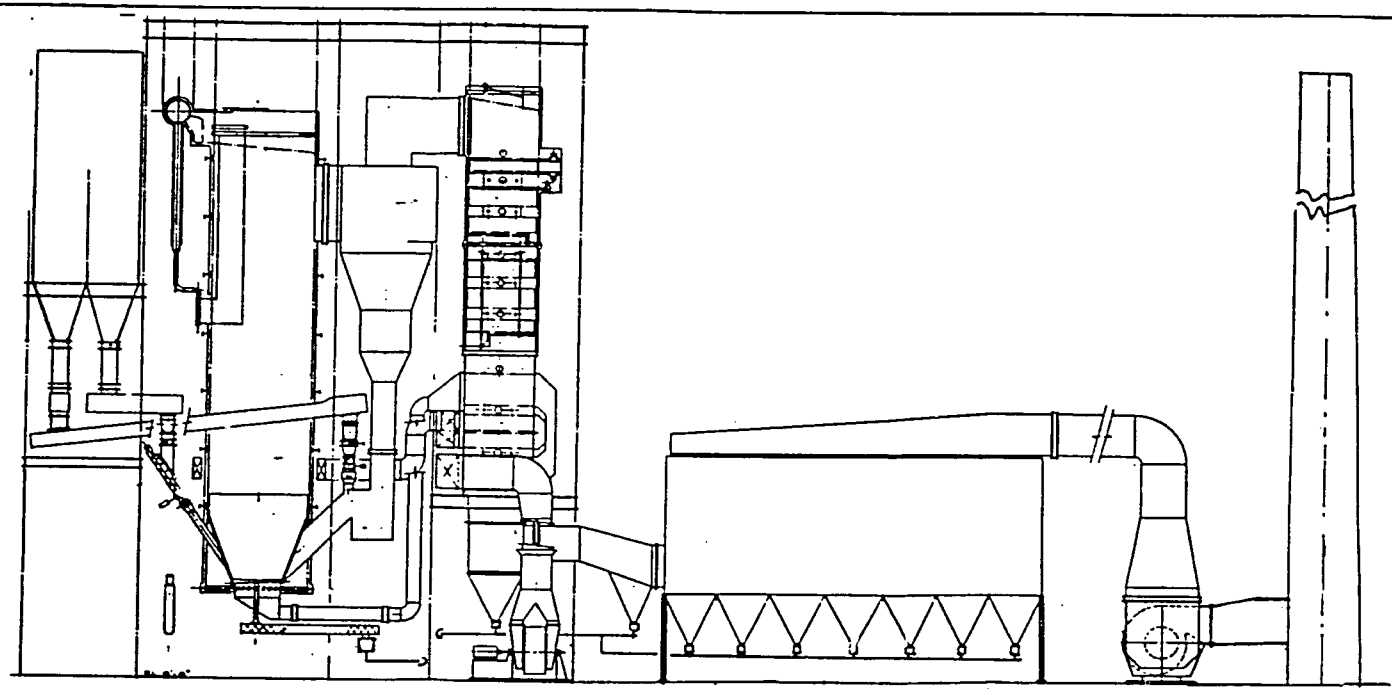
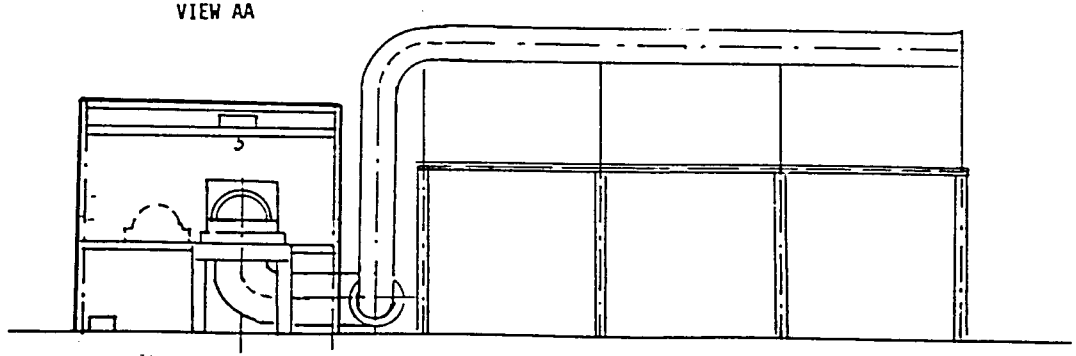

AUX. BAY LEVEL 2
AUX. BAY LEVEL 3
1 BOILER
2 INPLANT SILO
3 S.A FAN
4 P.A FAN
5 BAGHOUSE
6 I.D FAN
7 CHIMNEY
8 TURBINE GENERATOR
9 AIR COOLED CONDENSER
10 VACUUM PUMPS
11 CONDENSATE PUMPS
12 BOILER FEED PUMPS
13 DEMINERALIZED WATER PUMPS
14 MAIN TRANSFORMER
15 AUX. TRANSFORMER
16 ADMINISTRATION & WAREHOUSE BUILDING
17 L.O STORAGE TANK
18 DEMINERALIZED WATER STORAGE TANK
19 AUX. BAY
20 WATER TREATMENT AREA
21 WELL WATER STORAGE TANK
22 RAW WATER PUMPS
23 COOLING TOWER
24 SERVICE WATER PUMPS
25 BOTTOM ASH SILO
26 FLY ASH SILO
27 F.O OIL STORAGE
28 BATTERY ROOM
29 RELAY ROOM
30 GLAND STEAM CONDENSER
31 FEEDWATER HEATERS
32 HVAC UNIT
33 CONTROL ROOM
0 30 FT 60FT
BECHTEL
JORDAN OIL SHALE TO POWER PROJECT
CONCEPTUAL GENERAL ARRANGEMENT, 50 MW UNIT
M006

Figure 4-8



VIEW AA



VIEW BB

Figure 4-9

BECHTEL

RDAN OIL SHALE
POWER PROJECT

CONCEPTUAL GENERAL
ARRANGEMENT, 50 MW UNIT

M007

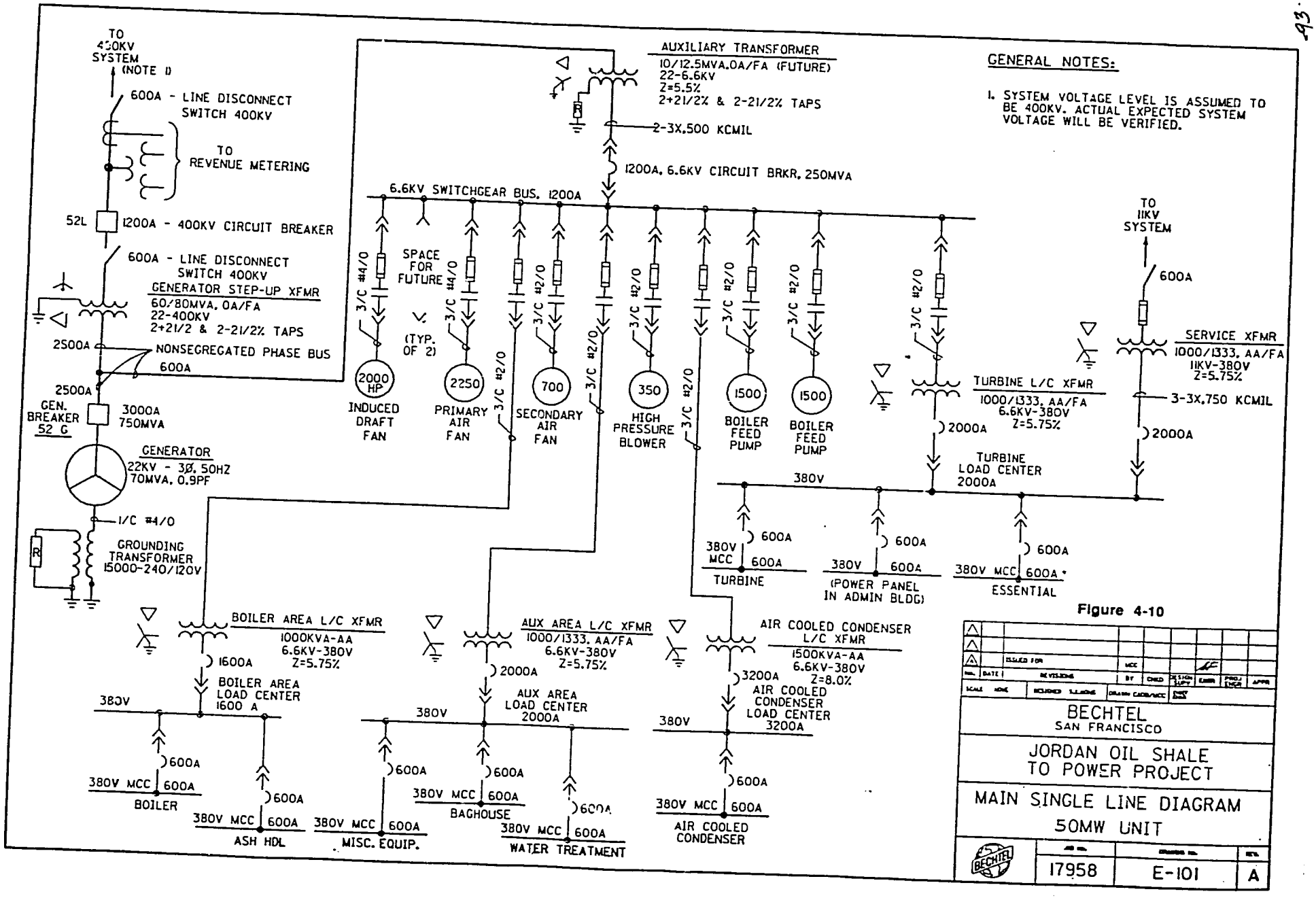

TO 400KV SYSTEM (NOTE 1)
600A - LINE DISCONNECT SWITCH 400KV
TO REVENUE METERING
52L
1200A - 400KV CIRCUIT BREAKER
600A - LINE DISCONNECT SWITCH 400KV
GENERATOR STEP-UP XFMR
60/80MVA, OA/FA
22-400KV
2+21/2 & 2-21/2% TAPS
2500A
NONSEGREGATED PHASE BUS
600A
2500A
GEN. BREAKER 52 G
3000A 750MVA
GENERATOR
22KV - 3Ø, 50HZ
70MVA, 0.9PF
1/C #4/0
GROUNDING TRANSFORMER
15000-240/120V
AUXILIARY TRANSFORMER
10/12.5MVA.OA/FA (FUTURE)
22-6.6KV
Z=5.5%
2+21/2% & 2-21/2% TAPS
2-3X.500 KCMIL
1200A, 6.6KV CIRCUIT BRKR, 250MVA
6.6KV SWITCHGEAR BUS, 1200A
3/C #4/0
SPACE FOR FUTURE
(TYP. OF 2)
3/C #2/0
2000 HP
INDUCED DRAFT FAN
2250
PRIMARY AIR FAN
700
SECONDARY AIR FAN
350
HIGH PRESSURE BLOWER
1500
BOILER FEED PUMP
1500
BOILER FEED PUMP
TURBINE L/C XFMR
1000/1333, AA/FA
6.6KV-380V
Z=5.75%
2000A
TURBINE LOAD CENTER 2000A
380V
600A
380V MCC 600A
TURBINE
380V 600A
(POWER PANEL IN ADMIN BLDG)
380V MCC 600A
ESSENTIAL
TO 11KV SYSTEM
600A
SERVICE XFMR
1000/1333, AA/FA
11KV-380V
Z=5.75%
3-3X.750 KCMIL
2000A
BOILER AREA L/C XFMR
1000KVA-AA
6.6KV-380V
Z=5.75%
1600A
BOILER AREA LOAD CENTER 1600 A
380V
380V MCC 600A
BOILER
380V MCC 600A
ASH HDL
AUX AREA L/C XFMR
1000/1333, AA/FA
6.6KV-380V
Z=5.75%
2000A
AUX AREA LOAD CENTER 2000A
380V MCC 600A
BAGHOUSE
380V MCC 600A
MISC. EQUIP.
380V MCC 600A
WATER TREATMENT
AIR COOLED CONDENSER L/C XFMR
1500KVA-AA
6.6KV-380V
Z=8.0%
3200A
AIR COOLED CONDENSER LOAD CENTER 3200A
380V MCC 600A
AIR COOLED CONDENSER
GENERAL NOTES:
1. SYSTEM VOLTAGE LEVEL IS ASSUMED TO BE 400KV. ACTUAL EXPECTED SYSTEM VOLTAGE WILL BE VERIFIED.
BECHTEL
SAN FRANCISCO
JORDAN OIL SHALE TO POWER PROJECT
MAIN SINGLE LINE DIAGRAM
50MW UNIT
17958
E-101
A

Figure 4-10

4.6 COST ESTIMATES

This section presents order of magnitude estimates of capital cost, first year operation and maintenance costs of the electricity generating facility.

The cost estimate methodology and the approach used to prepare them are described in the following paragraphs.

4.6.1 Installed Power Block Capital Cost

Cost Estimate Methodology. The total power plant capital cost is comprised of the summation of the total plant cost and Owner's cost. This study addresses only the total plant facilities cost component of power plant cost. An allowance also has been made for Owner's cost.

The total plant cost is the sum of:

- Total field cost
- Engineering and home office services
- Project contingency

Total Field Cost. The total field cost is the total constructed cost of all on-site processing and generating unit costs (within the boundary of power block) including all direct and include materials, labor and subcontract costs, plus distributables costs.

The estimated distributables costs include such costs as field supervision, temporary facilities, temporary utilities and construction equipment and services.

Engineering and Home Office Services. All costs are included for design engineering and drafting, estimating, cost control, planning and scheduling; purchasing, expediting and inspection; administrative services, home office start-up, construction management, labor relations, accounting; legal and other general services.

Table 4-5

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
CONCEPTUAL INTEGRATED 50 MW PLANT
SUMMARY OF COSTS
($ in 1000, Mid-1988 Price Level)

		COST $
A)	POWER PLANT:	
	Inplant Fuel Handling	$ 1,200
	Steam Generator + Stack + Baghouse	46,900[a]
	Turbine, Cond, F/Wtr, Etc.	16,900
	Ash Handling	1,500
	General Facilities:	
	Tankage	500
	Cooling System	2,000
	Fire Protection	1,200
	Waste Water	500
	Electrical	3,700
	Control/Instrumentation	2,200
	Site Improvement	1,400
	Miscellaneous	3,100
	Building:	
	Turbine	800
	Boiler Foundation and Structure	4,600
	Auxiliary/Control	1,100
	Water Treatment	200
	Admin/Warehouse	1,100
	Yard Facility	300
	Services Building	900
	Switch Yard:	1,700
	Sub Total Plant Cost:	$ 91,800
	Owner's Cost/Working Allowance for Funds During Construction:	$ 15,800
	Other's Allow (see 4.6.1):	$ 4,600
	Sub Total Owner's Capital Costs:	$ 20,400
	TOTAL POWER PLANT COSTS:	$112,200
B)	ALLOWANCE FOR OFF-SITE INFRASTRUCTURE:	$ 15,000
C)	MINING & SHALE PROCESSING EQUIP & FACILITIES COSTS: (From Table 4-1)	$ 35,115
D)	ASH & OVERBURDEN WASTE DISPOSAL (Table 4-2):	$ 2,315
	TOTAL INSTALLED PROJECT CAPITAL COSTS: (50/50 Debt/Equity)	$164,630
	TOTAL INSTALLED PROJECT CAPITAL COSTS: (80/20 Debt/Equity)	$166,612

(a): Includes $26,500,000 for boiler cost from Pyropower adjusted for Jordan location.

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Project Contingency. The project contingency is a capital cost contingency that covers the cost of additional equipment or other costs that would result from a more detailed design of a definite site specific project. An allowance of 15 percent of Total Field + Engineering and Home Office was provided.

Owner's Cost. To complete the entire project the cost of the following items are to be included as a part of Owner's cost.

These items include:

a. Allowance for funds used during construction from the center of gravity of expenditures until the plant is in commercial operation.

b. An allowance for preproduction start-up costs including training, inventory, working capital and initial chemicals charges.

Cost Estimating Approach. The estimating approach used in this study includes maximum use of existing estimating data from a similar plant which has been recently engineered and constructed by Bechtel.

The cost estimate basis for major equipment, other materials and labor were developed by comparison with previous similar work and analysed by Bechtel on an overall project and system basis. In this Prefeasibility Study no vendors quotation were obtained for major equipment items except the boiler.

Installation manhours and costs have been adjusted to reflect those costs which can be expected at the specified site's geographic location. The labor costs are supplemented by data received from the Jordan Electricity Authority.

Capital Cost Estimate. The capital cost estimate for power plant is shown under Item (A) in Table 4-5. The capital cost has been developed in accordance with the scope and technical specifications described in Section 4.4. In developing these estimates the cost impact on major equipment purchased in the worldwide market and maximum use of locally available materials and labor has been assumed. This recognizes the indigenous craft skills developed on existing thermal power plants in Jordan. The capital cost for the 50 MW project is considered to have an accuracy of ±25 percent.

Cost Estimate Qualifications and Assumptions:

- All costs are mid-1988 price level.
- Allowance of funds during construction has been based on 10%/yr. per JEA.
- Any future escalation during construction is excluded.
- A boiler price based on an adjusted Pyropower Corporation quotation.
- A 48 hour week and composite direct manual wage rate of $3.00/hr. is assumed for power plant construction. This information was provided by JEA.
- It is assumed that foundations will be on spread footings.
- It is assumed that oil shale will be delivered at inplant silos sized and ready for burning.

Other assumptions have been made as follows:

- Licensing or environmental regulatory requirement will not restrain the engineering/procurement/construction schedule.
- Extremes of climatic conditions are not expected to occur at the site area.
- Construction supervisors/advisors would be provided by suppliers of imported major equipment such as boiler and turbine generator.
- Availability of a qualified labor force in the number and skills required.
- Conversion rate of one JD is equivalent to $3 USD.

All Owner's costs as described below are excluded:

- Land and right-of-way
- Permits and licenses
- Local Taxes
- Import taxes

The following Owner's costs are covered as an allowance added to the facilities cost:

- Owner's administrative and overhead cost
- Owner's consultants and related costs
- Costs of utilities for construction
- Spare parts
- Training of operating personnel

4.6.2 Cash Flow

The boiler plant installation cash flow is based on the anticipated project schedule for construction in the early 1990s with USA or other foreign purchased equipment, and reflects construction conditions and labor availability in Jordan. The cash flow was plotted with an estimated percentage of expenditure of total capital cost versus the percentage of time of completion of the project. The cost curve for power block only is presented in Figure 4-11.

A two year mine development program parallels the power block construction.

4.6.3 Power Block Operating Requirements

Estimates covers first year operating costs for power plant only.

First year operating costs, are presented in Table 4-6. All costs are at the mid-1988 price level.

Total first year operating costs include fixed and variable operating and maintenance costs, fuel (oil shale) costs. An explanation of each item follows.

Fixed O&M Costs. Fixed O&M costs include both operating labor and maintenance labor plus materials to operate the power plant. The average labor rate employed, corresponding to a direct labor charge plus payroll additives, is $3.00/hr. The staffing requirement for power plant operation is presented in Table 4-7.

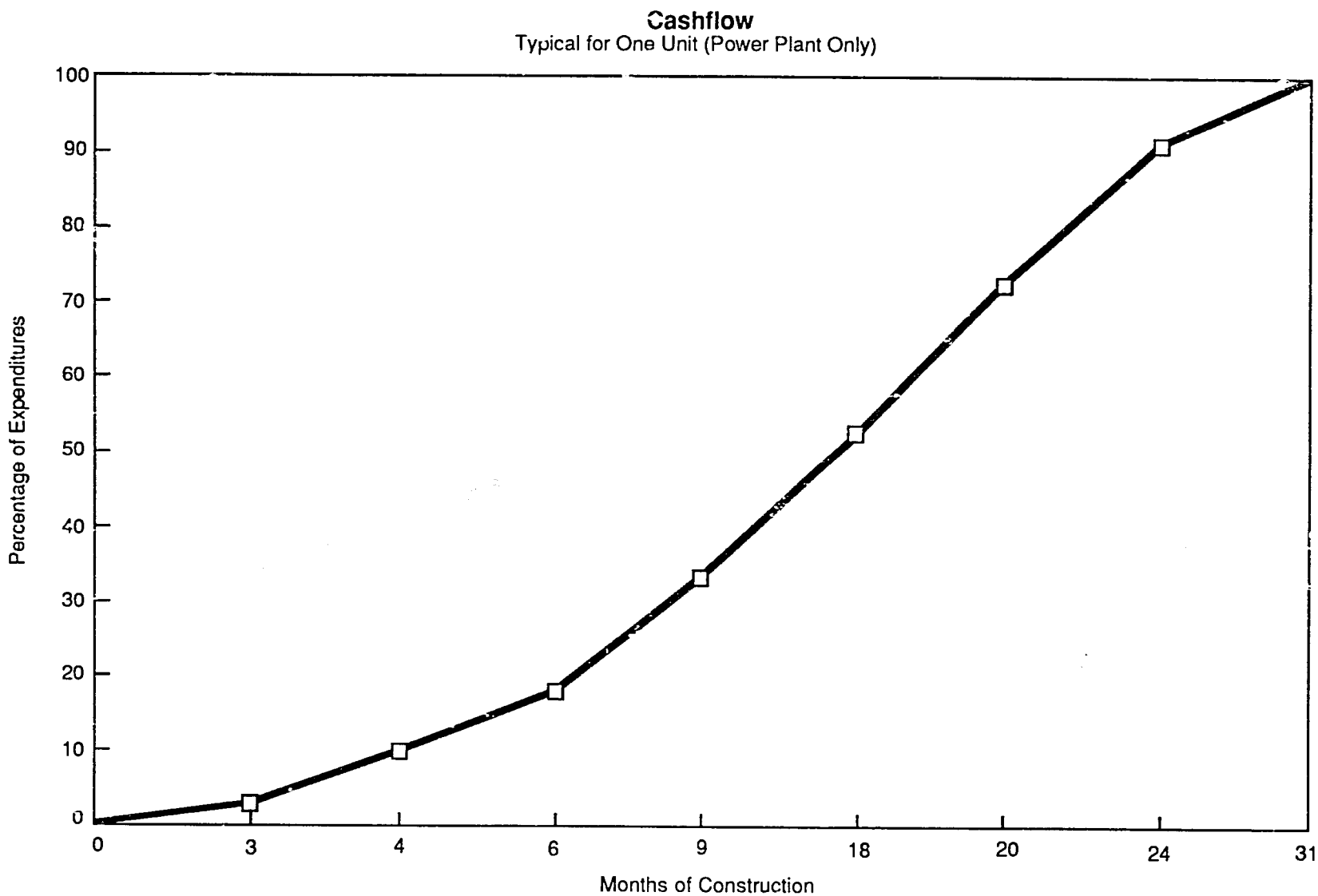


Figure 4-11 Power Block Capital Expenditures – 50 MW and 20 MW

Annual maintenance costs are estimated as a percentage of the total plant cost (TPC). This percentage varies widely depending on the nature of the processing conditions and type of power plant. The rate of 1.50 percent was selected for this facility. This rate was established by a survey of 456 conventional coal fired power units. (A somewhat higher rate may be needed for a fluid bed boiler - hence an allowance is provided).

Maintenance labor is typically 40 percent and maintenance material 60 percent of the total maintenance cost. Administrative and support labor is assumed to be 30 percent of the operating and maintenance labor.

Variable O&M Costs. Variable O&M costs include the following:

- Variable maintenance costs in addition to the fixed maintenance costs are estimated to be 1 mill per kilowatt hour of operation.
- Utility costs of process water are $0.20 per one thousand gallons. Steam and electricity for plant use are not included as direct costs, but rather impact the plant heat rate.
- General plant chemical costs are estimated as an allowance.
- Disposal of ash by truck haul to a dedicated waste disposal area including loading costs at the power plant, hauling, dumping, spreading, is estimated to cost -

  a) At debt/equity 50/50 - $1.01/ton

  b) At debt/equity 80/20 - $0.89/ton

Fuel Costs. Fuel (oil shale) costs are an additional variable operating cost. The oil shale costs include both mining cost and crushing/handling costs and are as follows:

a) At debt/equity 50/50 - $13.48/ton

b) At debt/equity 80/20 - $11.88/ton

Table 4-6

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
CONCEPTUAL INTEGRATED 50 MW PLANT
OPERATING REQUIREMENTS - 1ST YEAR

A. DEBT / EQUITY RATIO :========== 50/50

NET GENERATION -	MWe	51.5
CAPACITY FACTOR -	%	75%
ANNUAL GENERATION	MKWh/YR	338
SUB TOTAL PLANT COSTS (TPC)		$91,800

FIXED O & M COSTS:	MH	$ /MH	FIRST YEAR COST$1,000
OPERATING LABOR :	194,688	$3	$600
MAINTENANCE LABOR :			
@ 40.00% of	1.50%	OF TPC	551
MAINTENANCE MATERIAL :			
@ 60.00% of	1.50%	OF TPC	826
ADMIN LABOR :	30.00%	OF O & M LABOR	345
SUB TOTAL FIXED O&M COSTS:			$2,322

VARIABLE O & M COSTS:	QUANTITY	UNIT COST	
VARIABLE MAINTENANCE	338 MKWh	1 MILL/KWH	$338
PROCESS WATER	1,400,000 GALLON	$0.2/GAL	$280
GENERAL PLANT CHEMICALS		ALLOW	50
FUEL OIL	165,000 GALLON	$0.35/GAL	$58
WASTE DISPOSAL (Section 4.2.7)	815,000 TN/YR	$1.01/TN	$823
SPECIAL BOILER MAINT		ALLOW	200
SUB TOTAL VARIABLE O&M COSTS:			$1,749
TOTAL FIXED & VARIABLE O&M COSTS:			$4,071
OIL SHALE FUEL (Section 4.2.5)	973,000 TN/YR	$13.48 $/TN	$13,116

B. DEBT / EQUITY RATIO :========== 80/20

TOTAL FIXED & VARIABLE O&M COSTS (W/O ASH DISPOSAL)			$3,248
WASTE DISPOSAL (Section 4.2.7)	815,000 TN/YR	$0.89 $/TN	$725
TOTAL FIXED & VARIABLE O&M COSTS :			$3,973
OIL SHALE FUEL (Section 4.2.5)	973,000 TN/YR	$11.88 $/TN	$11,559

Table 4-7

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
CONCEPTUAL POWER BLOCK 50 MW PLANT

JOB DESCRIPTION	WEEK DAY	WEEK END	SWING	NIGHT	TOTAL
OPERATION					
SUPERINTENDENT	1				1
SHIFT FOREMAN	3	3	3	3	12
FUEL SUPPLY SUPERVISOR	1				1
TECHNICAL SUPERVISOR	1				1
CONTROL ROOM OPERATOR	2	2	2	2	8
CONTROL ROOM TECHNICIAN	2	2	2	2	8
PLANT CHEMIST	1				1
LAB TECHNICIAN	2				2
BOILER OPERATOR	2	2	2	2	8
MISC. OPERATOR	2	2	2	2	8
FUEL MAN	2	2	2	2	8
HELPER OPERATOR	3	3	3	3	12
ENGINEER	2	2	2	2	8
TOTAL OPERATORS	24	18	18	18	78

TOTAL OPERATOR/SHIFT (AVERAGE) 22 MAN/SHIFT

TOTAL MAINTENANCE STAFFS/SHIFT 21 MAN/SHIFT

TOTAL O&M PER SHIFT 43 MAN SHIFT

Staff Required	
Operations	78
Maintenance	73
TOTAL	151

4.6.4 Busbar Cost of Electricity

Employing the previously developed costs, an estimate of busbar costs of electricity is presented in Table 4-8 for the first year of operation. Levelized costs for future years operations were not created because it is visualized that this project is a demonstration operation only.

It should be noted that an approximate 15 percent capital charge used for the power block facilities is typical of the capital charge rate for many USA utility installations. It is the equivalent of a 9 percent interest rate on the borrowed capital component plus a 13.5 percent return on the equity component, plus depreciation, insurance and tax charges for the various equipment categories and facilities involved (see Table 6-9). Using EPRI procedures for calculation of fixed charge rates on capital for the two debt/equity ratios selected for this analysis we developed the following rates:

Debt/Equity Ratio	Capital Charge Rate
50/50	15.3
80/20	13.9

The oil shale fuel cost was computed using fixed capital rates of 10 percent interest on borrowed capital component plus a 20 percent return on the equity component. This is more typical of mining venture capital charges.

The off-site infrastructure investment was assumed to be self liquidating and is not included in the Busbar rate calculations.

Table 4-8

BREAKDOWN AND SENSITIVITY OF POWER COSTS TO CAPITAL AND OPERATING COST COMPONENTS

CONCEPTUAL INTEGRATED 50 MW PLANT

DEBT/EQUITY RATIO : 50/50	1ST YEAR	
	$1,000	MILLS/KWH
Capital Charges @ 15.3% (Power Block)	$17,167	51
Operation & Maintenance	4,071	12
Fuel - Oil Shale	13,116	39
Total Busbar Cost:	$34,354	102

DEBT/EQUITY RATIO : 80/20	1ST YEAR	
	$1,000	MILLS/KWH
Capital Charges @ 13.9% (Power Block)	$15,596	46
Operation & Maintenance	3,973	12
Fuel - Oil Shale	11,559	34
Total Busbar Cost:	$31,128	92

Notes:
- o Capital charges include Power Plant only.
- o Fuel - Oil shale includes capital charges for Mining & Material Handling Plant.

Section 5
Integrated 20 MW Plant Conceptual Designs & Cost

Section 5

INTEGRATED 20 MW PLANT CONCEPTUAL DESIGNS AND COSTS

5.1 INTRODUCTION

The original approved Work Scope for the Prefeasibility Study included preparation of conceptual designs and costs for a 20 MW Demonstration Project.

At the conclusion of the Prefeasibility Study - if it is decided to proceed into the next phase of oil shale development - a decision must be made on whether to focus attention on a higher investment 50 MW project or a lower investment cost 20 MW project whose power product will need a substantial subsidy from the Government of Jordan.

The following subsections describe the facilities and costs involved with an Integrated 20 MW Project.

5.2 MINE AND MATERIALS HANDLING

Details of the mine plan and shale processing plan are presented in the Mining Report (Appendix 5).

Figure 4-1 shows the layout of mine and shale processing facilities relative to the power block facilities.

The mining and material handling plans for the 20 MW plant will be the same as that for the 50 MW plant described in Section 4.2 except that less material is mined and processed and fewer shifts are required to do the work.

5.2.1 Mine Development Plan

If the 20 MW plant were selected over the 50 MW plant, there will not be any changes in the development of a mine for this plant. The trial pit would be developed into a truck and loader operation during the power plant construction.

The only difference in the mine development for the 50 MW plant as described in Section 4.2.1 and the 20 MW plant is the size of the box-cut. The box-cut for this mine will be 60 metres wide and 85 metres long exposing approximately 125,000 tonnes of oil shale. The amount of overburden removed will be 500,000 bank cubic metres.

5.2.2 Mine Operation

The energy input to the boiler is 294.8 x 10^6 Btu per hour which is equivalent to 59.42 tonnes per hour of the performance fuel. The annual fuel requirement based at a 100 percent capacity factor is 520,519 tonnes and at a 75 percent capacity factor 390,389 tonnes are required.

The mine is designed to meet the fuel requirement of the power plant when it operates at 100 percent capacity factor.

The mine will be scheduled to operate 300 shifts per year and will have the capability of delivery oil shale to the processing plant at a rate of 250 tonnes per hour when operating at an overall efficiency of 87 percent. The higher efficiency is expected for this operation because equipment will be available for maintenance during the second shift. Overburden removal rate will be consistent with that required for an average annual operating capacity factor of 75 percent for the power plant or approximately 500,000 bank cubic metres annually.

5.2.3 Oil Shale Processing

The same facilities described in Section 4.2.3 are used for the oil shale processing of the 20 MW plant. The processing plant will be scheduled for 300 shifts per year and will have a design capacity of 250 tonnes per hour when operating at an efficiency of 87 percent. The three steel storage silos for this plant are smaller than those of the 50 MW plant, 10 metres diameter by 20 metres high is 13 metres diameter by 30 metres high. (See Figure 5-1.)

5.2.4 Mine Services Facility

There aren't any changes to these facilities as described in Section 4.2.4.

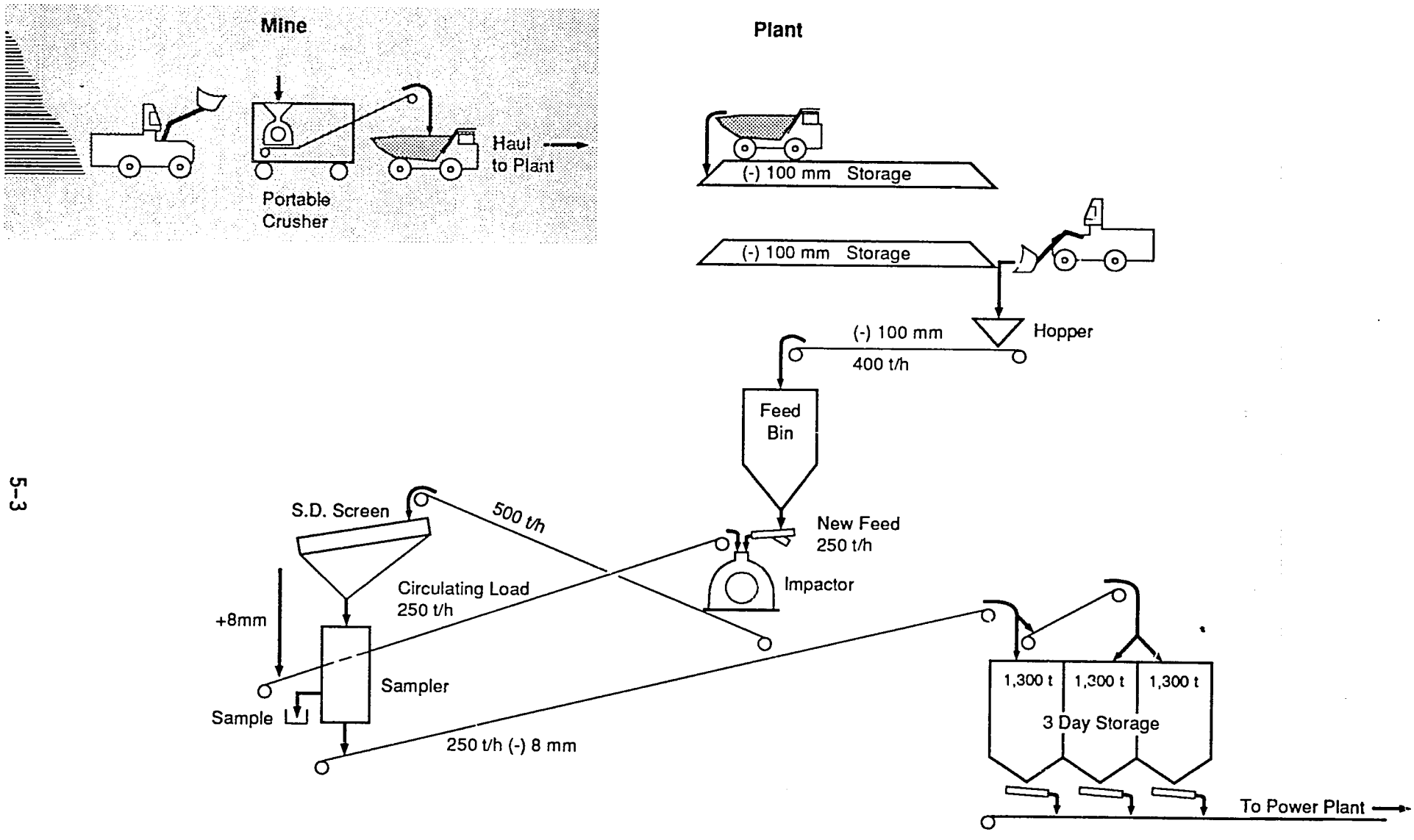


Figure 5-1 Flow Sheet – Oil Shale Processing Plant
20 MW Demonstration Plant

5.2.5 Mining and Processing Economics

The same details described in Section 4.2.5 for the 50 MW plant were performed for the 20 MW plant. The summary of the cash flow analysis is presented in Table 5-1.

Table 5-1

SUMMARY of 20 MW PLANT OIL SHALE
MINING AND SHALE PROCESSING COSTS

	50/50 Debt-Equity US $1,000	80/20 Debt-Equity US $1,000
Capital Cost		
Mine Development	4,900	4,900
Mine Equipment	11,090	11,090
Process Plant Facilities	6,945	6,945
Spare Parts	1,200	1,200
Working Capital	1,200	1,200
Capitalized Interest During Construction	2,534	4,054
TOTAL	27,869	29,389
Operating Costs and Other Costs		
Annual Cost (weighted average)	6,827	5,582
Product Mined and Processed		
Annual Tonnes x 1000	390	390
Unit Cost		
US $/Tonne (weighted average)	17.50	14.31
US $/$10^6$Btu (weighted average)	3.53	2.89

5.2.6 Spent Shale Ash Disposal

The spent shale ash disposal for the 20 MW plant will be handled in the same manner described for the 50 MW plant in Section 4.2.6.

At 100 percent capacity the power plant will produce 40 tonnes per hour of shale ash and after wetting in a pug mill with 20 percent water by weight, this will amount to 50 tonnes per hour. The haulage of this spent shale ash will be handled from the mine truck fleet. The loading of the truck will be by a front end loader assigned to this duty.

5.2.7 Spent Shale Disposal Economics

Details of the spent shale ash disposal economics for the 20 MW plant are found in the Mining Report (Appendix 5).

The summarary of the cash flow analysis for this operation is presented in Table 5-2.

Table 5-2

SUMMARY OF 20 MW PLANT SPENT SHALE ASH DISPOSAL COSTS

	50/50 Debt-Equity US $1,000	80/20 Debt-Equity US $1,000
Capital Cost		
Equipment	1,431	1,431
Spare Parts	50	50
Working Capital	60	60
Capitalized Interest During Construction	77	123
TOTAL	1,618	1,664
Operating Costs and Other Costs		
Annual Cost (weighted average)	394	316
Spent Shale Ash Hauled		
Annual Tonnes x 1,000	327	327
Unit Cost		
US $/Tonne (weighted average)	1.20	0.97

-110

5.2.8 Operating Requirements

The manpower and utility requirements of the 20 MW mine and shale processing facilities are as follows:

- Total men - 75 (including 2 expatriates)
- Purchased power - 7,200,000 Kwh/year
- Water (ex ash wetting)- 1,515,000 liters/day
  - 455,000 cubic meters/year

5.2.9 Contract Mining Option

The foregoing conceptual mine and shale processing design contains the normal contingencies and spare capacity that are built into a grassroots project serving a substantial downstream investment in power block faciliies. If it is decided to build this 20 MW Integrated Project as a 1 to 2 year demonstration project, then a separate study should be made of the investment savings that might be made in the mining facilities plan.

One option might be to operate the Demonstration Project with a contract mining program employing idle equipment said to be available in Jordan. Insufficient data were available about the present condition of such equipment and any costs required for equipment rehabilitation. Because of study budget limitations, consideration of savings that might accrue with contract mining has been deferred until a follow-on development phase.

The use of contract mining is unlikely to significantly change the economic prospects for the 20 MW project.

5.3 BOILER PLANT - 20 MW PROJECT

Appendix 10 presents the Pyropower Corp. report on its design for the Pyroflow Process fluid bed boiler facilities.

Because the boiler design is considered to contain proprietary information, only an expurgated version of the design is contained in the Appendix. Under a confidentiality agreement, Bechtel received sufficient boiler plant design

details to prepare a conceptual plan and an order of magnitude cost estimate for these boiler facilities for inclusion in the integrated overall project cost estimate and economic evaluation.

The reader is referred to the following Sections 5.4 and 5.6 for further details on integration of the boiler into the power block design and operation.

5.4 POWER PLANT DESCRIPTION

The following sections describe the conceptual design of a 20 MW nominal capacity oil shale-fired power plant and auxiliaries located within the power plant boundaries. The design bases and assumptions used for the conceptual design are listed in Appendix 11A. A list of major equipment with design ratings for the power plant is included in Appendix 11B.

5.4.1 Thermal Cycle See Section 4.4.1.

The turbine throttle flow is 90,700 kg/hr (200,000 lb/hr) at the design point.

A heat balance cycle diagram is included as Figure 5-2 at the end of this section.

5.4.2 Selection of Turbine Throttle Conditions See Section 4.4.2.

5.4.3 Steam Cycle Description See Section 4.4.3.

5.4.4 Boiler

The boiler is described in Section 4.3 in detail. A circulation fluidized bed, oil shale-fired, balanced draft, drum type boiler is used. The steam conditions at the superheater outlet are:

Flow	90,700 kg/hr (200,000 ms/hr)
Pressure	109.9 kg/sq cm Abs (1563.5 psia)
Temperature	512.8°C (955°F)

The analysis of oil shale is shown in Table 2 of Appendix A. At design conditions, the boiler heat input is 294.8 million Btu/hr and consumes about 59.4 tonnes (65.5 tons) per hour of oil shale having a higher heating value of

1250 Kcal/kg (2250 Btu/lb). No. 2 fuel oil is required for starting the boiler and each start-up requires about 4,400 gallons of No. 2 fuel oil (diesel).

5.4.5 Overall Plant Performance

The expected overall plant performance at design conditions is summarized in Table 5-3.

The air-cooled condenser pressure varies with the ambient temperature. For the same boiler heat input, the turbine gross output varies with the condenser pressure. For example, the gross MW output is expected to be 23.1 MW at 6.5 inches HgA condenser pressure and 22.4 MW at 9 inches HgA condenser pressure. The steam turbine should be operated with condenser pressure less than 9 inches HgA. The unit output should be reduced if the condenser pressure rises above 9 inches HgA during high ambient temperature conditions.

Assuming an annual average ambient dry bulb temperature of 16°C (61°F) and 75 percent plant capacity factor, expected annual performance of the unit is summarized in Table 5-4.

5.4.6 Power Plant Fuel Handling System See Section 4.4.6 and Figure 5-3 at the end of this section.

5.4.7 Power Plant Ash Handling System See Section 4.4.7 and Figure 5-4 at the end of this section.

5.4.8 Plant Water Systems

The plant water system consists of the raw water system, the treated plant makeup system and the plant service water system.

Recognizing that the plant is located in a desert area and that availability of water is limited to less than 2 million cubic meters per year, a dry cooling tower is used for removing heat from the steam turbine exhaust. A small wet cooling tower is used to reject heat to the atmosphere from plant auxiliaries such as ash coolers, etc.

Table 5-3

PLANT PERFORMANCE AT DESIGN CONDITIONS

1.	Boiler heat input, 10^6 Btu/hr	294.8
2.	Boiler efficiency %	76.07
3.	Boiler steam output, lbs/hr	200,000
3.	Turbine throttle conditions, psia	1463.5
4.	°F	950
5.	Design condenser pressurre, inches HgA (Expect 3.5 inches HgA annual average pressure at ambient conditions)	5.5
6.	Plant gross output at 5.5 in HgA condenser pressure, MW	23.4
7.	Auxiliary power consumption, MW	3.65
8.	Plant net output, MW	19.75
9.	Plant net heat rate, Btu/Kwh (Efficiency = 23.0%)	14,927
10.	Design fuel consumption, lbs/hr	131,000
11.	Plant water consumption, gpm	102
12.	Total ash production, lbs/hr	87,500

Table 5-4

EXPECTED ANNUAL PERFORMANCE OF THE UNIT

1.	Plant net output at annual average condenser pressure of 3.5" HgA, MW	20.5
2.	Annual net, Kilowatthours	134.69×10^6
3.	Annual fuel consumption, tonnes	390,400
4.	Annual ash production, tonnes	260,700
5.	Annual fuel oil consumption, gallons	50,000
6.	Annual water consumption, gallons	675,000
	, cubic meters	2,600

The raw water system consists of two 100 percent capacity deep well pumps, each rated at 200 gpm at an assumed head of 300 ft. See Figure 5-5 at the end of this section. These pumps deliver water to a well water storage tank of 50,000 gallon capacity. Two 100 percent capacity raw pumps supply water for the following uses:

- Makeup water to the service water system cooling tower
- Boiler treated makeup water
- Treated drinking water
- Pump seals
- Miscellaneous uses

The well water storage tank also serves as the reservoir which to supplies water to the fire protection water pumps in case of emergency.

The boiler makeup water treatment plant consists of two 100 percent capacity demineralizer trains, each rated at 15 gpm flow. Each demineralizer train consists of a feed pump, a carbon filler, a cation unit, an anion unit, and a mixed bed unit. Demineralized water is stored in a demineralized water storage tank of 10,000 gallon capacity. Two 100 percent capacity demineralized water pumps supply makeup water to the condenser. The demineralizers are periodically backwashed and regenerated with sulfuric acid and sodium hydroxide. These chemicals are stored in 2,000 gallon capacity tanks at the site. A neutralization tank with sump pumps is provided to neutralize demineralizer waste effluents from the plant.

The plant service water system consists of a small cooling tower, two 100 percent capacity service water pumps, basket strainers, piping and valves. See Figure 5-6. The service water system supplies cooling water to the following:

- Generator air coolers
- Turbine lube oil coolers
- Boiler feed pump lube oil and seal water coolers

- Vacuum pump condenser
- Gland steam condenser
- Induced draft fan lube oil cooler
- Primary air fan lube oil cooler
- Secondary air fan lube oil cooler
- Ash screw coolers
- Sample coolers

Service water is used for wetting ash and to minimize dust during ash handling. All system water losses are made up by the raw water system.

The main liquid wastes from the plant are fuel and ash handling area runoff, makeup demineralizer regeneration wastes and cooling tower blowdown. Fuel and ash handling area wastes can be collected and routed to a pond for settling and neutralization. Makeup demineralizer regeneration wastes are routed to a neutralization sump for pH control. Cooling tower blowdown requires no treatment circulating water pH is maintained between 8 and 9 during normal system operation. Waste water can be used for wetting ash and therefore very little plant waste water discharge to the local streams is expected.

5.4.9 Electrical Power System

The electrical power system generates and delivers electrical power to the high voltage transmission system via main step-up transformer. It also distributes all required electrical power to the plant auxiliaries. The system is shown in Figure 5-10 at the end of this section.

Power Generation and Transmission. Power is generated by a generator, rated 11 KV, 3 0, 50 Hertz. Power is delivered to the high voltage transmission system through a main step-up transformer, rated 11-132KV. The generator is protected by a generator breaker, rated 2,000 A, 500 MVA, operated normally closed. When the unit is started up, this generator breaker is opened and power to the plant auxiliaries is supplied from the high-voltage transmission system through the main step-up transformer. The system is provided with sensitive protective relaying system, instrumentation and control.

Power Distribution System. The power distribution system provides reliable power to all plant auxiliaries through an auxiliary transformer, rated 11-6.6 KV. Power is distributed at several voltage levels as follows:

- The 6.6 KV Medium Voltage System supplies power to large (above 250 HP) motors and the load center (LC) transformers
- The 380 V Low Voltage System supplies power to small motors (below 250 HP) and miscellaneous electric loads. Motors rated 75-200 HP are connected to load centers and motors rated less than 75 HP are connected to motor control centers (MCCs). The MCC also distributes power to lighting and power panels.
- The DC Distribution System supplies power to small DC motors and DC control circuits.
- The Vital AC System provides uninterruptible power for vital control, monitoring, and shutdown circuits.
- The Instrument AC System supplies power to instrumentation, control, and communication circuits.
- Miscellaneous Support Systems include the grounding, lighting, cathodic protection, raceway, and wiring systems.
- A small capacity service transformer provides power to selected vital auxiliary loads when the generator and high voltage off-site power supply are out of service.

5.4.10 Plant Control System

A central control room is utilized for major plant control functions and for plant monitoring. Local instrument and control panels for the boiler are provided to enable local startup of the boiler and auxiliaries. Electronic instruments will be powered by an uninterruptible power supply at 115 V ac, single phase. Positioners, actuators, etc. will be powered by dry, clean oil free instrument air.

5.4.11 Plant General Arrangement Drawings

The power plant location is shown on Figure 4-1. The highway and the transmissions lines are to the west of the power plant. The mine is to the east. The mining operation is responsible to mine oil shale crush, size and deliver to the storage silos at the power plant.

Equipment layout within the power plant area is shown on Figure 5.7. This drawing shows the relative locations of turbine, generator, air cooled condenser, boiler baghouse, stack, inplant fuel storage silo, auxiliary bay, etc. Figure 5-8 at the end of this section shows views of boiler and turbine houses.

5.4.12 Power Plant On-site Infrastructure

The power plant includes an adminstrative and warehouse building. A small machine shop, electrical shop and instrument shop are required. A laboratory to analyze fuel and water is also required. On onsite first-aid facility and personnel changeout facility, bath, and lavatory facilities are also needed.

The capital cost of the on-site infrastructures also includes roads, fencing, gates, yard lighting and telecommunication, yard drainage and sewerage, and secutiy systems etc. Fuel, chemical, waste and by-product storage and handling systems are not included in on-site infrastructure cost.

The on-site infrastructures cost is included in total power plant capital cost as described in Section 5.6.1.

5.5 OFF-SITE INFRASTRUCTURE

For this study an allowance was made for inclusion of off-site infrastructures. The off-site infrastructures include housing and community facilities for the integrated project employees and families. The estimated project staffing includes:

o	Mining and shale processing	75
o	Power Block	100
o	Project Management	10
	TOTAL STAFF	185

The cost of these community facilities is provided for as an allowance in developing the integrated project capital cost described in Section 5.6.1.

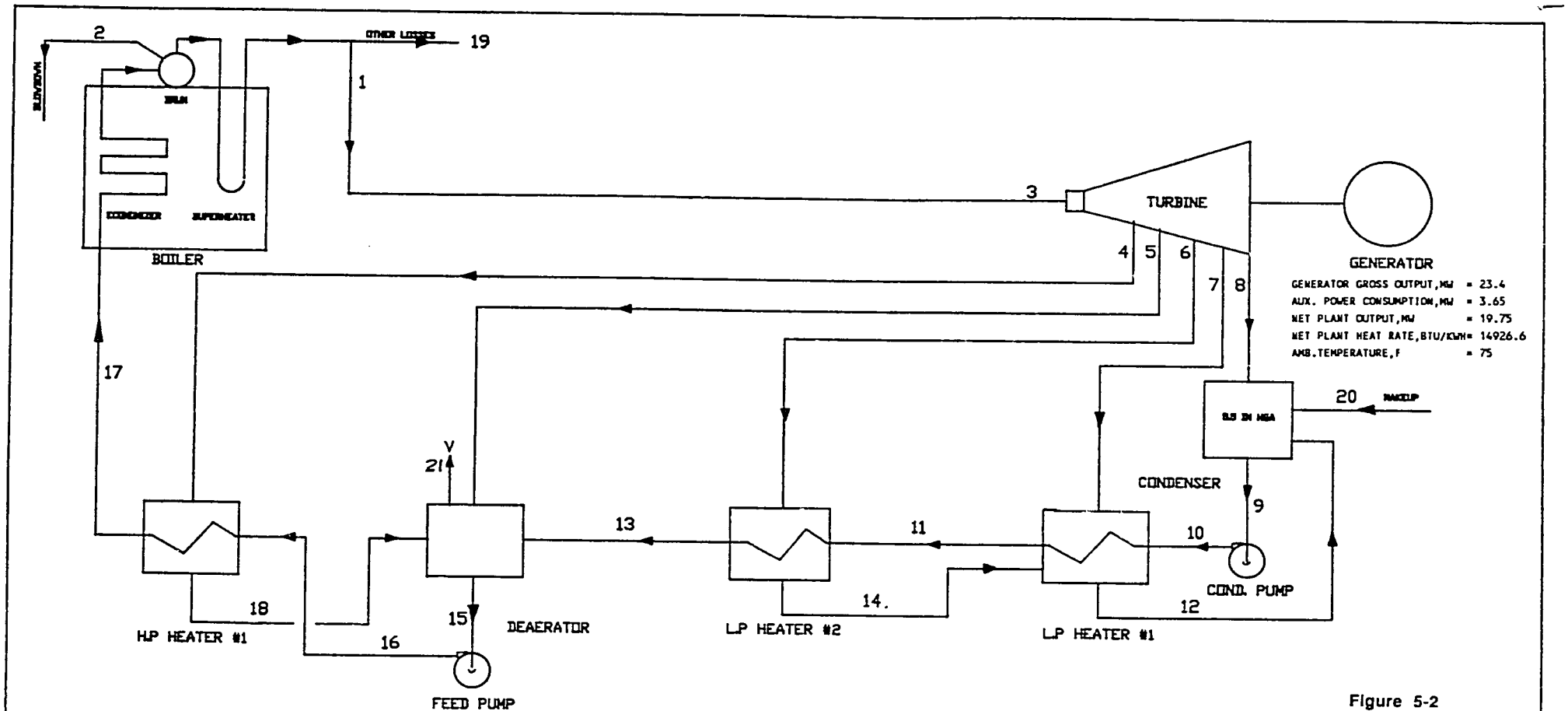


Figure 5-2

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PRESSURE,PSIA	1563.5	1728.5	1463.5	182.5	74	27	5.7	2.7	2.7	124.3	110.3	5.4	95.3	25.7	70.3
TEMPERATURE,F	955	615.4	950	492.6	338.4	244.4	167.8	137.4	132.7	132.7	160.6	142.4	236.5	170.6	303.2
ENTHALPY,BTU/LB.	1460.8	639.9	1461.3	1266.9	1199	1134.1	1047.3	1010	100.6	100.7	128.8	110.3	205.1	138.7	273
FLOW,LB/HR	200000	2000	200000	13276.7	13045	13512	4905	155261.3	176478	176478	176478	18417	176478	13512	202500

STREAM NO.	16	17	18	19	20	21
PRESSURE,PSIA	1788.5	1773.5	173.4	1563.5	30	70.3
TEMPERATURE,F	306.9	370	316.9	955	60	303.2
ENTHALPY,BTU/LB.	280	345.2	287.3	1460.8	28.1	1180.6
FLOW,LB/HR.	202500	202500	13276.8	500	2800	300

BOILER HEAT INPUT,MMBTU/HR.	= 294.8
BOILER LOSSES,MMBTU/HR	= 70.5
CONDENSER DUTY,MMBTU/HR.	= 141.2
GROSS POWER,MMBTU/HR.	= 79.9
OTHER STEAM CYCLE LOSSES,MMBTU/HR.	= 3.2

BECHTEL
SAN FRANCISCO

JORDAN OIL SHALE TO POWER PROJECT

STEAM CYCLE DIAGRAM
20 MW UNIT

JOB NO. 17908-005 | DRAWING NO. M001 | REV. 0

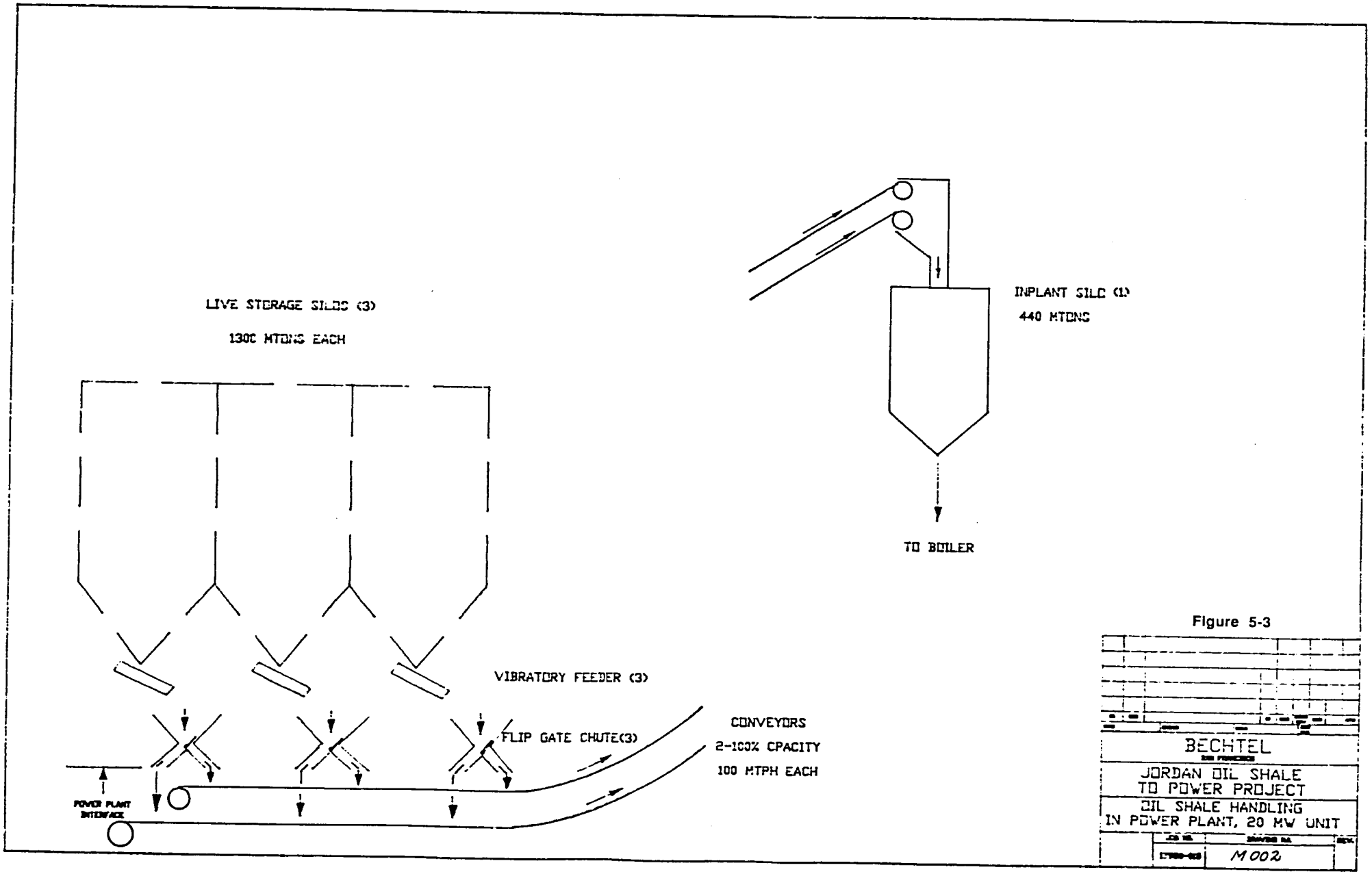
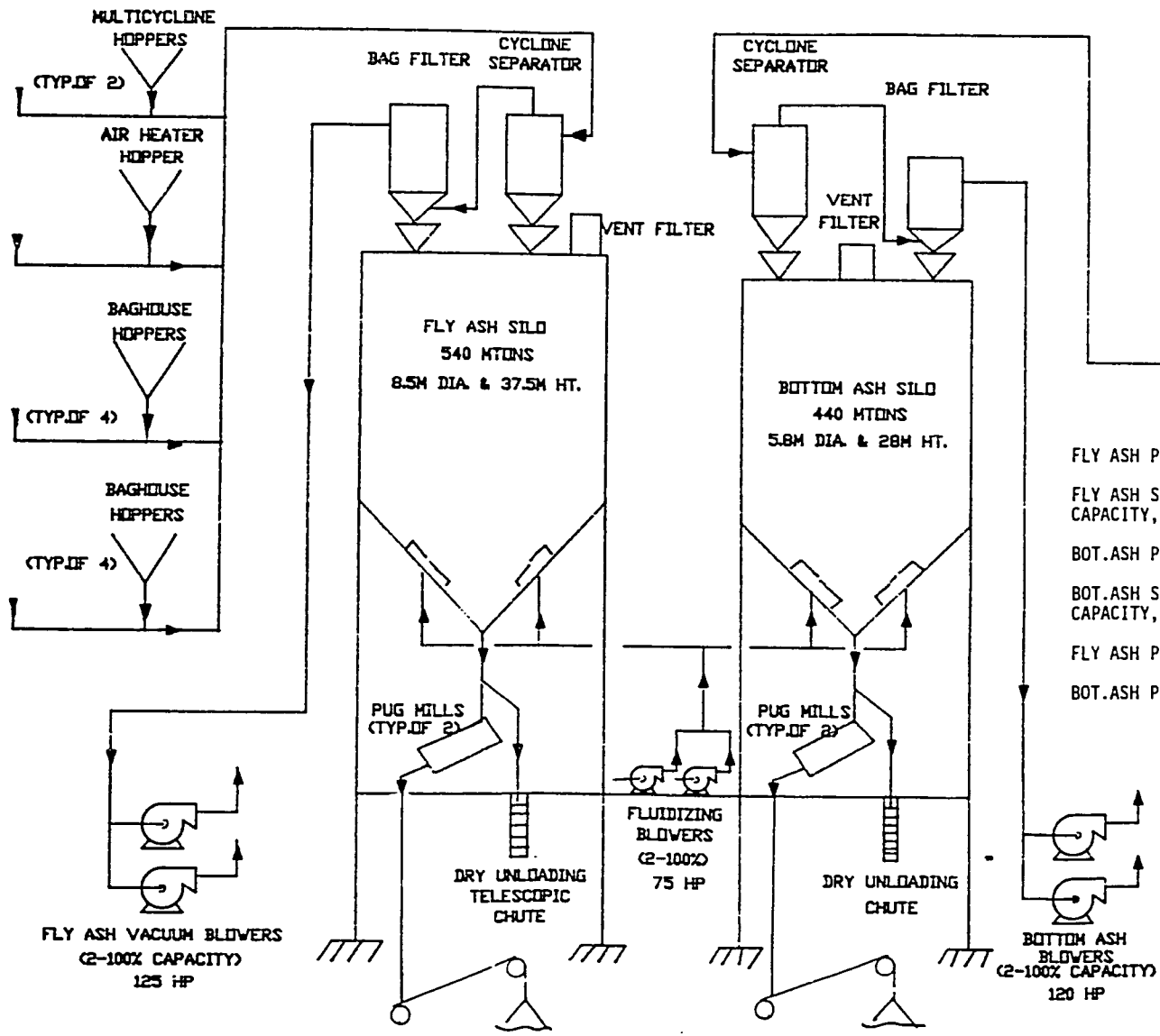

LIVE STORAGE SILOS (3)
1300 MTONS EACH
INPLANT SILO (1)
440 MTONS
TO BOILER
VIBRATORY FEEDER (3)
FLIP GATE CHUTE(3)
CONVEYORS
2-100% CPACITY
100 MTPH EACH
POWER PLANT INTERFACE
BECHTEL
JORDAN OIL SHALE
TO POWER PROJECT
OIL SHALE HANDLING
IN POWER PLANT, 20 MW UNIT
M002

Figure 5-3



FLY ASH PRODUCTION RATE, TONNES/HR	= 22.2
FLY ASH SYSTEM DESIGN CAPACITY, TONNES/HR	= 44.5
BOT.ASH PRODUCTION RATE, TONNES/HR	= 18.2
BOT.ASH SYSTEM DESIGN CAPACITY, TONNES/HR	= 36.5
FLY ASH PUG MILL CAPACITY, TONNES/HR	= 75
BOT.ASH PUG MILL CAPACITY, TONNES/HR	= 60

Figure 5-4

BECHTEL

JORDAN OIL SHALE TO POWER PROJECT

ASH HANDLING SYSTEM 20 MW UNIT

M003

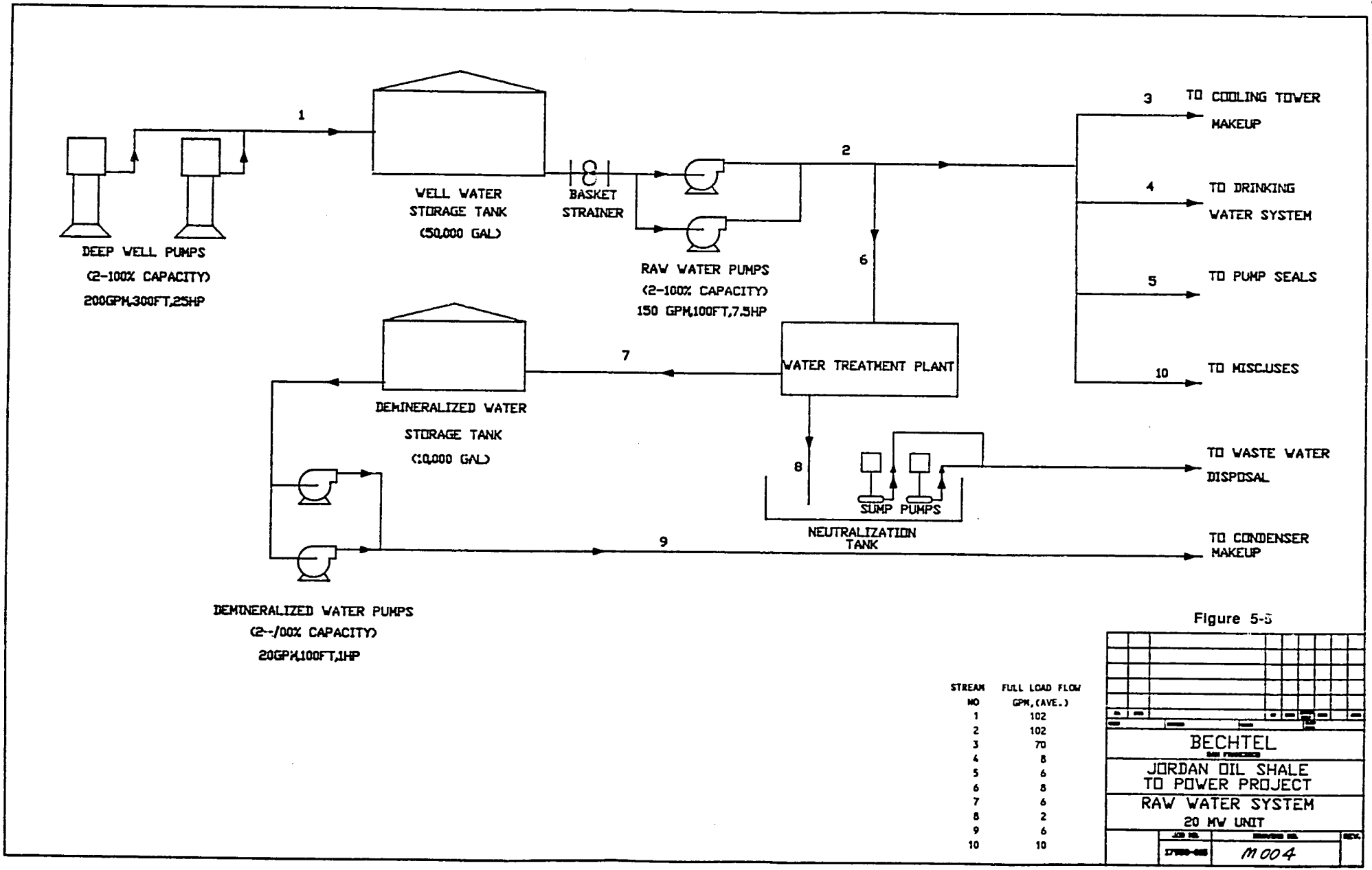


Figure 5-5

STREAM NO	FULL LOAD FLOW GPM, (AVE.)
1	102
2	102
3	70
4	8
5	6
6	8
7	6
8	2
9	6
10	10

BECHTEL
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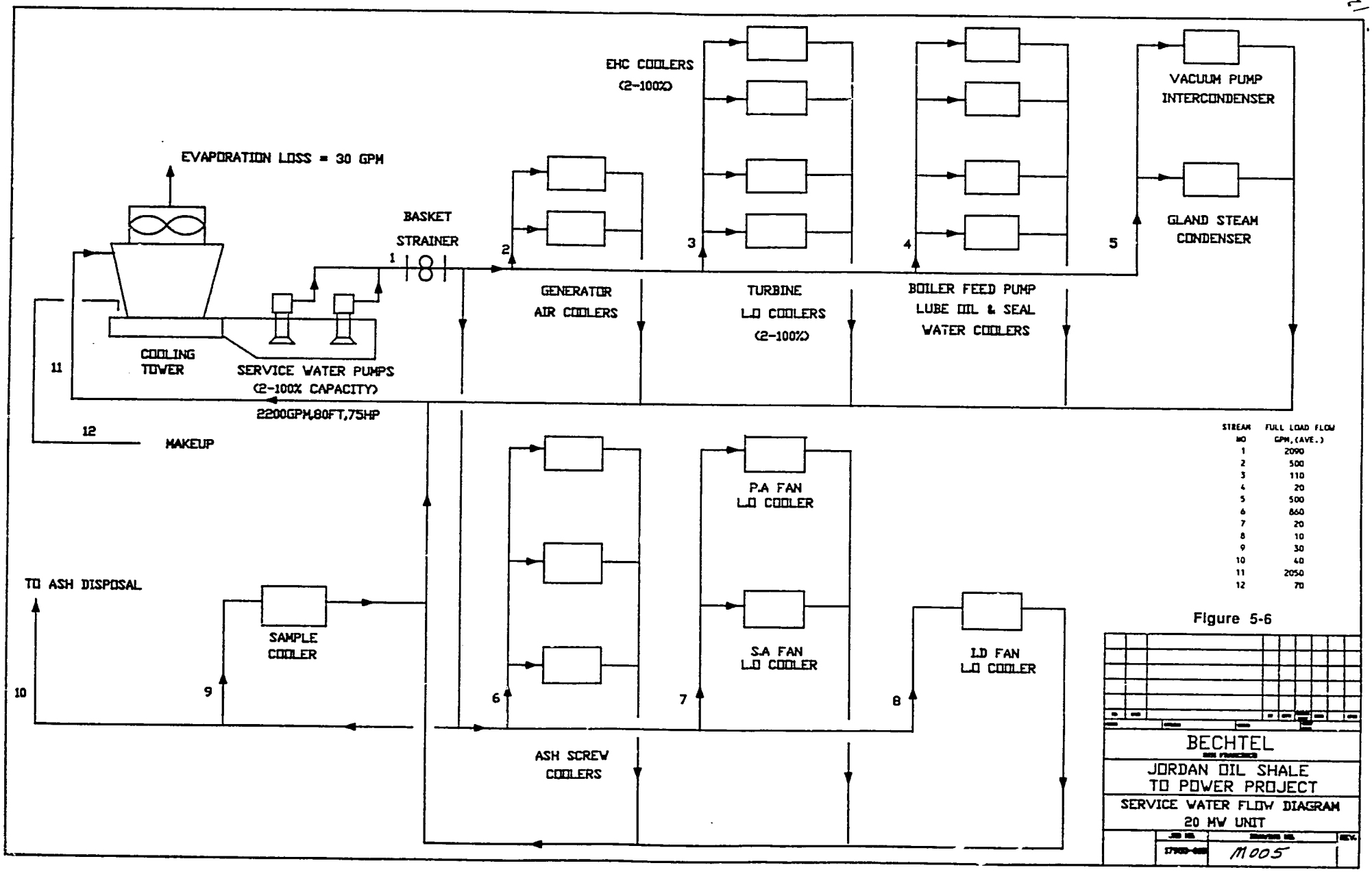
JORDAN OIL SHALE
TO POWER PROJECT

RAW WATER SYSTEM
20 MW UNIT

JOB NO. 17700-005 | DRAWING NO. M004 | REV.



STREAM NO	FULL LOAD FLOW GPM, (AVE.)
1	2090
2	500
3	110
4	20
5	500
6	860
7	20
8	10
9	30
10	40
11	2050
12	70

Figure 5-6

BECHTEL
SAN FRANCISCO

JORDAN OIL SHALE TO POWER PROJECT

SERVICE WATER FLOW DIAGRAM 20 MW UNIT

M005

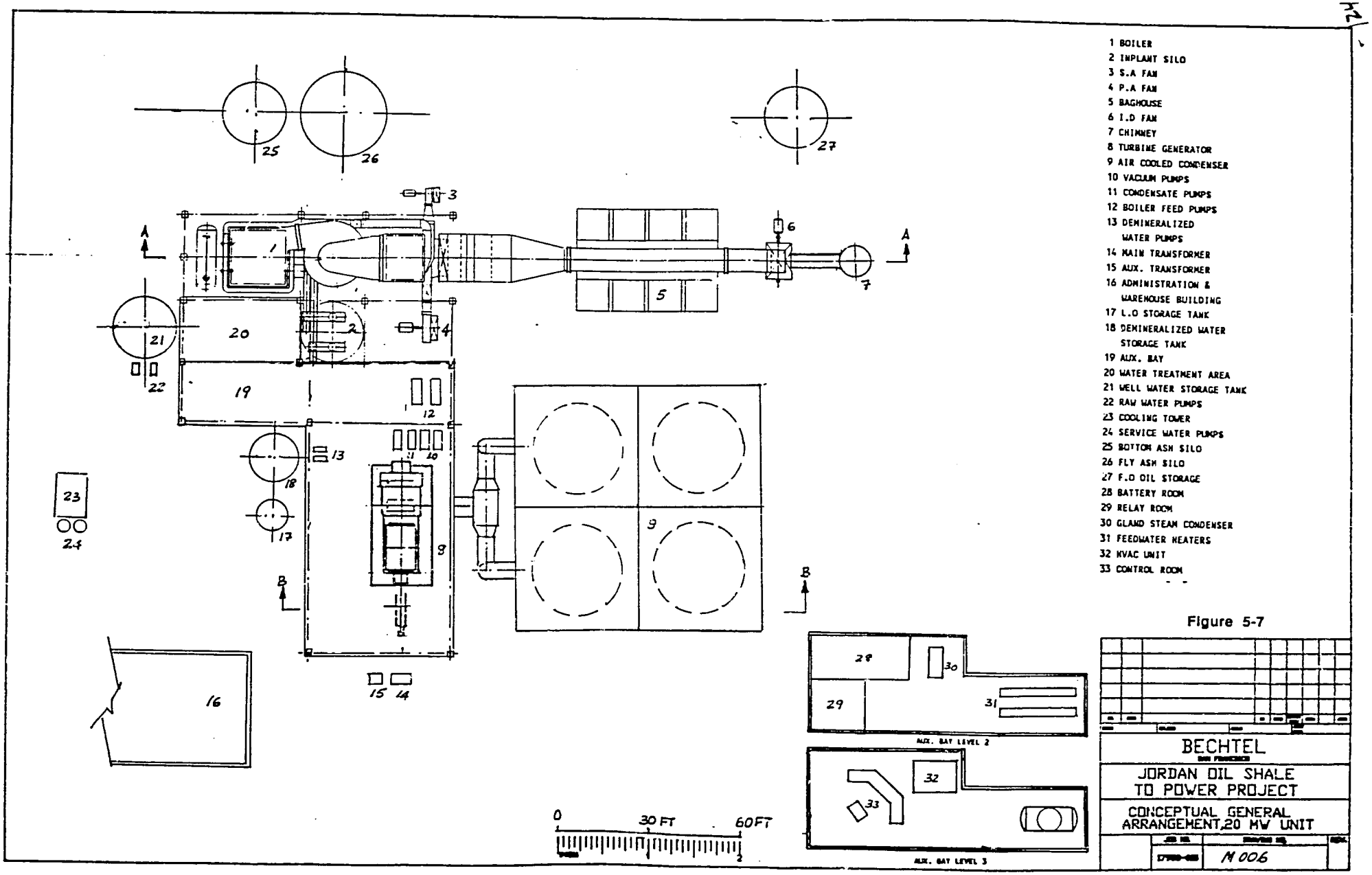
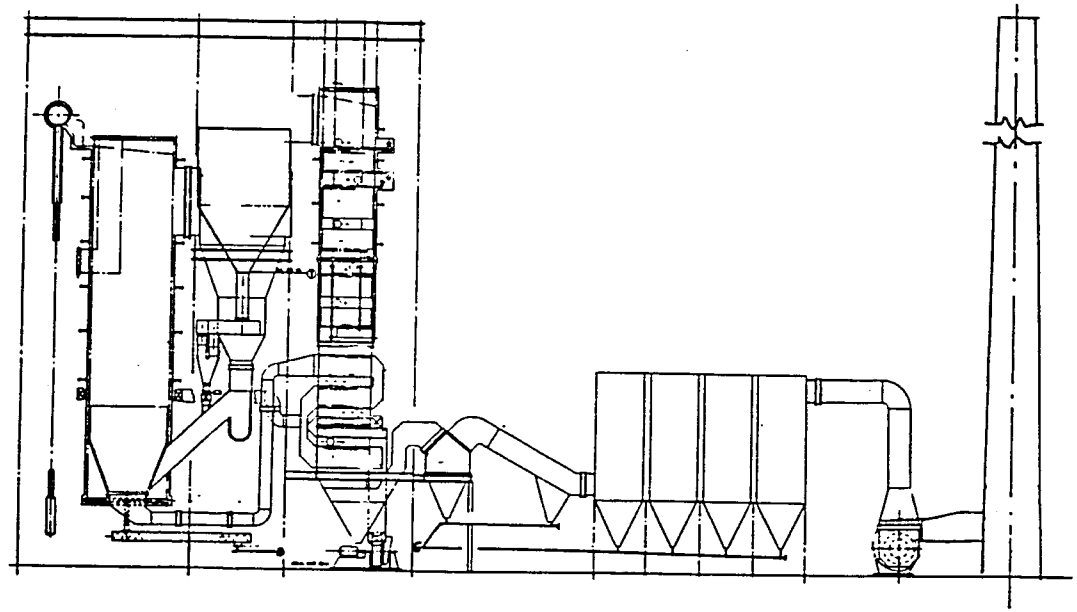
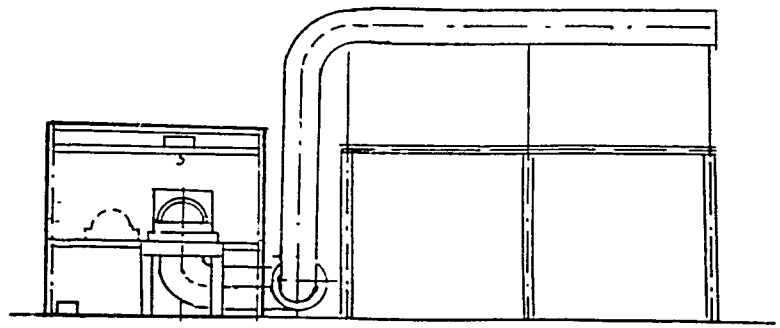

1 BOILER
2 INPLANT SILO
3 S.A FAN
4 P.A FAN
5 BAGHOUSE
6 I.D FAN
7 CHIMNEY
8 TURBINE GENERATOR
9 AIR COOLED CONDENSER
10 VACUUM PUMPS
11 CONDENSATE PUMPS
12 BOILER FEED PUMPS
13 DEMINERALIZED WATER PUMPS
14 MAIN TRANSFORMER
15 AUX. TRANSFORMER
16 ADMINISTRATION & WAREHOUSE BUILDING
17 L.O STORAGE TANK
18 DEMINERALIZED WATER STORAGE TANK
19 AUX. BAY
20 WATER TREATMENT AREA
21 WELL WATER STORAGE TANK
22 RAW WATER PUMPS
23 COOLING TOWER
24 SERVICE WATER PUMPS
25 BOTTOM ASH SILO
26 FLY ASH SILO
27 F.O OIL STORAGE
28 BATTERY ROOM
29 RELAY ROOM
30 GLAND STEAM CONDENSER
31 FEEDWATER HEATERS
32 HVAC UNIT
33 CONTROL ROOM
0
30 FT
60FT
AUX. BAY LEVEL 2
AUX. BAY LEVEL 3
BECHTEL
JORDAN OIL SHALE TO POWER PROJECT
CONCEPTUAL GENERAL ARRANGEMENT,20 MW UNIT
M 006

Figure 5-7



VIEW AA



VIEW BB

Figure 5-8

BECHTEL

JORDAN OIL SHALE
TO POWER PROJECT

CONCEPTUAL GENERAL
ARRANGEMENT,20 MW UNIT

M007

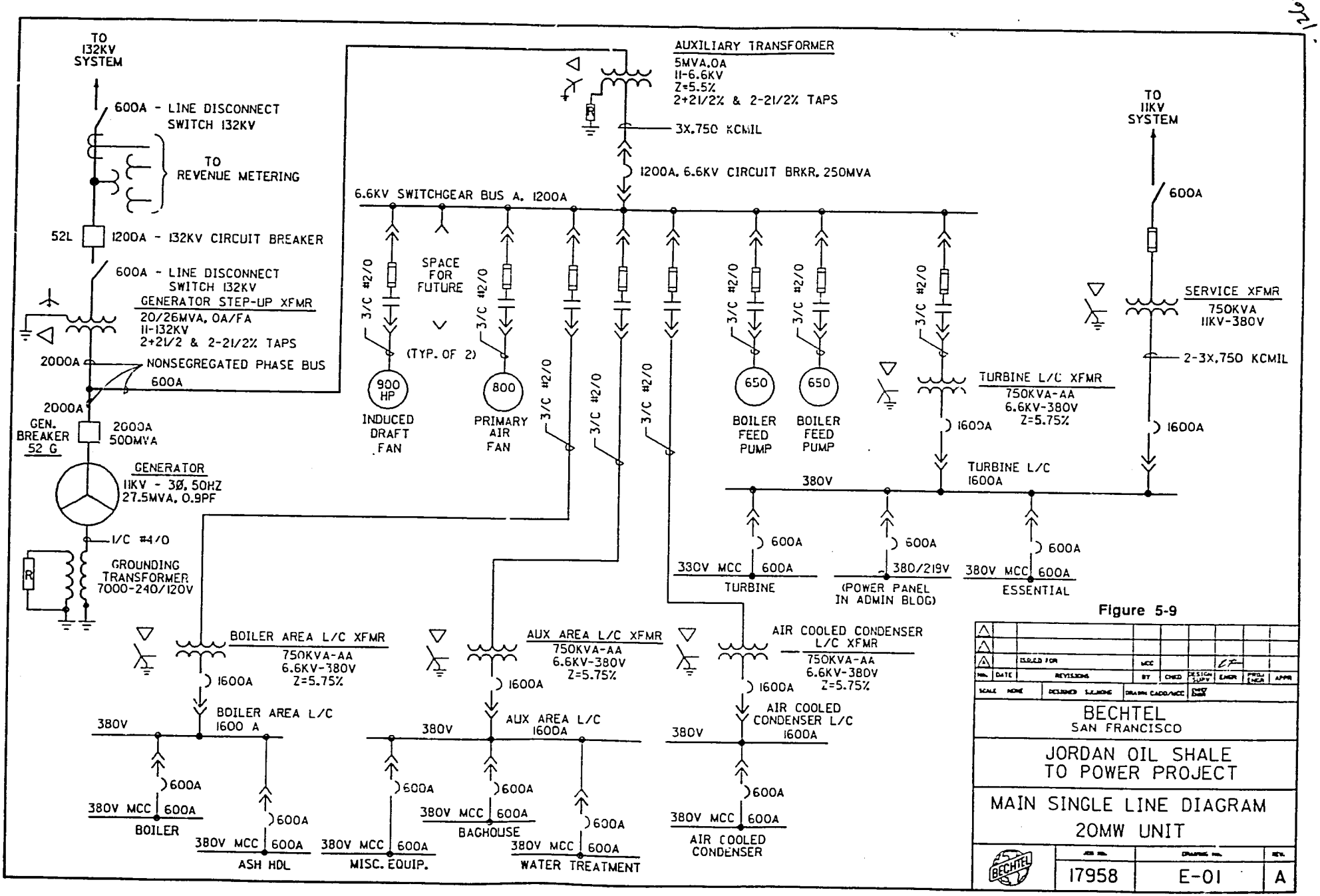

TO 132KV SYSTEM
600A - LINE DISCONNECT SWITCH 132KV
TO REVENUE METERING
52L
1200A - 132KV CIRCUIT BREAKER
600A - LINE DISCONNECT SWITCH 132KV
GENERATOR STEP-UP XFMR
20/26MVA, OA/FA
11-132KV
2+21/2 & 2-21/2% TAPS
2000A
NONSEGREGATED PHASE BUS
600A
2000A
GEN. BREAKER 52 G
2000A 500MVA
GENERATOR
11KV - 3Ø, 50HZ
27.5MVA, 0.9PF
1/C #4/0
GROUNDING TRANSFORMER 7000-240/120V
AUXILIARY TRANSFORMER
5MVA,OA
11-6.6KV
Z=5.5%
2+21/2% & 2-21/2% TAPS
3X.750 KCMIL
1200A, 6.6KV CIRCUIT BRKR, 250MVA
6.6KV SWITCHGEAR BUS A, 1200A
3/C #2/0
SPACE FOR FUTURE
(TYP. OF 2)
900 HP
INDUCED DRAFT FAN
800
PRIMARY AIR FAN
650
BOILER FEED PUMP
650
BOILER FEED PUMP
TURBINE L/C XFMR
750KVA-AA
6.6KV-380V
Z=5.75%
1600A
TURBINE L/C 1600A
TO 11KV SYSTEM
600A
SERVICE XFMR
750KVA
11KV-380V
2-3X.750 KCMIL
1600A
380V
600A
330V MCC 600A
TURBINE
380/219V
(POWER PANEL IN ADMIN BLDG)
380V MCC 600A
ESSENTIAL
BOILER AREA L/C XFMR
750KVA-AA
6.6KV-380V
Z=5.75%
1600A
BOILER AREA L/C 1600 A
380V
380V MCC 600A
BOILER
380V MCC 600A
ASH HDL
AUX AREA L/C XFMR
750KVA-AA
6.6KV-380V
Z=5.75%
1600A
AUX AREA L/C 1600A
380V
380V MCC 600A
MISC. EQUIP.
380V MCC 600A
BAGHOUSE
380V MCC 600A
WATER TREATMENT
AIR COOLED CONDENSER L/C XFMR
750KVA-AA
6.6KV-380V
Z=5.75%
1600A
AIR COOLED CONDENSER L/C 1600A
380V
380V MCC 600A
AIR COOLED CONDENSER
BECHTEL
SAN FRANCISCO
JORDAN OIL SHALE TO POWER PROJECT
MAIN SINGLE LINE DIAGRAM
20MW UNIT
17958
E-01
A

Figure 5-9

5.6 COST ESTIMATES

This section presents order of magnitude estimates of capital cost, first year operation and maintenance cost and 25 years levelized cost of electricity generating facility.

The cost estimates methodology, and the approach used to prepare them are described in Section 4.6.1.

5.6.1 Installed Power Block Capital Cost

Cost Estimate Methodology. See Section 4.61.

Cost Estimate Approach. See Section 4.6.1.

Capital Cost Estimate. The capital cost estimate for power plant is shown under Item (A) in Table 5-5. The capital cost has been developed in accordance with the scope and technical specifications described in Section 5.4. In developing these estimates the cost impact on major equipment purchased in the worldwide market and maximum use of locally available materials and labor has been assumed. This recognizes the indigenous craft skills developed on existing thermal power plants in Jordan. The capital cost for the 20 MW project is considered to have an accuracy of ±25 percent.

Cost Estimates Qualifications and Assumptions. See Section 4.6.1.

5.6.2 Cash Flow See Section 4.6.2.

5.6.3 Power Block Operating Requirements

Estimates cover first year operating costs for power plant only.

First year operating costs are presented in Table 5-6. All costs are at the mid-1988 price level.

Total first year opearating costs include fixed and variable operating and maintenance costs, and fuel (oil shale) costs. An explanation of each item follows.

Table 5-5

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
CONCEPTUAL INTEGRATED 20 MW DEMONSTRATION PLANT
SUMMARY OF COSTS
($ in 1,000 Mid-1988 Price Level)

		COST $
A)	POWER PLANT:	
	Inplant Fuel Handling	$ 800
	Steam Generator + Stack + Baghouse	29,400[a]
	Turbine, Cond, F/Wtr, Etc.	10,000
	Ash Handling	1,000
	General Facilities:	
	Tankage	300
	Cooling System	1,300
	Fire Protection	800
	Waste Water	300
	Electrical	2,300
	Control/Instrumentation	1,300
	Site Improvement	900
	Miscellaneous	1,900
	Building:	
	Turbine	500
	Boiler Foundation and Structure	2,900
	Auxiliary/Control	700
	Water Treatment	100
	Admin/Warehouse	700
	Yard Facility	200
	Services Building	600
	Switch Yard:	900
	Sub Total Plant Cost:	$ 57,500
	Owner's Cost/Working Allowance for Funds During Construction:	$ 7,300
	Other's Allow (see 4.6.1):	$ 2,900
	Sub Total Owner's Capital Costs:	$ 10,200
	TOTAL POWER PLANT COSTS:	$ 67,700
B)	ALLOWANCE FOR OFF-SITE INFRASTRUCTURE:	$ 10,700
C)	MINING & SHALE PROCESSING COSTS (Table 5-1):	$ 27,869
D)	ASH & OVERBURDEN WASTE DISPOSAL (Table 5-2):	$ 1,618
	TOTAL INSTALLED PROJECT CAPITAL COSTS (50/50 Debt/Equity):	$107,287
	TOTAL INSTALLED PROJECT CAPITAL COSTS (80/20 Debt/Equity):	$108,753

(a) Includes $16,500,000 for boiler cost from Pyropower adjusted for Jordan location.

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Table 5-6

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
20 MW CONCEPTUAL DEMONSTRATION PLANT
OPERATING REQUIREMENTS - 1ST YEAR

A. DEBT / EQUITY RATIO :========== 50/50

NET GENERATION -	MWe	20.50
CAPACITY FACTOR -	%	75%
ANNUAL GENERATION	MKWh/YR	135
SUB TOTAL PLANT COSTS (TPC)		$57,500

FIXED O & M COSTS:	MH	$ /MH	FIRST YEAR COST$1,000
OPERATING LABOR :	134,784	$3	$400
MAINTENANCE LABOR :			
@ 40.00% of	1.50%	OF TPC	345
MAINTENANCE MATERIAL :			
@ 60.00% of	1.50%	OF TPC	518
ADMIN LABOR :	30.00%	OF O & M LABOR	224
SUB TOTAL FIXED O&M COSTS:			$1,487

VARIABLE O & M COSTS:	QUANTITY	UNIT COST	
VARIABLE MAINTENANCE	135 MKWh	1 MILL/KWH	$135
PROCESS WATER	675,000 GALLON	$0.2/GAL	$135
GENERAL PLANT CHEMICALS		ALLOW	50
FUEL OIL	50,000 GALLON	$0.35/GAL	$18
WASTE DISPOSAL (Section 4.2.7)	327,000 TN/YR	$1.20 $/TN	$392
SPECIAL BOILER MAINT		ALLOW	200
SUB TOTAL VARIABLE O&M COSTS:			$930
TOTAL FIXED & VARIABLE O&M COSTS:			$2,417
OIL SHALE FUEL (Section 4.2.5)	390,000 TN/YR	$17.50 $/TN	$6,825

B. DEBT / EQUITY RATIO :========== 80/20

TOTAL FIXED & VARIABLE O&M COSTS (W/O ASH DISPOSAL)			$2,205
WASTE DISPOSAL (Section 4.2.7)	327,000 TN/YR	$0.97 $/TN	$317
TOTAL FIXED & VARIABLE O&M COSTS :			$2,342
OIL SHALE FUEL (Section 4.2.5)	390,000 TN/YR	$14.31 $/TN	$5,581

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Fixed O&M Costs. Fixed O&M costs include both operating labor and maintenance labor plus materials to operate the power plant. The average labor rate employed, corresponding to a direct labor charge plus payroll additives, is $3.00/hr. The staffing requirement for power plant operation is presented in Table 5-7.

Annual maintenance costs are estimated as a percentage of the total power plant cost (TPC). The percentage varies widely depending on the nature of the processing conditions and type of power plant. The rate of 1.50 percent was selected for this facility.

Maintenance labor is typically 40 percent and maintenance material 60 percent of the toal maintenance cost. Administrative and support labor is assumed to be 30 percent of the operating and maintenance labor.

Variable O&M Costs. Variable O&M costs include the following:

- Variable maintenance costs in addition to the fixed maintenance costs are estimated to be 1 mill per kilowatt hour of operation.
- Utility costs of process water are $0.20 per one thousand gallons. Stean and electricity for plant use are not included as directed costs, but rather impact the plant heat rate.
- General plant chemical costs are estimated as an allowance.
- Disposal of ash by truck haul to a dedicated waste disposal area including loading costs at the power plant, hauling, dumping, spreading,is estimated to cost:

  a) At debt/equity 50/50 - $1.20/ton

  b) At debt/equity 80/20 - $0.97/ton

Fuel Costs. Fuel (oil shale) costs are an additional variable operating cost. The oil shale costs are as follows:

a) At debt/equity 50/50 - $17.50/ton

b) At debt/equity 80/20 - $14.31/ton

Table 5-7

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY

20 MW CONCEPTUAL DEMONSTRATION PLANT
POWER BLOCK
OPERATION & MAINTENANCE STAFFS

JOB DESCRIPTION	WEEK DAY	WEEK END	SWING	NIGHT	TOTAL
OPERATION					
SUPERINTENDENT	1				1
SHIFT FOREMAN	1	1	1	1	4
FUEL SUPPLY SUPERVISOR	1				1
TECHNICAL SUPERVISOR	1				1
CONTROL ROOM OPERATOR	1	1	1	1	4
CONTROL ROOM TECHNICIAN	1	1	1	1	4
PLANT CHEMIST	1				1
LAB TECHNICIAN	2				2
BOILER OPERATOR	2	2	2	2	8
MISC. OPERATOR	2	2	2	2	8
FUEL MAN	1	1	1	1	4
HELPER OPERATOR	2	2	2	2	8
ENGINEER	2	2	2	2	8
TOTAL OPERATORS	18	12	12	12	54

TOTAL OPERATOR/SHIFT (AVERAGE) 15 MAN/SHIFT

TOTAL MAINTENANCE STAFFS/SHIFT 13 MAN/SHIFT

TOTAL C&M PER SHIFT 28 MAN SHIFT

Staffing Required	
Operations	54
Maintenance	46
TOTAL	100

5.6.4 Busbar Cost of Electricity

Employing the previously developed costs, an estimate of electricity is presented in Table 5-8 for the first year of operation. Levelized costs for future years operations were not created because it is visualized that this project is a demonstration operation only.

It should be noted that a 15 percent capital charge used for the power block facilities is typical of the capital charge rate for many USA utility installations. It is the equivalent of a 9 percent interest rate on the borrowed capital component plus a 13.5 percent return on the equity component, plus depreciation, insurance and tax charges for the various equipment categories and facilities involved (Section 6.9). Using EPRI procedures for calculation of fixed charge rates on capital for the two debt/equity ratios selected for the analysis we developed the following rates:

Debit/Equity Ratio	Capital Charge Rate
50/50	15.3
80/20	13.9

The oil shale fuel cost was computed using fixed capital rates of 10 percent interest on borrowed capital component plus a 20 percent return on the equity component. This is more typical of mining venture capital charges.

The off-site infrastructure investment was assumed to be self liquidating and is not included in the Busbar rate calculations.

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Table 5-8

BREAKDOWN AND SENSITIVITY OF POWER COSTS TO CAPITAL AND OPERATING COST COMPONENTS

20 MW CONCEPTUAL DEMONSTRATION PLANT

DEBT/EQUITY RATIO : 50/50	1ST YEAR	
	$1,000	MILLS/KWH
Capital Charges @ 15.3% (Power Block)	$10,358	77
Operation & Maintenance	2,417	18
Fuel - Oil Shale	6,825	51
Total Busbar Cost:	$19,600	146

DEBT/EQUITY RATIO : 80/20	1ST YEAR	
	$1,000	MILLS/KWH
Capital Charges @ 13.9% (Power Block)	$ 9,410	70
Operation & Maintenance	2,342	17
Fuel - Oil Shale	5,581	41
Total Busbar Cost:	$17,333	128

NOTE:

- Capital charges include Power Plant only.
- Fuel - Oil shale includes capital charges for Mining & Material Handling Plant.

Section 6
400 MW Commercial Scale Integrated Project

Section 6

400 MW COMMERCIAL SCALE INTEGRATED PROJECT

6.1 INTRODUCTION

The original approved Work Scope for this Prefeasibility Study included preparation of conceptual designs and costs for a 4x100 MW Commercial Scale Project.

It was visualized that immediately following completion of a short operating period on the Demonstration Project (either 20 or 50 MW size), design and construction of the Commercial Scale Project would commence. The latter would comprise construction of four 100 MW boilers, each commencing about one year after its predessor. Because of budget limitations it was agreed at the April 1988 Amman program review that the power block facilities would be handled as a "factored" estimate. A separate Mine and Materials Handling Plan has been created for this case study, which was included with original 1987 scope of work. No adjustments were made to the program budget for this design which had been completed by the April 1988 change of scope.

The following subsections describe the conceptual plans and costs involved with the Integrated 400 MW Project.

6.2 MINE AND MATERIALS HANDLING PLAN

The large volume of overburden to be removed as well as the large amount of oil shale to be mined and processed for the 400 MW plant requires a more efficient and reliable operation than that for the 20 MW and 50 MW plants. Instead of attempting to factor costs from the 50 MW plant study, new mining and shale processing concepts were prepared in order to arrive at a more realistic cost of the fuel entering the boiler in the 400 MW case.

6.2.1 Mine Development Plan

The northern area of the deposit was selected for the large scale mine because of the shallower overburden (35 metres) which facilitates the development of the mine.

The development would begin along the west flank where an incline and box-cut would be excavated simultaneously in a northwesterly direction. The incline will be driven on an 8 percent grade and 30 metres wide to accommodate the oil shale belt conveyor and two-way truck traffic. The box-cut will be located immediately north of the incline ramp and it will expose an area on top of the oil shale that is 1,000 metres long and 80 metres wide. The box-cut will be comprised of four benches in the overburden and two in the oil shale. These benches will be 10 metres or less in height and 49 metres wide located in the advancing face on the east side. The oil shale benches will be mined as far as is necessary to provide space at the base of the incline for the construction of the oil shale truck dump hoppers and conveyor belt. Along the west side and north end of the box-cut, off-sets in the excavation will be made at the lower and intermediate level to allow for two-way truck traffic for the back-fill operation of the pit. A haulroad for the 136 tonne trucks will be constructed between the top of the incline and the out-of-pit wastepile.

In addition to the development excavation there will be facilities constructed for the handling of the oil shale, i.e., transporting it out of the pit and storing it before delivery is made to the processing plant. At the base of the incline ramp, two truck dump hoppers each with a capacity of 300 tonnes will receive oil shale from the 136 tonne trucks. The oil shale will be mined by surface miners, which mine a product less than 200 mm in size, and therefore a primary cursher is not required. Each of the hoppers is equipped with a variable speed feeder and they feed onto a 1,500 mm wide belt conveyor for delivery of the oil shale to the surface processing plant. The belt is designed for 3,000 tonnes per hour to handle surges without spillage but the normal rate of conveying is 2,000 tonnes per hour. As the oil shale reaches the surface it is transferred to a conveyor that elevates the oil shale to a three-stage sampler for collecting representative samples.

After the oil shale passes through the sampler, it is deposited onto a traveling stacker which places the oil shale in storage. The storage consists of two concrete basins, constructed 'V'-shaped hopper bottoms with an integral plow feeder shelf along its length. Each storage basin is 200 metres long and will store 100,000 tonnes. Each storage is equipped with two variable speed rotary plow feeders and the reclaim system is designed for 3,000 tonnes per hour.

6.2.2 Mine Operation

The basic mining activities include top-soil removal and storage, drilling blasting, loading and hauling overburden to out-of-pit waste pile or back-filling the pit, and mining, hauling and conveying oil shale to the surface oil shale storage. The mine is scheduled to operate 900 shifts per year and the average annual production is 7.78 million tonnes. The designed mining rate is 2,000 tonnes per hour of oil shale that meets Pyropower performance fuel specification for the boiler plant when it is operating at 100 percent capacity factor. The overburden mining rate will be 10 million cubic metres per year.

Major equipment selected for this operation are three blast hole drillers capable of drilling 250 mm diameter holes, three electric power shovels with dipper capacity of 20 cubic metres, twenty haul trucks with a carrying payload of 136 tonnes and two surface miners each capable of mining oil shale at the rate of 2,000 tonnes per hour.

As the mine moves from the development stage to the production stage, the bench heights will be increased to 15 metres. Each bench in the overburden will be equipped with a blast hole drill, an electric power shovel and the required number of trucks. As the overburden increases in thickness these pieces of equipment will be moved accordingly to maintain the advancing face. Two front end loaders are included in the equipment list to serve as back-up to a shovel or to supplement the production. In advancing the pit from the box-cut towards the east, a series of cuts measuring 80 metres wide by two or three kilometers long will be excavated. Backfilling of the pit should start after the end of second year of operation.

Because of the vertical and lateral variation in the oil content of the oil shale and the need for a consistent grade of fuel to the power plant, selective mining and elaborate blending of oil shales will be utilized. Selective mining will be accomplished by two surface miners. The machines will excavate the oil shale in plies of up to 610 mm thick by 4140 mm wide. The thickness of these plies can be varied between a minimum of 150 mm and a maximum of 610 mm with a cutting tolerance of 25 mm. This feature provides for the selectivity of separating high grade from low grade oil shales and for removing waste materials from the oil shale beds. The machine will cut the softer materials into minus 200 mm pieces. With the harder materials, the cutting rate is decreased which will yield a product of approximately minus 150 mm.

Oil shale will be loaded directly into the 136 tonne trucks and hauled to the in-pit truck dump hopper. Two dump hoppers are provided to prevent truck delays. The oil shale is fed onto the belt conveyor for conveying out of the pit. The oil shale is weighed over a belt scale and sampled before it is placed in storage by the traveling stacker. The traveling stacker can travel back and forth along the 200 metre storage laying down thin layers of oil shale with each pass or it can start at one end of the storage filling it as it travels to the other end. Adjustment to the oil shale mix is made with the variable speed drives of the rotary plow feeders used in reclaiming the oil shale from storage.

6.2.3 Oil Shale Processing

Oil shale processing facilities include three separate facilities each with a capacity of 1,000 tonnes per hour. Two circuits will be in operation at all times when the power plant is operating at 100 percent capacity factor and the third circuit will be on stand-by or out of service for maintenance.

Oil shale from the two storage facilities will be conveyed to a transfer tower at a rate of 3,000 tonnes per hour. At the transfer tower the oil shale is transferred onto either one of two conveyors that delivers the oil shale to either of three feed bins through a chute arrangement. See Figure 6-1 for details. From a feed bin a variable speed feeder feeds a large reversible

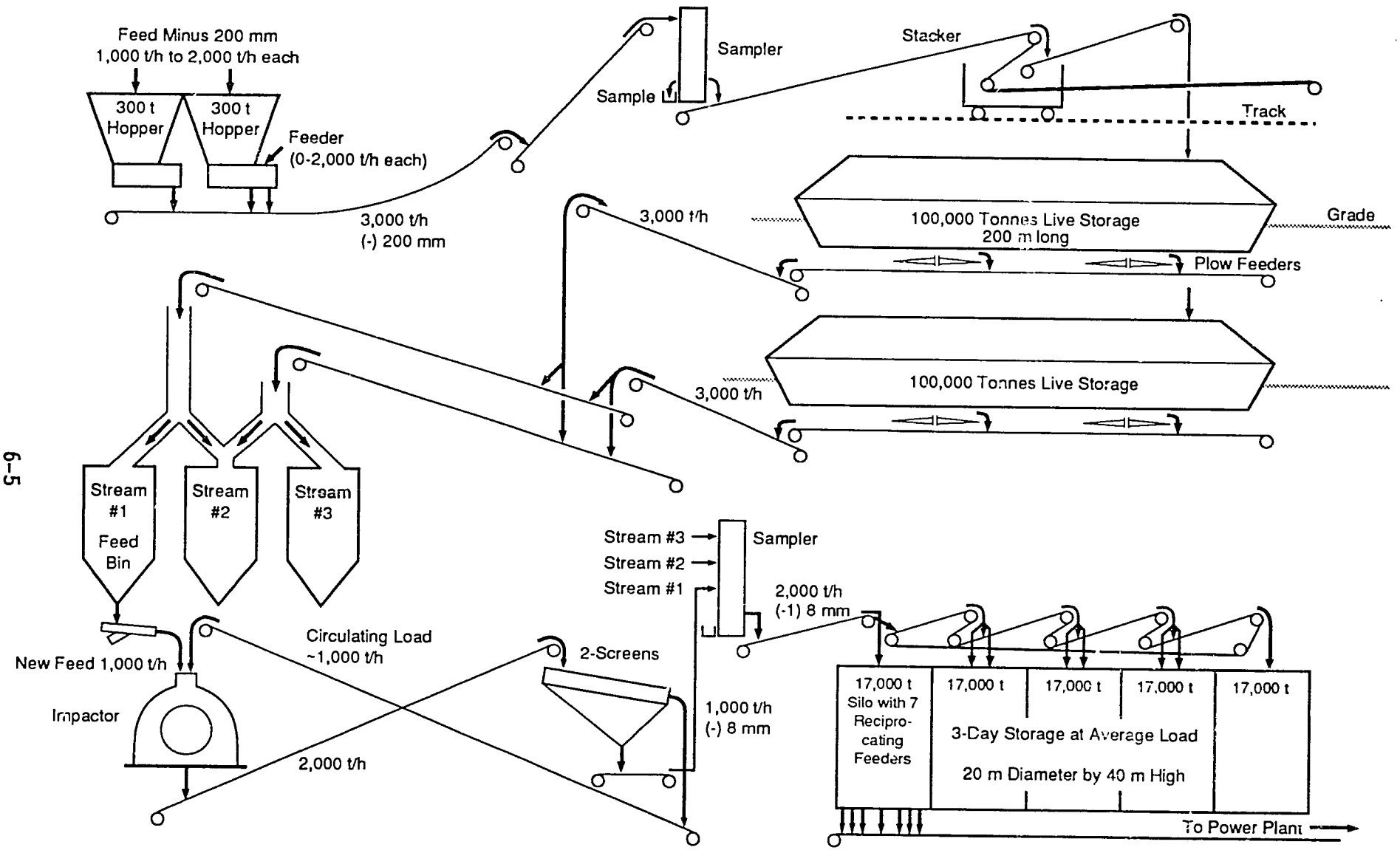

Figure 6-1 Flow Sheet – Oil Shale Processing Plant
400 MW Full Scale Plant

impactor which is in closed circuit with two vibrating screens. The system produces a minus 8 mm product which is conveyed to a common sampler before it is conveyed to storage. The storage consists of five concrete silos which have a total feed capacity of three days operation for the power plant. Each silo is equipped with seven variable speed feeders. By withdrawing from two or more silos, the feed to the boiler is adjusted to meet the performance fuel specification.

6.2.4 Mine Services Facility

The mine services facility will be an expansion of the facilities of the smaller demonstration mine to accommodate the increase in the number of employees and equipment. Truck bays to accommodate the 136 tonne trucks will be added. The truck bays used for the 77 tonne trucks will be used for the maintenance of other equipment. The warehouse, change house, training room, offices and cafeteria will be expanded accordingly.

6.2.5 Mining and Processing Economics

Details of the oil shale mining and processing plant economics for the 400 MW plant are included in the Mining Report (Appendix 5). These details are of the same magnitude as prepared for the 20 MW and 50 MW plants. The summary of the cash flow analysis for the mine and shale processing plant is presented in Table 6-1.

6.2.6 Spent Shale Ash Disposal

Disposal of the wetted spent shale ash is by haulage with 136 tonne trucks to the out-of-pit waste pile for the first two years of operation. In the third year the spent shale will be hauled to the backfill operation of the pit. This operation is large enough to support its own fleet of equipment, which includes two front end loaders with a 10 cubic metre bucket, four 136 tonne trucks and two bulldozers for leveling at the out-of-pit waste pile and in the pit backfill operation. This operation is scheduled for 24 hours per day for each day of the year. It will require a total of 44 employees to handle the spent shale ash.

Table 6-1

SUMMARY OF 400 MW PLANT OIL SHALE MINING AND PROCESSING COSTS

	50/50 Debt-Equity US $1,000	80/20 Debt-Equity US $1,000
Capital Cost		
Mine Development	30,915	30,915
Mine Equipment	66,012	66,012
Process Plant Facilities	50,889	50,889
Spare Parts	5,000	5,000
Working Capital	10,000	10,000
Capitalized Interest During Construction	24,423	39,075
TOTAL	187,239	201,891
Operating Costs and Other Costs		
Annual Cost[a]	60,386	53,236
Product Mined and Processed		
Annual Tonnes x 1,000	7,783	7,783
Unit Cost		
US $/Tonne (weighted average)	7.76	6.84
US $/$10^6$Btu (weighted average)	1.56	1.38

(a) Year 12 costs taken as 25-year average.

6.2.7 Spent Shale Disposal Economics

The summary of these findings are presented in Table 6-2.

6.2.8 Operating Requirements

The manpower and utility requirements of the 400 MW mine and shale processing facilities are as follows:

- Total men - 396 (including 2 expatriates)
- Purchased Power - 123,800,000 Kwh/year
- Water (ex. ash wetting) - 2,575,000 liters/day
  - 773,000 cubic meters/year

6.3 INSTALLED CAPITAL COST FOR INTEGRATED PROJECT

Budget limitiations did not permit the preparation of conceptual designs for the 100 MW Power Block facilities. Pursuant to instructions from USAID a factored estimate approach was employed using the data developed for the previous 50 MW case study and data available to Bechtel for recent similar size power projects employing a Powerflow boiler. Pyropower provided a separate cost estimate for a 100 MW boiler fueled with Sultani oil shale.

Both on-site and off-site infrastructure costs are provided for in integrated capital cost described in Section 6.3.1.

For this case study, the off-site infrastructure includes housing and community facilities for the integrated project employees and families.

The estimated project staffing includes:

o Mining and Shale Processing	396
o Power Block	630
o Project Management	20
Total Staff	1,046

Table 6-2

SUMMARY OF 400 MW PLANT SPENT SHALE DISPOSAL COST

	50/50 Debt-Equity US $1,000	80/20 Debt-Equity US $1,000
Capital Cost		
Equipment	6,368	6,368
Spare Parts	800	800
Working Capital	900	900
Capitalized Interest During Construction	404	646
TOTAL	8,472	8,714
Operating Costs and Other Costs		
Annual Cost (weighted average)	6,378	5,987
Spent Shale Hauled		
Annual Tonnes x 1,000 (wt. avg.)	6,127	6,127
Unit Cost		
US $/Tonne (weighted average)	1.04	0.98

6.3.1 Capital Cost Estimate

While a factored cost estimate has been created, the methodology and cost estimating approach employed in Sections 4.6.1 and 5.6.1 was followed here for the Commercial Scale Project.

The capital cost estimate for power plant is shown under Item (A) in Table 6-3. In developing these estimates the cost impact on major equipment purchased in the worldwide market and maximum use of locally available materials and labor has been assumed. This recognizes the indigenous craft skills developed on existing thermal power plants in Jordan. The capital cost for the 4x100 MW integrated project is considered to have an accuracy of ±30 percent.

Cost Estimate Qualifications and Assumptions. The following cost estimate qualifications and assumptions were made:

- All costs are mid-1988 price level.
- Allowance of funds during construction has been based on 10 percent/yr. per JEA.
- Any future escalation during construction is excluded.
- A boiler price based on an adjusted Pyropower Corporation quotation.
- A 48 hour week and composite direct manual wage rate of $3.00/hour is assumed for power plant construction. This information was provided by JEA.
- It is assumed that foundations will be on spread footings.
- It is assumed that oil shale will be delivered at inplant silos sized and ready for burning per the mine plan.

Other assumptions were made as follows:

- Licensing or environmental regulatory requirement will not restrain the EPC schedule
- Extremes of climatic conditions are not expected to occur at the site area.
- Construction supervisors/advisors would be provided by suppliers of imported major equipment such as boiler and turbine generator.

TABLE 6-3

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COMMERCIAL SCALE INTEGRATED PROJECT SUMMARY OF COSTS
($ in 1000, Mid-1988 Price Level)

		COST $
A)	POWER PLANT:	
	Inplant Fuel Handling	$ 7,600
	Steam Generator + Stack + Baghouse	290,100[a]
	Turbine, Cond, F/Wtr, Etc.	104,600
	Ash Handling	9,500
	General Facilities:	
	Tankage	2,900
	Cooling System	12,400
	Fire Protection	7,600
	Waste Water	2,900
	Electrical	22,800
	Control/Instrumentation	13,300
	Site Improvement	8,600
	Miscellaneous	19,000
	Building:	
	Turbine	4,800
	Boiler Foundation and Structure	28,500
	Auxiliary/Control	6,700
	Water Treatment	1,000
	Admin/Warehouse	6,700
	Yard Facility	1,900
	Services Building	5,700
	Switch Yard:	11,200
	Sub Total Plant Cost:	$567,800
	Owner's Cost/Working Allowance for Funds During Construction:	$ 164,300
	Other's Allow (see 4.6.1 B):	$ 28,400
	Sub Total Owner's Capital Costs:	$ 192,700
	TOTAL POWER PLANT COSTS:	$ 760,500
B)	ALLOWANCE FOR OFF-SITE INFRASTRUCTURE:	$ 45,000
C)	MINING & SHALE PROCESSING COSTS (Table 6-1)	$ 137,239
D)	ASH & OVERBURDEN WASTE DISPOSAL (Table 6-2)	$ 8,472
	TOTAL INSTALLED PROJECT CAPITAL COSTS (50/50 Debt/Equity)	$1,001,211
	TOTAL INSTALLED PROJECT CAPITAL COSTS (80/20 Debt/Equity)	$1,016,105

(a) Includes $186,000,000 for boiler cost from Pyropower adjusted for Jordan location.

- Availability of a qualified labor force in the number and skills required.
- Conversion rate of one JD is equivalent to $3 USD.

The following Owner's costs are excluded:

- Land and right of way
- Permits and licenses
- Local and import taxes

The following Owner's costs are covered as an allowance added to the facilities cost:

- Owner's administrative and overhead cost
- Owner's consultants and related costs
- Costs of utilities for construction
- Spare parts
- Training of operating personnel

6.3.2 Cash-Flow

The power plant cash flow is based on the anticipated project scheduled for construction in the late 1990s with USA or other foreign purchased equipment, and reflects construction conditions and labor availability in Jordan. The cash flow was plotted with an estimated percentage of expenditure of total capital cost versus thepercentage of time of completion of the project. The cost curve for power block only is presented in Figure 6-2. This assumes each 100 MW component is started six months after the previous unit construction gets underway. A three-year mine development program parallel the power block construction.

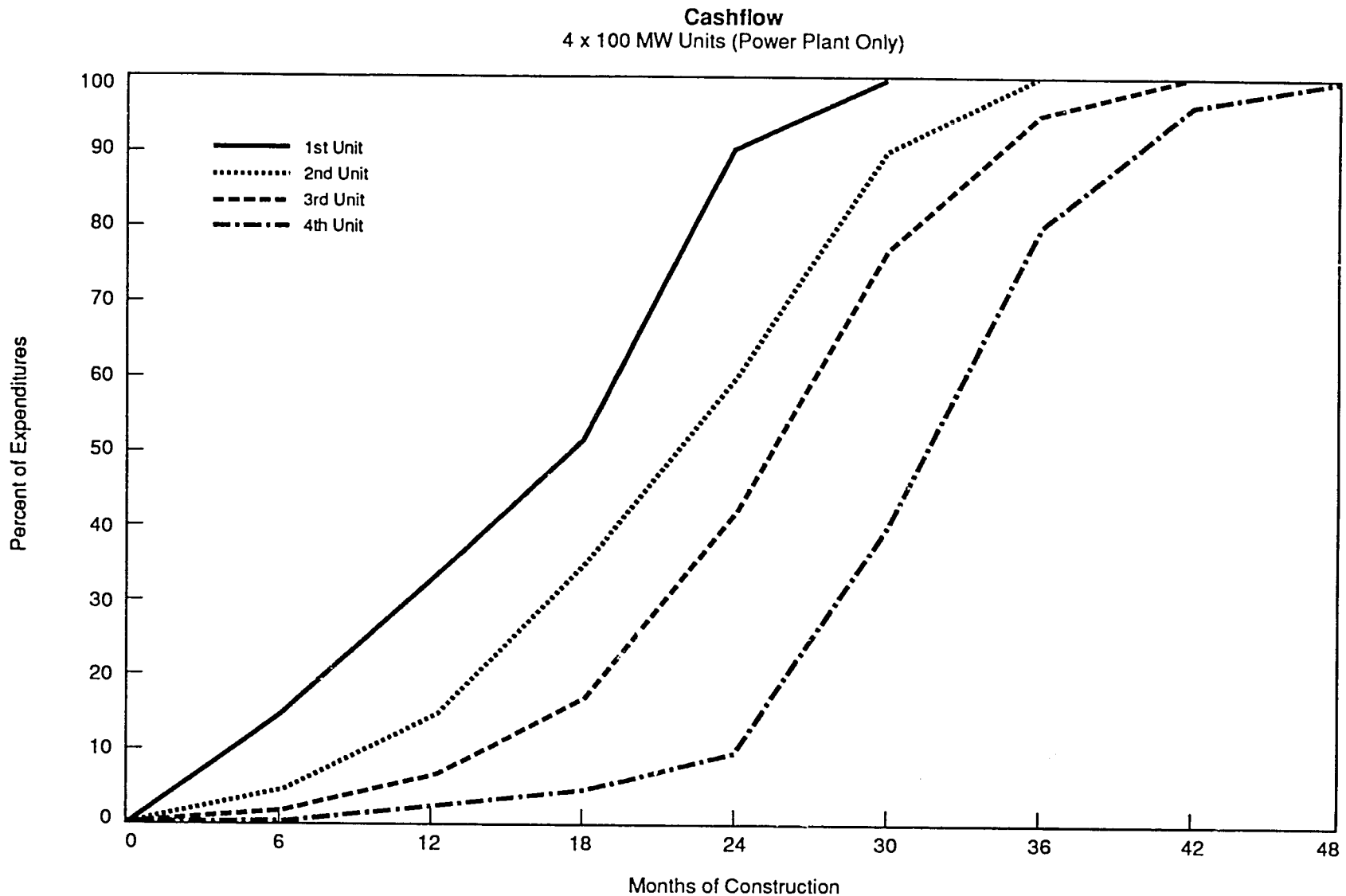

Figure 6-2 Jordan Oil Shale to Power Study

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6.4 INTEGRATED PROJECT OPERATING COSTS

6.4.1 Power Block Operating Requirements

First year operating costs, including fuel costs and waste disposal costs, are presented in Table 6-4. All costs are at mid-1988 price level.

Total first year operating costs include fixed and variable operating and maintenance costs, fuel (oil shale) costs. An explanation of each item follows.

Fixed O&M Costs. Fixed O&M costs include both operating labor and maintenance labor plus materials to operate the power plant. The average labor rate employed corresponds to a direct labor charge plus payroll additives of $3.00/hr. The staffing requirement for power plant operation is presented in Table 6-5.

Annual maintenance costs are estimated as a percentage of the total plant cost (TPC). The percentage varies widely depending on the nature of the processing conditions and type of power plant. The rate of 1.50 percent was selected for this facility. This rate was established by a survey of 456 conventional coal fired power unit. (A somewhat higher rate may be needed for a fluid bed boiler - hence an allowance is provided).

Maintenance labor is typically to be 40 percent and maintenance material 60 percent of the total maintenance cost. Administrative and support labor is assumed to be 30 percent of the operating and maintenance labor.

Variable O&M Costs. Variable O&M costs include the following:

- Variable maintenance costs in addition to the fixed maintenance costs are estimated to be 1 mill per kilowatt hour of operation.
- Utility costs of process water are $0.20 per one thousand gallons. Steam and electricity for plant use are not included as direct costs, but rather impact the plant heat rate.

Table 6-4

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COMMERCIAL SCALE PROJECT
OPERATING REQUIREMENTS - 1ST YEAR

A. DEBT / EQUITY RATIO :========== 50/50

NET GENERATION -	MWe	400.00
CAPACITY FACTOR -	%	75
ANNUAL GENERATION	MKWh/YR	2,628
SUB TOTAL PLANT COSTS (TPC)	$1000	$567,800

FIXED O & M COSTS:	MH	$ /MH	FIRST YEAR COST$1,000
OPERATING LABOR :	436,800	$3	$1,300
MAINTENANCE LABOR :			
@ 40.00% of	1.50%	OF TPC	3,407
MAINTENANCE MATERIAL :			
@ 60.00% of	1.50%	OF TPC	5,110
ADMIN LABOR : F	30.00%	OF O & M LABOR	1,412
SUB TOTAL FIXED O&M COSTS:			$11,229

VARIABLE O & M COSTS:	QUANTITY	UNIT COST	
VARIABLE MAINTENANCE	2628 MKWh	1 MILL/KWH	$ 2,628
PROCESS WATER	13,500,000 GALLON	$0.2/GAL	$ 2,700
GENERAL PLANT CHEMICALS		ALLOW	50
FUEL OIL	1,000,000 GALLON	$0.35/GAL	$ 350
WASTE DISPOSAL (Section 6.2.7)	6,127,000 TN/YR	$1.04 $/TN	$ 6,372
SPECIAL BOILER MAINT		ALLOW	200
SUB TOTAL VARIABLE O&M COSTS:			$12,300

TOTAL FIXED & VARIABLE O&M COSTS:			$23,529
TOTAL FIXED & VARIABLE O&M COSTS (WITH INFLATION)			$24,941
OIL SHALE FUEL (Section 6.2.5) (INCL. INFLATION ADJUSTMENT)	7,783,000 TN/YR	$8.23 $/TN	$64,020

B. DEBT / EQUITY RATIO :========== 80/20

TOTAL FIXED & VARIABLE O&M COSTS (W/O ASH DISPOSAL)			$17,157
WASTE DISPOSAL (Section 6.2.7)	6,127,000 TN/YR	$0.98 $/TN	$ 6,004
TOTAL FIXED & VARIABLE O&M COSTS :			$23,161
TOTAL FIXED & VARIABLE O&M COSTS (WITH INFLATION)			$24,551
OIL SHALE FUEL (Section 6.2.5) (INCL. INFLATION ADJUSTMENT)	7,783,000 TN/YR	$7.25 $/TN	$56,430

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Table 6-5

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COMMERCIAL SCALE PROJECT
POWER BLOCK OPERATION & MAINTENANCE STAFFS

JOB DESCRIPTION	WEEK DAY	WEEK END	SWING	NIGHT	TOTAL
OPERATION					
SUPERINTENDENT	2				2
SHIFT FOREMAN	8	8	8	8	32
FUEL SUPPLY SUPERVISOR	4				4
TECHNICAL SUPERVISOR	4				4
CONTROL ROOM OPERATOR	8	8	8	8	32
CONTROL ROOM TECHNICIAN	2	1	1	1	5
PLANT CHEMIST	2				2
LAB TECHNICIAN	2				2
BOILER OPERATOR	8	8	8	8	32
MISC. OPERATOR	2	2	2	2	8
FUEL MAN	2	2	2	2	8
HELPER OPERATOR	3	3	3	3	12
ENGINEER	8	8	8	8	32
TOTAL OPERATORS	55	40	40	40	175

TOTAL OPERATOR/SHIFT (AVERAGE) 50 MAN/SHIFT

TOTAL MAINTENANCE STAFFS/SHIFT 130 MAN/SHIFT

TOTAL O&M PER SHIFT 180 MAN SHIFT

Staffing Required

Operations	175
Maintenance	455
TOTAL	630

- General plant chemical costs are estimated as an allowance.
- Disposal of ash by truckhaul to a dedicated waste disposal area including loading costs at the power plant, hauling, dumping, spreading, is estimated to cost:
  - At debt/equity 50/50 - $1.04/ton
  - At debt/equity 80/20 - $0.98/ton

Fuel Costs. Fuel (oil shale) costs are an additional variable operating cost. The oil shale costs are as follows:

- At debt/equity 50/50 - $7.76/ton
- At debt/equity 80/20 - $6.84/ton

6.4.2 Busbar Cost of Electricity

Busbar costs of electricity are presented in Table 6-6 including the first year of operation, and for a 30-year levelized cost. Levelized cost is the most appropriate way of representing the varying annual revenue requirements of the power.

Total levelized busbar cost is the sum of a capital cost component, and the operating and fuel cost components. These costs are commonly expressed in mills/kwh. The levelization procedure makes it possible to combine the one-time-only capital cost with a cost that represents the variable annual operating costs over the life of the plant.

The capital cost component is obtained by multiplying the total capital requirement (TCR) by the levelized fixed charge rate (LFCR) and dividing by the number of net kilowatt hours generated per year.

The LFCR includes depreciation, return on equity, interest on debt, property insurance, and general and administrative expenses. The LFCR factor for power block capital costs is 15 percent per year. This factor is typical for USA utility installation. The capital cost component thus obtained is that part of the total cost of generating electricity which is chargeable to the capital investment in each year of plant life.

Table 6-6

BREAKDOWN AND SENSITIVITY OF POWER COSTS TO
CAPITAL AND OPERATING COST COMPONENTS
400 MW COMMERCIAL SCALE INTEGRATED PROJECT

DEBT/EQUITY RATIO : 50/50	1ST YEAR		LEV.	30 YR LEVELIZED	
	$1,000	MILLS/KWH	FACTOR	$1,000	MILLS/KWH
Capital Charges @ 15.3%	$116,357	44	1.00	$ 92,000	35
Operation & Maintenance	25,000	9	1.71	40,000	15
Fuel - Oil Shale	64,000	24	1.86	103,000	39
Total Busbar Cost:	$205,000	78		$236,000	90

DEBT/EQUITY RATIO : 80/20	1ST YEAR		LEV.	30 YR LEVELIZED	
	$1,000	MILLS/KWH	FACTOR	$1,000	MILLS/KWH
Capital Charges @ 13.9	$106,000	40	1.00	$ 83,000	32
Operation & Maintenance	25,000	9	1.77	41,000	15
Fuel - Oil Shale	56,000	21	1.92	94,000	36
Total Busbar Cost:	$187,000	71		$218,000	83

Notes:
- o Capital charges include Power Plant only.
- o Fuel - Oil shale includes capital charges for Mining & Material Handling Plant.

The operating cost and fuel cost components can be expected to escalate, and assuming this escalation is at a constant rate over the plant economic life (25 years for this study per JEA). These variations in cost are converted to a uniform annual amount using a levelizing factor (LF). The LF is the product of the capital recovery factor and the present worth factor adjusted for escalation. The LF factor for O&M's fuel are calculated on the basis of various debt/equity ratios of financing of the project. The calculation of LF factor based on various financial assumptions are summarized and included as Table 6-7.

The levelized component of the total levelized busbar cost for O&M costs, and for fuel cost is obtained by multiplying the first year costs by the respective LF and then dividing by the number of net kilowatt hours generated per year. The net kilowatt hours generation has been calculated on the basis of 75 percent capacity factor. In summary, the total first year and 25 year levelized busbar costs are the sum of the following components:

- Capital cost component
- O&M cost component
- Fuel (oil shale cost component)

The oil shale fuel cost was computed using fixed capital charge rates of 10 percent interest on borrowed capital components plus a 20 percent return on the equity component. This is more typical of mining venture capital charges.

The Off-Site Infrastructure investment was assumed to be self liquidating and is not included in the Busbar rate calculation.

For comparative purposes, the operating and maintenance costs and staffing requirements for a 400 MW coal fired power plant are presented in Tables 6-8 and 6-9. Equivalent cost data for a 400 MW oil fired power plant are presented in Tables 6-10 and 6-11.

These data are used in the Economic Analysis presented in Section 8 and Table 1.3.

Table 6-7

OIL SHALE FIRED POWER PLANT IN JORDAN
FINANCIAL BASIS AND ASSUMPTIONS

1.	Debt Ratio	:	50% at the rate of 9%
2.	Equity	:	50% at the rate of 13.5%
3.	Average Cost of Capital	:	11.25%
4.	Debt Ratio	:	80% at the rate of 9%
5.	Equity	:	20% at the rate of 13.5%
6.	Average Cost of Capital	:	9.9 %
7.	Capital Rate	:	(per JEA) : 15%
8.	Inflation Rate	:	6.0%
9.	Real Escalation Rate	:	0.8%
10.	Book Life of Plant	:	25 Years (per JEA)
11.	Tax Life of Plant	:	15 Years
12.	Levelized Factor		

Debt/Equity = 50/50

Without Real Escalation	:	1.71
With Real Escalation	:	1.86

Debt/Equity - 80/20

Without Real Escalation	:	1.77
With Real Escalation	:	1.92

Capital charges per above financial assumptions based on EPRI's method of calculation:

Debt/Equity = 50/50
- Capital Charges = 15.3%

Debt/Equity = 80/20
- Capital Charges = 13.9%

Table 6-8

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COAL FIRED PLANT OPERATION & MAINTENANCE COST - 1ST YEAR

A. DEBT / EQUITY RATIO :========== 50/50

NET GENERATION -	MWe	400.00
CAPACITY FACTOR -	%	75
ANNUAL GENERATION	MKWh/YR	2,628
SUB TOTAL PLANT COSTS (TPC)	$1,000	$620,000

FIXED O & M COSTS:	MH	$ /MH	FIRST YEAR COST$1,000
OPERATING LABOR :	351,936	$3	$1,100
MAINTENANCE LABOR :			
@ 40.00% of	1.50%	OF TPC	3,720
MAINTENANCE MATERIAL :			
@ 60.00% of	1.50%	OF TPC	5,580
ADMIN LABOR :	30.00%	OF O & M LABOR	1,446
SUB TOTAL FIXED O&M COSTS:			$11,846

VARIABLE O & M COSTS:	QUANTITY	UNIT COST	
VARIABLE MAINTENANCE	2,628 MKWh	1.0 MILL/KWH	$ 2,628
PROCESS WATER	13,500,000 GALLON	0.2 $/GAL	$ 2,700
GENERAL PLANT CHEMICALS		ALLOW	50
FUEL OIL	1,000,000 GALLON	0.35 $/GAL	$ 350
WASTE DISPOSAL (Section 6.2.7)	228,950 TN/YR	$10.00 $/TN	$ 2,290
SPECIAL BOILER MAINT		ALLOW	0
SUB TOTAL VARIABLE O&M COSTS:			$ 8,018

TOTAL FIXED & VARIABLE O&M COSTS:			$19,864
TOTAL FIXED & VARIABLE O&M COSTS (WITH INFLATION)			$21,056
COAL FUEL (INCL. INFLATION ADJUSTMENT)	1,205,000 TN/YR	$82.27 $/TN	$99,139

B. DEBT / EQUITY RATIO :========== 80/20

TOTAL FIXED & VARIABLE O&M COSTS (W/O ASH DISPOSAL)			$17,574
WASTE DISPOSAL (Section 6.2.7)	228,950 TN/YR	$10.00 $/TN	$ 2,290
TOTAL FIXED & VARIABLE O&M COSTS :			$19,864
TOTAL FIXED & VARIABLE O&M COSTS (WITH INFLATION)			$21,056
COAL FUEL (INCL. INFLATION ADJUSTMENT)	1,205,000 TN/YR	$58.77 $/TN	$70,814

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Table 6-9

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COAL FIRED PLANT
OPERATION & MAINTENANCE STAFFS

JOB DESCRIPTION	WEEK DAY	WEEK END	SWING	NIGHT	TOTAL
OPERATION					
SUPERINTENDENT	2				2
SHIFT FOREMAN	6	6	6	6	24
FUEL SUPPLY SUPERVISOR	2				2
TECHNICAL SUPERVISOR	4				2
CONTROL ROOM OPERATOR	6	6	6	6	24
CONTROL ROOM TECHNICIAN	2	1	1	1	5
PLANT CHEMIST	2				2
LAB TECHNICIAN	2				2
BOILER OPERATOR	6	6	6	6	24
MISC. OPERATOR	2	2	2	2	8
FUEL MAN	2	2	2	2	8
HELPER OPERATOR	3	3	3	3	12
ENGINEER	6	6	6	6	24
TOTAL OPERATORS	45	32	32	32	141

TOTAL OPERATOR/SHIFT (AVERAGE) 40 MAN/SHIFT

TOTAL MAINTENANCE STAFFS/SHIFT 142 MAN/SHIFT

TOTAL O&M PER SHIFT 182 MAN SHIFT

EMPLOYMENT: 637 MEN

Staffing Required

Operations	175
Maintenance	455
TOTAL	630

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Table 6-10

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW OIL FIRED PLANT
OPERATION & MAINTENANCE COST - 1ST YEAR

A. DEBT / EQUITY RATIO :========== 50/50

NET GENERATION -	MWe	400.00
CAPACITY FACTOR -	%	75
ANNUAL GENERATION	MKWh/YR	2,628
SUB TOTAL PLANT COSTS (TPC)	$1,000	$443,000

FIXED O & M COSTS:	MH	$ /MH	FIRST YEAR COST$1,000
OPERATING LABOR :	262,080	$3	$ 800
MAINTENANCE LABOR :			
@ 40.00% of	1.50%	OF TPC	2,658
MAINTENANCE MATERIAL :			
@ 60.00% of	1.50%	OF TPC	3,987
ADMIN LABOR :	30.00%	OF O & M LABOR	1,037
SUB TOTAL FIXED O&M COSTS:			$ 8,482

VARIABLE O & M COSTS:	QUANTITY		UNIT COST	
VARIABLE MAINTENANCE	2628 MKWh	0.5	MILL/KWH	$ 1,314
PROCESS WATER	13,500,000 GALLON	0.2	$/GAL	$ 2,700
GENERAL PLANT CHEMICALS			ALLOW	50
FUEL OIL	1,000,000 GALLON	0.35	$/GAL	$ 350
WASTE DISPOSAL (Section 6.2.7)	0 TN/YR	$10.00	$/TN	$ 0
SPECIAL BOILER MAINT			ALLOW	0
SUB TOTAL VARIABLE O&M COSTS:				$ 4,414
TOTAL FIXED & VARIABLE O&M COSTS:				$12,896
FUEL OIL	503,000 TN/YR	$199.81	$/TN	$100,502

B. DEBT / EQUITY RATIO :========== 80/20

TOTAL FIXED & VARIABLE O&M COSTS (W/O ASH DISPOSAL)			$12,896
WASTE DISPOSAL (Section 6.2.7)	0 TN/YR	$10.00 $/TN	$ 0
TOTAL FIXED & VARIABLE O&M COSTS :			$12,896
FUEL OIL	503,000 TN/YR	$141.04 $/TN	$70,943

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Table 6-11

JORDAN OIL SHALE TO POWER PREFEASIBILITY STUDY
400 MW COAL FIRED PLANT
OPERATION & MAINTENANCE STAFFS

JOB DESCRIPTION	WEEK DAY	WEEK END	SWING	NIGHT	TOTAL
OPERATION					
SUPERINTENDENT	2				2
SHIFT FOREMAN	4	4	4	4	16
FUEL SUPPLY SUPERVISOR	2				2
TECHNICAL SUPERVISOR	4				4
CONTROL ROOM OPERATOR	4	4	4	4	16
CONTROL ROOM TECHNICIAN	2	1	1	1	5
PLANT CHEMIST	2				2
LAB TECHNICIAN	2				2
BOILER OPERATOR	4	4	4	4	16
MISC. OPERATOR	2	2	2	2	8
FUEL MAN	1	1	1	1	4
HELPER OPERATOR	3	3	3	3	12
ENGINEER	4	4	4	4	16
TOTAL OPERATORS	36	23	23	23	105

TOTAL OPERATOR/SHIFT (AVERAGE) 30 MAN/SHIFT

TOTAL MAINTENANCE STAFFS/SHIFT 101 MAN/SHIFT

TOTAL O&M PER SHIFT 131 MAN SHIFT

EMPLOYMENT: 459 MEN

Staffing Required

Operations	175
Maintenance	445
TOTAL	630

Section 7
Environmental Considerations

Section 7

ENVIRONMENTAL CONSIDERATIONS

The following observations were made by the engineering staffs involved with development of the conceptual designs for the integrated project facilities.

7.1 MINE AND MATERIALS HANDLING SYSTEM

Prior to the commencement of on-site operations, site specific environmental baseline studies should be conducted to develop data in all environmental media areas. The key areas to be addressed are:

- Development of protective measures for both surface and ground water supplies
- Determination of measures to mitigate surface and ground water contamination due to mining
- Further soil testing of the overburden for chemical properties and their suitability for revegetation
- Site specific air quality monitoring and modeling to ensure that models which are developed are predictive of the mining operation to aid in developing necessary mitigation practices
- Development of protective measures for noise levels and the determination of measures to mitigate noise levels due to mining for protecting the health and welfare of the miners and the general public.

The program should also develop specific plans and measures related to special conditions, socioeconomic impacts, archeology, paleontology historical, recreation and human health effects.

In the mine development planning, as described in the Mining Report (Appendix 5), some of the measures to protect the surface and ground water from contamination are proposed. Excavation of ditches around the pit area and the out-of-pit waste pile are measures to prevent rain water run-off from becoming contaminated with disturbed areas. Rain water run-off from disturbed

areas such as the waste pile, haul roads and the pit will be collected in sedimentation ponds and will have zero discharge. This will prevent any contaminent due to mining from entering the ground water.

Air pollution from the mine area will be mostly fugitive dust. The operation will be equipped with water tankers and the haulroads and pit roads will be sprayed with water from these tankers on a periodical basis.

The major noise level at the mine will occur at the time of blasting the overburden. The use of delays and good blasting techniques will decrease the level of air blast. The use of blasting the oil shale is not required, since selective mining will be accomplished by auger scrapers for the smaller mines and surface miners for the larger mine.

Another area of concern at the mine is the disposal of the spent shale ash. Leachability tests of the spent shale ash to evaluate its toxicity are required as well as the testing of the overburden for its chemical properties. The reaction of the spent shale with any constituent of the overburden is unknown. Sections 4.2.6, 5.2.6, 5.2.7, 6.2.7 outline the conceptual plans and costs for ash disposal used in this study. Any modified measures for handling the disposal of the spent shale ash are to be determined in a follow-on study when funded. The use of 20 percent water by weight in the pugging operation was arbitrarily selected and further determinations are required for its adequacy to prevent dusting when the spent shale is dumped from a truck or to conserve water if the mixture is too wet.

Environmental consideration at the oil shale process crushing plant will be air pollution and noise level. Dust collectors will be used to prevent air pollution at the process plant. Air ducts will pick-up dust from all dust producing sources in the storage areas as well as the processing area. The major sources of noise will occur at the impact crushers and the vibrating screens. Enclosure of this equipment may be required if the noise level exceeds the allowable level for workers exposed to the noise.

7.2 BOILER AND POWER PLANT

In using oil shale as a fuel for power generation, three potential air pollution emissions are of primary interest: sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter. Other significant environmental concerns are: liquid effluents, solid waste discharge, fuel trace elements leachate and noise. The discussion in this section reviews some of the international regulations or guidelines for these emmissions or discharges.

Jordan has no emmissions standards or guidelines that would apply to the proposed project. However, the Electricity Authority of Jordan has requested use of international environmental protection regulations for this study to avoid hazards due to emmission of gases and contamination of underground water due to solid disposal.

In principle, the pollutants in effluents from the power block can be controlled to values such that when added to the pre-existing (background) levels, the resulting concentrations are within recommended exposure guidelines. However, in order to set effluent limits for new facilities with confidence that health effects or unacceptable environmental impacts will not occur, it is necessary to know the existing levels of pollutants in the affected environment.

This study is based partly on the guidelines of the World Bank (Reference 1) because of their ready availability in a usable form. The World Bank guidelines go beyond those of the World Health Organization in that specific recommendations for some, but not all, effluent limitations are provided on a generalized basis. The term "guidelines" as used in this report will be understood to mean the World Bank guidelines unless otherwise stated.

7.2.1 Gaseous Emissions

Emission standards specify the maximum amount of a given pollutant which can be released into the atmosphere from a given source. Emission standards are set in most countries on an industry by industry or plant by plant basis. Some countries have established nationwide "emission guidelines" which serve

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as as reference point for discussions between regulatory authorities and the industry or plant concerned (Reference 3).

Sulfur Dioxide. Sulfur dioxide presents some unusual problems. It is a common gaseous pollutant from many fossil fuel burning sources as well as ferrous and non-ferrous smelting operations. As a consequence, it is virtually ubiquitous and presents a background value practically everywhere.

World Bank emission standards for boilers are established with due regard to (1) background levels of sulfur dioxide, and (2) placing a reasonable limit on absolute emissions. These guidelines are presented in Table 7-1.

Table 7-2 summarizes the sulfur dioxide emission limits of a number of countries for comparison.

From Table 7-1 it is seen that two independent criteria must be met. Criterion I is primarily a function of background conditions and sulfur content of feedstock. Criterion II is a function of background conditions, local meteorology and terrain, and stack height. Each criterion when applied results in a certain sulfur removal requirement (SRR). When determining allowable emissions, the highest SRR calculated should be applied. Criterion II requires an appropriate mathematical dispersion model to determine actual concentrations. Such a model does not exist for the Sultani site area.

The pilot test results indicate excellent sulfur capture by the calcium in the oil shale. Assuming low existing pollution levels at the Sultani plant location, it is possible that 90 percent SO_2 removal in the Pyropower boiler is adequate to meet the World Bank requirements for a these power plants of 20-50 MW capacity. However, it should be noted that more than 95 percent SO_2 removal is required to meet the emission requirements of a Typical U.S. Industrial plant. Actual SO_2 removal level to be selected for design purposes should involve a thorough review of the background levels of sulfur dioxide, which is thought to be low at Sultani.

Table 7-1

SULFUR EMISSION GUIDELINES

Background Air Quality (sulfur dioxide basis)	Sulfur Background Levels (Ug/M^3) Annual Average	Max. 24-Hour	Criterion I Max. SO_2 Emission (TPD)[a]	Criterion II Max. allowable ground level increment to ambient (ug/m^3 One Year Average)
Unpolluted	50	200	500	50
Moderately Polluted[b]				
Low	50	200	500	50
High	100	400	100	10
Very Polluted[c]	100	400	100	10

(a) Tons per day.

(b) For intermediate values beteen 50 and 100 ug/m^3 linear interpolations should be used.

(c) No projects with sulfur dioxide emissions are recommended in these areas.

Table 7-2

SULFUR DIOXIDE EMISSION REGULATIONS OR GUIDELINES APPLICABLE TO INDUSTRIAL BOILERS[a]

Country or Organization	Solid Fuels	Liquid Fuels[b]
European Economic Community	None	Fuel oil in zones exceeding specified levels of ambient SO_2: after June 1978: 2% S after June 1983: 1% S
England	Specified stack height to limit short-term ambient concentration (nominal 3 min. avg. 0.17 ppm SO_2)	Max. % S (effective Oct. 1980): light (12.5 cS/180°F): 3.5% inter (30 cS/180°F): 4.0% heavy (70 cS/180°F): 4.5% extra (115 cS/180°F): 5.0%
France	Stack hieght criteria, and: Rhone Zone: 1% S in fuel Paris and North Zone: 2 g SO_2/th (2.2 lb SO_2/MBtu) Power Plants: low sulfur fuel if ambient SO_2 1000 g/m^3	No. 1 oil: 2% S No. 2 oil: 4% S
Federal Republic of Germany	4 TJ/hr thermal input (1100 MWt): 1% S 4 TJ/hr: 2.75 g SO_2/kWh (1.7 lb SO_2/MBtu) Plus specified stack height to limit ambient concentration	Stack: 30 m: 0.5% S 0.04 - 4.0 TJ/h: 1% S
Spain	Bituminous or anthracite: 2400 mg/Nm^3 in flue gas Lignite: Power Plant: 9000 mg/Nm^3 Other: 6000 mg/Nm^3	Power Plants: 3000 - 4500 mg/Nm^3 Other: No. 1 oil: 1700 - 2500 mg/Nm^3 No. 2 oil: 3400 - 5000 mg/Nm^3
Sweden	--	Boilers: 300 MW: 20 kg/t fuel Heavy Fuel Oil (max.): General: 2.5% S South and Central: 1.0% S After 1981, except North: 1.0% S After 1984, everywhere: 1.0% S
United States	New Power Plants: 73 MWt (250 MBtu/hr heat input): 520 ng/J (1.2 lb/MBtu) maximum; SO_2 reduction (30 day avg.) of 70-90% Other New Steam Generators: 73 MWt: 520 ng/J (1.2 lb/MBtu) maximum Plus Best Available Control Technology (BACT)	New Power Plants: 73 MWt: 350 ng/J (0.8 lb/MBtu) maximum; SO_2 reduction of 90% if emissions greater than 86 ng/J (0.2 lb/MBtu) Other New Steam Generators: 73 MWt: 340 ng/J (0.8 lb MBtu) maximum Plus BACT

(a) Adapted from "Air Pollution Constraints on Increased Coal Use by Industry, An International Perspective," Journal of the Air Pollution Control Association, Vol. 31, No. 4, April 1981.

(b) Excludes gas-oil.

Nitrogen Oxides. Two types of standards are generally used for nitrogen oxides -- ambient and emission. Ambient standards express the allowable concentration of a contaminant in the air surrounding the plant site, following discharge and mixing. Ambient levels are essential for determining possible environmental damage and for evaluating adverse physical, health, and other effects upon the surrounding area and its inhabitants.

Emission standards express the allowable concentrations of a contaminant at the point of discharge, before any mixing with the surrounding medium (air).

Ambient air concentrations of nitrogen oxides, expressed as NO_2, should not exceed the following:

Annual Arithmetic Mean:	100 ug/m^3 (0.05 ppm)

Again a dispersion model is needed to evaluate this criteria. Nitrogen oxide from Pyropower boiler is expected to be 0.6 lbs/million Btu boiler heat input. This is equal to a typical U.S. Industrial Plant NO_x emission and is expected to easily meet the World Bank requirements. The pilot test results indicate acceptable NO_x emissions.

7.2.2 Dust and Particulates

Two sets of guidelines exist: one for the workplace and one for the environment beyond the plant fence.

In the workplace, dust concentration limits are expressed as threshold limit value (TLV) and takes into account the number of hours in the workday and the number of workdays per week. The guidelines recommend that a plant should be designed and operated to provide actual dust levels well below the TLV. The TLVs for dusts based on an 8-hour workday are shown in Table 7-3.

Occupational (In Power Plant Area). Fuel handling at the power plant may need some controls for the protection of workers in the immediate vicinity. Breathing masks can be effective for limited periods of time. The wearing of masks for sustained periods is not recommended because of difficulties in

Table 7-3

TLVs FOR DUSTS
(Based on 8 Hour Workday)[a]

Substance		mg/m^3
Coal Dusts (Bituminous)		
Respirable[b] fraction	5% SiO_2	2.4
Respirable fraction	5% SiO_2	10/(%Si+2)
Inert or Nuisance Dusts[c]		
Respirable		5
Total		15

(a) For workdays other than 8 hours, apply the following correction factor:

Correction Factors = 8/Workday Hours

(b) Respirable dust is less than 10 um in size and is measured by monitoring devices that correlate with pulmonary deposition.

(c) If quartz content is 1% or greater use quartz formula (10/(%Si+2).

enforcing their use. The occupational guidelines provided by the World Bank show TLVs for 8 hours exposure. The plant should be designed to give levels well below these values (no more than one-half the TLV is recommended).

General Public. The guideline for stack discharges of particulate matter (dust) is:

<50 mg/m^3 (dry)

This guideline is applicable to total inert dust (>1% SiO_2) containing no carcinogenic compounds. However, large variations exist from one project to another. As a rule, the following levels should not be exceeded:

- Stack Emission. When background levels of dust are high, dust emissions from the stack should not be greater than 100 mg/m^3
- Ambient Levels. Annual geometric mean should be 100 ug/m^3. Maximum 24-hour concentration should be 500 ug/m^3

If the dust under consideration is affecting vegetation, the annual mean and 24-hour figures should be adjusted downwards.

The stack emissions are to be added to any fugitive emissions (uncontrolled or non-point sources of dust) and other point sources in the plant such as from fuel processing. Modeling of all plant emissions is required when a facility is being designed in order to determine if recommended ambient levels are exceeded.

Table 7-4 summarizes the particulate emissions limits of a number of countries for comparison.

The dust emission from the stack in the conceptual design is about 0.03 lbs/Btu heat input. This should be adequate to meet World Bank requirements.

7.2.3 Liquid and Solid Waste

Combustion wastes consist of fly ash and bottom ash. About 99 percent of the fly ash is assumed to be retained by pollution abatement equipment. Bottom ash is recovered from the bottom of the boiler.

Table 7-4

PARTICULATE EMISSION REGULATIONS OR GUIDELINES APPLICABLE TO INDUSTRIAL BOILERS[a]

Country	Solid Fuels	Liquid Fuels[b]
England	Heat Input Rate[b] MBtu/hr (MWt); Emission Rate lb/hr (kg/hr) (lb/MMBtu) 10 (2.9) 7.6 (3.4) (0.76) 100 (29.3) 45 (20) (0.45) 200 (58.6) 90 (41) (0.45) 300 (87.9 132 (60) (0.44) 500 (150) 218 (99) (0.44) New Power Plants: 450,000 lb steam/hr (approximately 150 MWt input): 115 mg/Nm^3 Opacity: Ringelmann No. 2	Heat Input Rate[b] MBtu/hr (MWt); Emission Rate lb/hr (kg/hr) (lb/MMBtu) 10 (2.9) 2.2 (1.0) (0.22) 100 (29.3) 16 (7.3) (0.16) 200 (58.6) 26 (12) (0.13) 300 (87.9) 35 (16) (0.12) 500 (150) 54 (24) (0.11)
France	3000 lb/hr (41 MWt): 1000 mg/lb (0.56 lb/MBtu) 8000 lb/hr (108 MWt): 200 mg/lb (0.11 lb/MBtu) 8000 lb/hr: 150 mg/lb (0.08 lb/MBtu) Fuel: 20% ash: 500 mg/Nm^3 Fuel: 20% ash: 350 mg/Nm^3	
Federal Republic of Germany	Particulate: 10: 250 mg/Nm^3 @ 0 m^3/hr to 100 mg/Nm^3 @ 70,000 m^3/hr Total Particulate: 500 mg/Nm^3 @ 0 m^3/hr to 150 mg/Nm^3 @ 70,000 m^3/hr Water-Tube Boilers: 500,000 m^3/hr: lignite: 100 mg/N^3 bituminous: 150 mg/Nm^3 Opacity: Ringelmann No. 1	Total Particulate 150 mg/Nm^3 @ 0 m^3/hr to 50 mg/nM^3 @ 100,000 m^3/hr; 50 mg/nM^3 100,000 m^3/hr;
Spain	New Power Plants: General Zones / Special Zones 50 MW: 500 mg/Nm^3 / 400 mg/Nm^3 50-200 MW: 350 / 300 200 MW: 200 / 200 Opacity: Ringelmann No. 1 except 2 min/hr at No. 2	New Power Plants: All Zones 50 MW: 200 mg/Nm^3 50-200 MW: 175 200 MW: 150
Sweden	--	New Boilers: 300 MW: 1.5 g/kg 300 MW: 1.0 g/kg
United States	New Power Plants: 73 MWt (250 MBtu/hr heat input): 13 ng/J (0.03 lb/MBtu) Other New Steam Generators: 73 MWt: 43 ng/J (0.1 bl/MBtu) Opacity: 20%	Same as solid fuel
World Bank	Total Particulate in Stack Gas: 100 mg/Nm^3 (dry); 150 mg/Nm^3 is acceptable if plant is located in rural area and ambient air quality standards are met	Same as solid fuel

(a) Adapted from "Air Pollution Constraints on Increased Coal Use by Industry, An International Perspective," Journal of the Air Pollution Control Association, Vol. 31, No. 4, April 1981.

(b) Complete table ranges from 1.25 to 575 MBtu/hr.

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Mine-mouth plants can dispose of these wastes in portions of the mine from which the fuel was removed where local conditions are favorable. Whatever disposal technique is used, leaching of water-soluable constituents of the ash into the underlying soil, and perhaps into the groundwater, can occur. A liner cf impervious material such as clay is effective in preventing groundwater contamination.

7.2.4 Trace Elements in Fuel

Trace elements are generally defined as those with a relative abundance in the earth's crust of 0.1 percent (one part per thousand) or less. Many of these elements in fuel are enriched in fuel ash, a combustion by-product, relative to their crustal abundance, and some are elevated to toxic concentration.

From a single 20 or 50 MW plant, it is unlikely that trace element emissions will be a problem, assuming that typical amounts occur in the fuel. However, it is important to know the emission levels of these substances in order to prevent problems as fuel use becomes more widespread. Ultimately it may be desirable to create a dispersion model for the underground aquifer.

7.2.5 Noise

There are considerable variations in the recommended allowable noise levels emitted by the many individual sources existing in the environment.

Continuous noise levels above 90 dBA have detrimental effects on human performance, especially in so-called "noise-sensitive" function, such as vigilance tasks, information gathering, and analytical processes. Noise levels below 90 dBA can be disruptive, particularly if they have predominantly high frequency components, and are intermittent, unexpected and uncontrollable.

Noises resulting from industrial operations are generally confined within the plant structure. Machinery and equipment are the main sources, and the effects are felt mostly by the individual workers.

Controls may be accomplished through measures at the source (relocation, vibration control, etc.); installation of acoustical shields, enclosures, or other barriers to interrupt the path of the sound; or through limiting the duration of the exposure by the receiver. The first two of these measures will help reduce the noise levels in the environment outside the plant. Around boilers, limiting the duration of the exposure is common, and simple earplugs are frequently used by workers temporarily entering high noise areas.

In the absence of sensitive noise receptors such as schools and hospitals in the immediate vicinty of a facility, noise suppression sufficient to protect the workers in the plant usually results in acceptable noise levels outside the plant.

7.2.6 Secondary Environmental Impacts

Secondary effects on the environment are the consequences of a population influx in the town or region. They include water and power distribution, sewage collection and treatment, housing, schools and roads

In developed countries, the ratio between employment in the new plant and new employment in the region is usually one to seven, or one to eight. Although the conditions are different in less developed countries, the World Bank recommends the application of the same ratio. The goal of the guidelines is only to draw attention to the potential trouble and to suggest economical solutions in certain areas, thus preventing the expansion of urban slums.

In the forecasts for water and power consumptions, not only the plant requirements but also the town's and region's induced future uses should be taken into consideration.

Sewage collection and treatment should receive special attention. Domestic and industrial garbage disposal has created problems in some developments. The disposal should be addressed in the planning stages and a suitable dump area identified.

7.3 ASH DISPOSAL

(See comments in Section 7.1)

7.4 GROUND WATER AVAILABILITY AND PROSPECTS FOR DEGRADATION

The Government of Jordan has indicated that up to 2 million cubic meters per year will be made available to the Sultani project from the underlying aquifer. Water requirements for the project are shown in Table 7-5:

Table 7-5

ESTIMATED SULTANI WATER REQUIREMENTS

	Cubic Meters Per Year		
	20 MW	50 MW	400 MW
Mine and Shale Processing	455,000	761,000	773,000
Power Block	3,000	6,000	42,000
Infrastructure[a]	80,000	140,000	448,000
Total	538,000	907,000	1,263,000

(a) The community services requirements are based on 3.8 people per project employee and a consumption rate of 100 gallons/ day/ person, with no water reclaimation.

The ORNL report (Appendix 6) discusses results of their ash leaching tests. Certain potential bad actors were identified:

- Arsenic
- Cadmium
- Selenium

In the 20 MW and 50 MW operations the potential for damage to the aquifer is too small to be of concern. In the 400 MW case further studies including development of a dilution model are needed to establish whether a problem exists. This matter is deferred for future study when additional funding is established.

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REFERENCES

1. "Environmental Guidelines," The World Bank, Office of Environmental Arrairs, July 1984, Washington, D.C.

2. "The Environmental Effects of Using coal for Generating Electricity," Argonne National Laboratory, Illinois, USA, May 1977 (NTIS Catalog No. PB-267 237).

3. "Air Pollution Constraints on Increased Coal Use by Industry, an International Perspective," by Edward S. Rubin, Journal of the Air Pollution Control Association, Vol. 31, No. 4, April 1981.

Section 8
Economic Analysis

Section 8

ECONOMIC ANALYSIS

The objectives of the previous sections are to present order of magnitude investment costs and operating requirements for several sizes of an integrated project for electric power generation from Sultani oil shale. The objective of this section is to compare these costs with the alternative of continuing construction of additional conventional oil or coal fired power generation plants at Aqaba.

Insufficient information is available on the natural gas resource recently discovered in Eastern Jordan near Risha. Consequently one can only speculate on its impact on the future power supply/demand picture in Jordan. Before a decision is reached to dedicate the gas resource to power generation, studies should made to determine whether industrial use of gas, for instance in fertilizer manufacture, would be of greater benefit to Jordan. As a result of insufficient information this analysis effectively ignores the future use of gas for power generation.

The economic analysis examines only the larger, 400 MW commercial size for the integrated oil shale to power operation because of the poor economies and resulting high cost of power for the 20 MW and 50 MW sizes.

For the 400 MW commercial scale plant, two levels of financing are considered:

- 50/50 Debt/Equity
- 80/20 Debt/Equity

The analysis assumes the following two levels of future conventional fuel prices:

	LEVEL 1	LEVEL 2
o Imported Crude Oil/Fuel Oil	$17/Bbl	$24/Bbl
o Imported Coal	$50/Tonne	$70/Tonne

The methodology employed for this analysis uses the principles set forth in the Technical Assessment Guide for evaluating power generation alternatives published by Electric Power Research Institute (EPRI), reference (TAG, EPRI-P-4463SR-Dec. 1986). Referring to Tables 8-1 through 8-8 (at the end of this section), the economic comparisons were developed as follows:

- Capital Costs

  - The installed capital costs for the power-block in a 400 MW oil shale project are developed in Section 6 of this study. The installed cost for an oil fired power plant was provided by JEA, based on their recent experience at Aqaba I. The installed cost for a coal fired unit was selected by Bechtel from experience with similar size plants adjusted for construction in Jordan with coal terminalling facilities added.

  - A capital factor multiplier was created which reflects the year by year cash flow analysis method including financing costs, depreciation, inflation and real escalation on an annual basis. For each case study this capital factor is listed in the second column of Tables 8-1 through 8-8.

  - The annual cost of capital is listed in column (D) for coal or oil plants and column (I) for oilshale power plants and is computed by multiplying the installed capital cost by the "capital factor".

- O & M Costs

  - Operating and maintenance costs are developed in the tables in Section 6.

  - O & M costs will increase annually due to inflation and real escalation. The results are listed year by year in column (E) for coal and oil plants and column (J) for oilshale fueled plants.

- Fuel Costs

  - It is assumed that funds to purchase coal or oil fuels for the 400 MW power plant must be borrowed at a cost of 10% annually. Further that imported oil or coal prices and oil shale costs and will increase annually due to inflation and real escalation. Column (F) reflects these increasing coal or oil fuel costs over a 25-year period. Column (K) presents oilshale fuel costs.

- o Revenue Required

  - For the coal and oil fueled power plants the annual required revenue to cover capital costs, O&M costs and fuel costs is the sum of columns (D),(E) and (F) and is presented in column (G).

  - For oilshale fueled power plants the annual required revenue is the sum of columns (I), (J) and (K) and is presented in column (L).

- o Net Benefit

  - The advantage (or disadvantage) for an oilshale fueled power project compared to conventional coal or oil fueled plants is the difference between the fuel cost savings and the higher capital plus O&M costs.

  - Cumulative "incremental" capital plus O&M costs are listed in column (N).

  - Cumulative fuel cost savings are listed in column (P).

  - The last column on each table presents the cumulative net benefit based on the criteria listed at the top of each table.

On Figures 8-1, 8-2, 8-3, and 8-4 (at the end of this section), the cumulative net benefits at two imported fuel price levels are plotted against the cumulative incremental cost of capital plus O&M costs to show the payout periods for the greater investment needed for a shale-to-power project.

A summary of the results of this analysis follows.

8.1 OIL SHALE VS. IMPORTED COAL

Oil shale fueled power generation is clearly attractive in Jordan with 80% borrowed capital compared with power generation fueled with imported coal priced above about $55 per tonne assuming that a 5 to 10 year payout is a reasonable business risk. Even at $50 per tonne, fuel costs savings exceed $1.2 billion and net benefits approaching $800 million will favor oil shale over coal after 25 years of operations. At a coal price level of $70 per tonne the net benefit favoring oil shale exceeds $2.5 billion. (See Tables 8-3 and 8-4 and Figure 8-2 at the end of this section).

If the project must use 50% equity capital, then imported coal at Aqaba must reach a price above about $60 per tonne to achieve a reasonable payout of incremental investment for shale. The net benefit favoring shale fuel after 25 years operations lies between $315 million at $50/tonne coal and $2.1 billion at $70/tonne (see Tables 8-1 and 8-2 and Figure 8-1)

8.2 OIL SHALE VS. IMPORTED OIL

The comparison against an oil fired power plant is less favorable. With 80% borrowed capital the price of oil must rise to about $22/Bbl ($150/tonne) to obtain a reasonable payout of the incremental investment for oil shale. If oil prices rise to level of $24/Bbl ($170/tonne) by year 2000 as forecast in the recent study by Meta Systems/Hagler-Bailey/Bechtel then the 25 year net benefit vs oil rises to $1.8 billion (see Tables 8-5 and 8-6 and Figure 8-3.)

At current oil price levels of $17/Bbl ($120/tonne) an oilshale project would not compete with an oil-fired power plant even at 80/20 debt/equity financing and is distinctly less attractive with 50/50 financing.

8.3 LEVELIZED COST ANALYSIS

An alternative method of examining power project investments employs the so-called levelized cost analysis. This method uses present worth factors over the 25-year project life to bring all of the previously calculated cost elements to the current day cost base.

Tables 8-9 through 8-16 (at the end of this section) present such an analysis based on EPRI levelized revenue requirement methodology.

This alternate method of analysis has the effect of showing a higher cost for generated power and lower present worth of net benefits:

Fuel	EPRI Year-by-Year Revenue Method Power Cost - Mills/KWH Debt/Equity 80/20	Debt/Equity 50/50	EPRI Levelized Revenue Method Power Cost - Mills/KWH Debt/Equity 80/20	Debt/Equity 50/50
Oil Shale	71	78	83	90
$50 Coal	68	71	88	89
$70 Coal	78	82	107	107
$120 Oil	56	58	76	76
$170 Oil	67	70	96	96

8.4 CRUDE OIL PRICE TRENDS

In considering these alternative fuel comparisons, one must realize that a commercial scale oil shale to power project could not start before 1995, at the earliest. Hence a 25 year operating period extends to year 2020. While it is difficult to forecast future oil and coal prices with any precision, it is reasonably certain that both will go up significantly from present depressed levels. Figure 8-5 shows the Chevron Corporation forecast for future crude oil price trends. (Excerpts from the October 1987 Chevron Corporation report entitled: World Energy Outlook are presented in Appendix 12.)

Planning the future oil shale venture around $20/Bbl oil and/or $55/tonne coal is not unreasonable.

It is concluded from these studies that an oil shale to power project likely will be economically viable in Jordan in the years 1995-2020 time frame considered here.

While the economic analysis prepared in this study is somewhat arbitraily based on a 400 MW size project, the forecasted future power demand growth may require two such projects at Sultani. Future planning and definitive studies should consider this option.

Recovery of the underlying phosphate deposit after removal of the overburden and oil shale materials was specifically excluded from this prefeasibility study, however such by-product credits might enhance the economics for the shale venture. Any follow-on study work should attempt to define these credits.

Another item not dealt with in this prefeasibility study is the effect of an oilshale power project on the Zarqa refinery. The development Jordan's oil shale resources for power plant fuel could result in retirement of existing older power generating facilities. These older less efficient plants burn heavy fuel oil and diesel gas oil supplied by the Zarqa refinery. A shift toward a lighter project structure at Zarqa to reduce manufacture of heavy fuel oil may require addition of a Delayed Coking process plant. The byproduct coke can be consumed as supplemental fuel at the oilshale power plants.

Section 10 following presents the Recommended Action Plan suggested as a result of this Prefeasibility Study. The creation of a specific work plan, schedule and budget for this next step has not been undertaken pending provision of funding for such follow-on work.

Table 8-1

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY 50/50 - $70 COAL ($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760 (POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $70

OILSHALE $/T= $7.76

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.53
-COAL $20.00

		COAL					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) COAL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) COAL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.153	$82.27	$95	$21	$99	$215	$8.23	$116	$25	$64	$205	-25	-25	$35	$35	$10
2	0.148	87.91	92	22	106	220	8.72	112	26	68	206	-24	-49	38	73	24
3	0.144	93.93	89	24	113	226	9.24	109	28	72	209	-24	-73	41	114	41
4	0.139	100.36	86	25	121	232	9.80	106	30	76	212	-24	-97	45	159	62
5	0.135	107.23	83	27	129	239	10.38	102	31	81	214	-24	-121	48	207	86
6	0.130	114.57	81	28	138	247	11.01	99	33	86	218	-23	-144	52	259	115
7	0.125	122.42	78	30	147	255	11.67	95	35	91	221	-22	-166	56	315	149
8	0.121	130.80	75	32	158	265	12.37	92	38	96	226	-23	-189	62	377	188
9	0.116	139.76	72	34	168	274	13.11	89	40	102	231	-23	-212	66	443	231
10	0.112	149.33	69	36	180	285	13.90	85	42	108	235	-22	-234	72	515	281
11	0.107	159.56	67	38	192	297	14.73	82	45	115	242	-22	-256	77	592	336
12	0.103	170.49	64	40	205	309	15.61	78	47	122	247	-21	-277	83	675	398
13	0.098	182.16	61	43	219	323	16.55	75	50	129	254	-22	-299	90	765	466
14	0.094	194.63	58	45	234	337	17.54	71	53	137	261	-21	-320	97	862	542
15	0.089	207.96	55	48	250	353	18.60	68	56	145	269	-21	-341	105	967	626
16	0.085	222.20	53	51	268	372	19.71	65	60	153	278	-21	-362	115	1082	720
17	0.080	237.42	50	54	286	390	20.90	61	63	163	287	-21	-383	123	1205	822
18	0.076	253.68	47	57	306	410	22.15	58	67	172	297	-21	-404	134	1339	935
19	0.071	271.05	44	61	326	431	23.48	54	71	183	308	-21	-424	143	1482	1,058
20	0.067	289.61	42	64	349	455	24.89	51	75	194	320	-20	-445	155	1637	1,192
21	0.062	309.45	39	68	373	480	26.38	47	80	205	332	-20	-465	168	1805	1,340
22	0.058	330.64	36	72	398	506	27.96	44	85	218	347	-21	-485	180	1985	1,500
23	0.053	353.28	33	76	426	535	29.64	41	90	231	362	-21	-507	195	2180	1,673
24	0.049	377.47	30	81	455	566	31.42	37	95	245	377	-21	-528	210	2390	1,862
25	0.044	403.32	28	86	486	600	33.30	34	101	259	394	-21	-549	227	2617	2,068

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$95	$21	$99	$215	$116	$25	$64	$205
COST - MILLS/KWh	36	8	38	82	44	9	24	78

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-2

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY

50/50 - $50 COAL

($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $50
OILSHALE $/T= $7.76

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.53
-COAL $20.00

		COAL					OIL SHALE PLANT					INCREMENTAL CAPITAL+O&M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) COAL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) COAL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.153	$58.77	$95	$21	$71	$187	$8.23	$116	$25	$64	$205	-25	-25	$7	$7	($18)
2	0.148	62.79	92	22	76	190	8.72	112	26	68	206	-24	-49	8	15	(34)
3	0.144	67.09	89	24	81	194	9.24	109	28	72	209	-24	-73	9	24	(49)
4	0.139	71.68	86	25	86	197	9.80	106	30	76	212	-24	-97	10	34	(63)
5	0.135	76.59	83	27	92	202	10.38	102	31	81	214	-24	-121	11	45	(76)
6	0.130	81.84	81	28	99	208	11.01	99	33	86	218	-23	-144	13	58	(86)
7	0.125	87.44	78	30	105	213	11.67	95	35	91	221	-22	-166	14	72	(94)
8	0.121	93.43	75	32	113	220	12.37	92	38	96	226	-23	-189	17	89	(100)
9	0.116	99.83	72	34	120	226	13.11	89	40	102	231	-23	-212	18	107	(105)
10	0.112	106.67	69	36	128	233	13.90	85	42	108	235	-22	-234	20	127	(107)
11	0.107	113.97	67	38	137	242	14.73	82	45	115	242	-22	-256	22	149	(107)
12	0.103	121.78	64	40	147	251	15.61	78	47	122	247	-21	-277	25	174	(103)
13	0.098	130.11	61	43	157	261	16.55	75	50	129	254	-22	-299	28	202	(97)
14	0.094	139.02	58	45	167	270	17.54	71	53	137	261	-21	-320	30	232	(88)
15	0.089	148.55	55	48	179	282	18.60	68	56	145	269	-21	-341	34	266	(75)
16	0.085	158.72	53	51	191	295	19.71	65	60	153	278	-21	-362	38	304	(58)
17	0.080	169.59	50	54	204	308	20.90	61	63	163	287	-21	-383	41	345	(38)
18	0.076	181.20	47	57	218	322	22.15	58	67	172	297	-21	-404	46	391	(13)
19	0.071	193.61	44	61	233	338	23.48	54	71	183	308	-21	-424	50	441	17
20	0.067	206.87	42	64	249	355	24.89	51	75	194	320	-20	-445	55	496	51
21	0.062	221.03	39	68	266	373	26.38	47	80	205	332	-20	-465	61	557	92
22	0.058	236.17	36	72	284	392	27.96	44	85	218	347	-21	-485	66	623	138
23	0.053	252.34	33	76	304	413	29.64	41	90	231	362	-21	-507	73	696	189
24	0.049	269.62	30	81	325	436	31.42	37	95	245	377	-21	-528	80	776	248
25	0.044	288.09	28	86	347	461	33.30	34	101	259	394	-21	-549	88	864	315

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$95	$21	$71	$187	$116	$25	$64	$205
COST - MILLS/KWh	36	8	27	71	44	9	24	78

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-3

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY

80/20 - $70 COAL

($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.50% ANNUALLY

COAL COST$/T = $70
OILSHALE $/T= $6.84

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-COAL $20.00

		COAL					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) COAL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) COAL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.139	$82.27	$86	$21	$99	$206	$7.25	$106	$25	$56	$187	-23	-23	$43	$43	$20
2	0.135	87.91	84	22	106	212	7.69	103	26	60	189	-23	-46	46	89	43
3	0.131	93.93	81	24	113	218	8.15	100	28	63	191	-23	-69	50	139	70
4	0.127	100.36	79	25	121	225	8.64	97	29	67	193	-22	-91	54	193	102
5	0.123	107.23	76	27	129	232	9.15	94	31	71	196	-22	-113	58	251	138
6	0.119	114.57	74	28	138	240	9.70	91	33	76	200	-21	-134	62	313	179
7	0.115	122.42	71	30	147	248	10.28	88	35	80	203	-22	-156	67	380	224
8	0.111	130.80	69	32	158	259	10.90	85	37	85	207	-21	-177	73	453	276
9	0.107	139.76	67	34	168	269	11.56	82	39	90	211	-20	-197	78	531	334
10	0.103	149.33	64	36	180	280	12.25	79	41	95	215	-21	-218	85	616	398
11	0.099	159.56	62	38	192	292	12.98	76	44	101	221	-20	-238	91	707	469
12	0.095	170.49	59	40	205	304	13.76	73	47	107	227	-20	-259	98	805	546
13	0.091	182.16	57	43	219	319	14.59	70	49	114	233	-20	-278	105	910	632
14	0.088	194.63	54	45	234	333	15.46	67	52	120	239	-20	-298	114	1024	726
15	0.084	207.96	52	48	250	350	16.39	64	56	128	248	-20	-318	122	1146	828
16	0.080	222.20	49	51	268	368	17.38	60	59	135	254	-19	-337	133	1279	942
17	0.076	237.42	47	54	286	387	18.42	57	62	143	262	-19	-356	143	1422	1,066
18	0.072	253.68	44	57	306	407	19.52	54	66	152	272	-19	-375	154	1576	1,201
19	0.068	271.05	42	61	326	429	20.70	51	70	161	282	-19	-393	165	1741	1,348
20	0.064	289.61	40	64	349	453	21.94	48	74	171	293	-18	-411	178	1919	1,508
21	0.060	309.45	37	68	373	478	23.25	45	79	181	305	-19	-430	192	2111	1,681
22	0.056	330.64	35	72	398	505	24.65	42	83	192	317	-18	-448	206	2317	1,869
23	0.052	353.28	32	76	426	534	26.13	39	88	203	330	-19	-467	223	2540	2,073
24	0.048	377.47	30	81	455	566	27.69	36	94	216	346	-19	-486	239	2779	2,293
25	0.044	403.32	27	86	486	599	29.36	33	99	228	360	-20	-506	258	3037	2,531

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$86	$21	$99	$206	$106	$25	$56	$187
COST - MILLS/KWh	33	8	38	78	40	9	21	71

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-4

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY 80/20 - $50 COAL ($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760 (POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $50

OILSHALE $/T= $6.84

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-COAL $20.00

		COAL					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) COAL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) COAL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.139	$58.77	$86	$21	$71	$178	$7.25	$106	$25	$56	$187	-23	-23	$15	$15	($8)
2	0.135	62.79	84	22	76	182	7.69	103	26	60	189	-23	-46	16	31	(15)
3	0.131	67.09	81	24	81	186	8.15	100	28	63	191	-23	-69	18	49	(20)
4	0.127	71.68	79	25	86	190	8.64	97	29	67	193	-22	-91	19	68	(23)
5	0.123	76.59	76	27	92	195	9.15	94	31	71	196	-22	-113	21	89	(24)
6	0.119	81.84	74	28	99	201	9.70	91	33	76	200	-21	-134	23	112	(22)
7	0.115	87.44	71	30	105	206	10.28	88	35	80	203	-22	-156	25	137	(19)
8	0.111	93.43	69	32	113	214	10.90	85	37	85	207	-21	-177	28	165	(12)
9	0.107	99.83	67	34	120	221	11.56	82	39	90	211	-20	-197	30	195	(2)
10	0.103	106.67	64	36	128	228	12.25	79	41	95	215	-21	-218	33	228	10
11	0.099	113.97	62	38	137	237	12.98	76	44	101	221	-20	-238	36	264	26
12	0.095	121.78	59	40	147	246	13.76	73	47	107	227	-20	-259	40	304	45
13	0.091	130.11	57	43	157	257	14.59	70	49	114	233	-20	-278	43	347	69
14	0.088	139.02	54	45	167	266	15.46	67	52	120	239	-20	-298	47	394	96
15	0.084	148.55	52	48	179	279	16.39	64	56	128	248	-20	-318	51	445	127
16	0.080	158.72	49	51	191	291	17.38	60	59	135	254	-19	-337	56	501	164
17	0.076	169.59	47	54	204	305	18.42	57	62	143	262	-19	-356	61	562	206
18	0.072	181.20	44	57	218	319	19.52	54	66	152	272	-19	-375	66	628	253
19	0.068	193.61	42	61	233	336	20.70	51	70	161	282	-19	-393	72	700	307
20	0.064	206.87	40	64	249	353	21.94	48	74	171	293	-18	-411	78	778	367
21	0.060	221.03	37	68	266	371	23.25	45	79	181	305	-19	-430	85	863	433
22	0.056	236.17	35	72	284	391	24.65	42	83	192	317	-18	-448	92	955	507
23	0.052	252.34	32	76	304	412	26.13	39	88	203	330	-19	-467	101	1056	589
24	0.048	269.62	30	81	325	436	27.69	36	94	216	346	-19	-486	109	1165	679
25	0.044	288.09	27	86	347	460	29.36	33	99	228	360	-20	-506	119	1284	778

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$86	$21	$71	$178	$106	$25	$56	$187
COST - MILLS/KWh	33	8	27	68	40	9	21	71

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-5

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY

80/20 - $170 OIL

($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $170
OILSHALE $/T= $6.84

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-OIL $13.00

		OIL PLANT					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) OIL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) OIL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.139	$199.81	$62	$14	$101	$177	$7.25	$106	$25	$56	$187	-55	-55	$45	$45	($10)
2	0.135	213.49	60	15	107	182	7.69	103	26	60	189	-54	-109	47	92	(17)
3	0.131	228.11	58	15	115	188	8.15	100	28	63	191	-54	-163	52	144	(19)
4	0.127	243.73	56	16	123	195	8.64	97	29	67	193	-54	-217	56	200	(17)
5	0.123	260.42	55	17	131	203	9.15	94	31	71	196	-53	-270	60	260	(10)
6	0.119	278.25	53	18	140	211	9.70	91	33	76	200	-52	-322	64	324	2
7	0.115	297.31	51	20	150	221	10.28	88	35	80	203	-52	-374	70	394	20
8	0.111	317.67	49	21	160	230	10.90	85	37	85	207	-52	-427	75	469	42
9	0.107	339.42	48	22	171	241	11.56	82	39	90	211	-51	-478	81	550	72
10	0.103	362.66	46	23	182	251	12.25	79	41	95	215	-51	-529	87	637	108
11	0.099	387.50	44	25	195	264	12.98	76	44	101	221	-51	-580	94	731	151
12	0.095	414.04	42	26	208	276	13.76	73	47	107	227	-51	-632	101	832	200
13	0.091	442.39	41	28	223	292	14.59	70	49	114	233	-51	-682	109	941	259
14	0.088	472.68	39	29	238	306	15.46	67	52	120	239	-51	-733	118	1059	326
15	0.084	505.05	37	31	254	322	16.39	64	56	128	248	-51	-785	126	1185	400
16	0.080	539.64	35	33	271	339	17.38	60	59	135	254	-51	-835	136	1321	486
17	0.076	576.59	34	35	290	359	18.42	57	62	143	262	-50	-886	147	1468	582
18	0.072	616.08	32	37	310	379	19.52	54	66	152	272	-51	-937	158	1626	689
19	0.068	658.27	30	39	331	400	20.70	51	70	161	282	-52	-989	170	1796	807
20	0.064	703.35	28	42	354	424	21.94	48	74	171	293	-53	-1041	183	1979	938
21	0.060	751.51	26	44	378	448	23.25	45	79	181	305	-54	-1095	197	2176	1,081
22	0.056	802.98	25	47	404	476	24.65	42	83	192	317	-54	-1148	212	2388	1,240
23	0.052	857.96	23	50	432	505	26.13	39	88	203	330	-55	-1203	229	2617	1,414
24	0.048	916.72	21	53	461	535	27.69	36	94	216	346	-56	-1259	245	2862	1,603
25	0.044	979.49	19	56	493	568	29.36	33	99	228	360	-58	-1317	265	3127	1,810

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$62	$14	$101	$177	$106	$25	$56	$187
COST - MILLS/KWh	24	5	38	67	40	9	21	71

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-6

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY 80/20 - $120 OIL ($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760 (POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $120

OILSHALE $/T= $6.84

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-OIL $13.00

		OIL PLANT					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) OIL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) OIL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.139	$141.04	$62	$14	$71	$147	$7.25	$106	$25	$56	$187	-55	-55	$15	$15	($40)
2	0.135	150.70	60	15	76	151	7.69	103	26	60	189	-54	-109	16	31	(78)
3	0.131	161.02	58	15	81	154	8.15	100	28	63	191	-54	-163	18	49	(114)
4	0.127	172.04	56	16	87	159	8.64	97	29	67	193	-54	-217	20	69	(148)
5	0.123	183.83	55	17	92	164	9.15	94	31	71	196	-53	-270	21	90	(180)
6	0.119	196.41	53	18	99	170	9.70	91	33	76	200	-52	-322	23	113	(209)
7	0.115	209.86	51	20	106	177	10.28	88	35	80	203	-52	-374	26	139	(235)
8	0.111	224.24	49	21	113	183	10.90	85	37	85	207	-52	-427	28	167	(260)
9	0.107	239.59	48	22	121	191	11.56	82	39	90	211	-51	-478	31	198	(280)
10	0.103	256.00	46	23	129	198	12.25	79	41	95	215	-51	-529	34	232	(297)
11	0.099	273.53	44	25	138	207	12.98	76	44	101	221	-51	-580	37	269	(311)
12	0.095	292.26	42	26	147	215	13.76	73	47	107	227	-51	-632	40	309	(323)
13	0.091	312.27	41	28	157	226	14.59	70	49	114	233	-51	-682	43	352	(330)
14	0.088	333.66	39	29	168	236	15.46	67	52	120	239	-51	-733	48	400	(333)
15	0.084	356.51	37	31	179	247	16.39	64	56	128	248	-51	-785	51	451	(334)
16	0.080	380.92	35	33	192	260	17.38	60	59	135	254	-51	-835	57	508	(327)
17	0.076	407.01	34	35	205	274	18.42	57	62	143	262	-50	-886	62	570	(316)
18	0.072	434.88	32	37	219	288	19.52	54	66	152	272	-51	-937	67	637	(300)
19	0.068	464.66	30	39	234	303	20.70	51	70	161	282	-52	-989	73	710	(279)
20	0.064	496.48	28	42	250	320	21.94	48	74	171	293	-53	-1041	79	789	(252)
21	0.060	530.48	26	44	267	337	23.25	45	79	181	305	-54	-1095	86	875	(220)
22	0.056	566.81	25	47	285	357	24.65	42	83	192	317	-54	-1148	93	968	(180)
23	0.052	605.62	23	50	305	378	26.13	39	88	203	330	-55	-1203	102	1070	(133)
24	0.048	647.09	21	53	325	399	27.69	36	94	216	346	-56	-1259	109	1179	(80)
25	0.044	691.41	19	56	348	423	29.36	33	99	228	360	-58	-1317	120	1299	(18)

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$62	$14	$71	$147	$106	$25	$56	$187
COST - MILLS/KWh	24	5	27	56	40	9	21	71

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-7

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT
BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY
50/50 - $170 OIL
($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $170
OILSHALE $/T= $7.76

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.56
-OIL $13.00

		OIL PLANT					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) OIL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) OIL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.153	$199.81	$68	$14	$101	$183	$8.23	$116	$25	$64	$205	-59	-59	$37	$37	($22)
2	0.148	213.49	66	15	107	188	8.72	112	26	68	206	-58	-117	39	76	(41)
3	0.144	228.11	64	15	115	194	9.24	109	28	72	209	-58	-175	43	119	(56)
4	0.139	243.73	62	16	123	201	9.80	106	30	76	212	-57	-232	47	166	(66)
5	0.135	260.42	60	17	131	208	10.38	102	32	81	215	-56	-288	50	216	(72)
6	0.130	278.25	58	18	140	216	11.01	99	33	86	218	-56	-344	54	270	(74)
7	0.125	297.31	56	20	150	226	11.67	95	35	91	221	-55	-399	59	329	(70)
8	0.121	317.67	54	21	160	235	12.37	92	38	96	226	-55	-454	64	393	(61)
9	0.116	339.42	52	22	171	245	13.11	89	40	102	231	-55	-509	69	462	(47)
10	0.112	362.66	50	23	182	255	13.90	85	42	108	235	-54	-563	74	536	(27)
11	0.107	387.50	48	25	195	268	14.73	82	45	115	242	-54	-617	80	616	(1)
12	0.103	414.04	46	26	208	280	15.61	78	47	122	247	-53	-670	86	702	32
13	0.098	442.39	44	28	223	295	16.55	75	50	129	254	-54	-723	94	796	73
14	0.094	472.68	42	29	238	309	17.54	71	53	137	261	-53	-776	101	897	121
15	0.089	505.05	40	31	254	325	18.60	68	56	145	269	-53	-830	109	1006	176
16	0.085	539.64	38	33	271	342	19.71	65	60	153	278	-54	-883	118	1124	241
17	0.080	576.59	36	35	290	361	20.90	61	63	163	287	-53	-937	127	1251	314
18	0.076	616.08	34	37	310	381	22.15	58	67	172	297	-54	-991	138	1389	398
19	0.071	658.27	32	39	331	402	23.48	54	71	183	308	-54	-1045	148	1537	492
20	0.067	703.35	30	42	354	426	24.89	51	76	194	321	-55	-1100	160	1697	597
21	0.062	751.51	28	44	378	450	26.38	47	80	205	332	-55	-1155	173	1870	715
22	0.058	802.98	26	47	404	477	27.96	44	85	218	347	-56	-1211	186	2056	845
23	0.053	857.96	24	50	432	506	29.64	41	90	231	362	-57	-1268	201	2257	989
24	0.049	916.72	22	53	461	536	31.42	37	95	245	377	-58	-1326	216	2473	1,147
25	0.044	979.49	20	56	493	569	33.30	34	101	259	394	-59	-1385	234	2707	1,322

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$68	$14	$101	$183	$116	$25	$64	$205
COST - MILLS/KWh	26	5	38	70	44	10	24	78

NOTE :
COLUMN -M=D+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-8

CUMULATIVE NET BENEFITS FOR 400 MW COAL VS OIL SHALE PLANT BASED ON EPRI YEAR-BY-YEAR REVENUE REQUIREMENT METHODOLOGY 50/50 - $120 OIL ($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760 (POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $120

OILSHALE $/T= $7.76

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.56
-OIL $13.00

		OIL PLANT					OIL SHALE PLANT					INCREMENTAL CAPITAL+O &M		FUEL SAVING		
(A) YR	(B) CAPITAL FAC-TOR	(C) OIL COST $/TN	(D) CAPITAL COST	(E) O&M COST	(F) OIL COST	(G) TOTAL REVENUE PER YR	(H) O/SHALE COST $/TN	(I) CAPITAL COST	(J) O&M COST	(K) O/SHALE COST	(L) TOTAL REVENUE PER YR	(M) INCRE-MENT PER/YR	(N) CUMU-LATIVE.	(O) SAVING/ YR	(P) CUMU-LATIVE	(Q) NET BENEFIT
1	0.153	$141.04	$68	$14	$71	$153	$8.23	$116	$25	$64	$205	-59	-59	$7	$7	($52)
2	0.148	150.70	66	15	76	157	8.72	112	26	68	206	-58	-117	8	15	(102)
3	0.144	161.02	64	15	81	160	9.24	109	28	72	209	-58	-175	9	24	(151)
4	0.139	172.04	62	16	87	165	9.80	106	30	76	212	-57	-232	11	35	(197)
5	0.135	183.83	60	17	92	169	10.38	102	32	81	215	-56	-288	11	46	(242)
6	0.130	196.41	58	18	99	175	11.01	99	33	86	218	-56	-344	13	59	(285)
7	0.125	209.86	56	20	106	182	11.67	95	35	91	221	-55	-399	15	74	(325)
8	0.121	224.24	54	21	113	188	12.37	92	38	96	226	-55	-454	17	91	(363)
9	0.116	239.59	52	22	121	195	13.11	89	40	102	231	-55	-509	19	110	(399)
10	0.112	256.00	50	23	129	202	13.90	85	42	108	235	-54	-563	21	131	(432)
11	0.107	273.53	48	25	138	211	14.73	82	45	115	242	-54	-617	23	154	(463)
12	0.103	292.26	46	26	147	219	15.61	78	47	122	247	-53	-670	25	179	(491)
13	0.098	312.27	44	28	157	229	16.55	75	50	129	254	-54	-723	28	207	(516)
14	0.094	333.66	42	29	168	239	17.54	71	53	137	261	-53	-776	31	238	(538)
15	0.089	356.51	40	31	179	250	18.60	68	56	145	269	-53	-830	34	272	(558)
16	0.085	380.92	38	33	192	263	19.71	65	60	153	278	-54	-883	39	311	(572)
17	0.080	407.01	36	35	205	276	20.90	61	63	163	287	-53	-937	42	353	(584)
18	0.076	434.88	34	37	219	290	22.15	58	67	172	297	-54	-991	47	400	(591)
19	0.071	464.66	32	39	234	305	23.48	54	71	183	308	-54	-1045	51	451	(594)
20	0.067	496.48	30	42	250	322	24.89	51	76	194	321	-55	-1100	56	507	(593)
21	0.062	530.48	28	44	267	339	26.38	47	80	205	332	-55	-1155	62	569	(586)
22	0.058	566.81	26	47	285	358	27.96	44	85	218	347	-56	-1211	67	636	(575)
23	0.053	605.62	24	50	305	379	29.64	41	90	231	362	-57	-1268	74	710	(558)
24	0.049	647.09	22	53	325	400	31.42	37	95	245	377	-58	-1326	80	790	(536)
25	0.044	691.41	20	56	348	424	33.30	34	101	259	394	-59	-1385	89	879	(506)

1st YEAR COST : FROM YEAR ONE ABOVE

REVENUE REQUIRED -$/YR	$68	$14	$71	$153	$116	$25	$64	$205
COST - MILLS/KWh	26	5	27	58	44	10	24	78

NOTE :
COLUMN -M=O+E-I-J
O=F-K
Q=P-N

PD:2261f

Table 8-9

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
50/50 - $70 COAL
($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $70
OILSHALE $/T $7.76

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.53
-COAL $20.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.1) TO PRESENT DAY :

YEAR	PRESENT WORTH FACTORS	ANNUITY FACTORS	COAL PLANT CAPITAL COST	COAL PLANT O&M COST	COAL PLANT COAL COST	COAL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.899	0.899	85	19	89	193	104	22	58	184	9
2	0.808	1.707	74	18	86	178	90	21	55	167	11
3	0.726	2.433	65	17	82	164	79	20	52	152	12
4	0.653	3.086	56	16	79	152	69	19	50	138	13
5	0.587	3.673	49	16	76	140	60	18	48	126	14
6	0.527	4.200	43	15	73	130	52	18	45	115	15
7	0.474	4.674	37	14	70	121	45	17	43	105	16
8	0.426	5.101	32	14	67	113	39	16	41	96	17
9	0.383	5.484	28	13	64	105	34	15	39	88	16
10	0.344	5.828	24	12	62	98	29	15	37	81	17
11	0.310	6.138	21	12	59	92	25	14	36	75	17
12	0.278	6.416	18	11	57	86	22	13	34	69	17
13	0.250	6.666	15	11	55	81	19	13	32	64	17
14	0.225	6.891	13	10	53	76	16	12	31	59	17
15	0.202	7.093	11	10	51	71	14	11	29	54	17
16	0.182	7.274	10	9	49	68	12	11	28	50	17
17	0.163	7.438	8	9	47	64	10	10	27	47	17
18	0.147	7.584	7	8	45	60	9	10	25	44	17
19	0.132	7.716	6	8	43	57	7	9	24	41	16
20	0.119	7.835	5	8	41	54	6	9	23	38	16
21	0.107	7.941	4	7	40	51	5	9	22	35	16
22	0.096	8.037	3	7	38	48	4	8	21	33	15
23	0.086	8.123	3	7	37	46	4	8	20	31	15
24	0.077	8.201	2	6	35	44	3	7	19	29	15
25	0.070	8.270	2	6	34	42	2	7	18	27	14
TOTAL PRESENT WORTH VALUE:			$620	$283	$1,430	$2,334	$760	$333	$856	$1,949	$385
LEVELIZED REVENUE REQUIRED -$/YR			$75	$34	$173	$282	$92	$40	$103	$236	
LEVELIZED COST- MILLS/KWh			29	13	66	107	35	15	39	90	

PD:2261f

Table 8-10

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
50/50 - $50 COAL
($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $50
OILSHALE $/T $7.76

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
=========
-OILSHALE$23.53
-COAL $20.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.2) TO PRESENT DAY :

YEAR	PRESENT WORTH FACTORS	ANNUITY FACTORS	COAL PLANT CAPITAL COST	COAL PLANT O&M COST	COAL PLANT COAL COST	COAL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.899	0.899	85	19	64	168	104	22	58	184	(16)
2	0.808	1.707	74	18	61	154	90	21	55	167	(13)
3	0.726	2.433	65	17	59	141	79	20	52	152	(11)
4	0.653	3.086	56	16	56	129	69	19	50	138	(9)
5	0.587	3.673	49	16	54	118	60	18	48	126	(7)
6	0.527	4.200	43	15	52	110	52	18	45	115	(5)
7	0.474	4.674	37	14	50	101	45	17	43	105	(4)
8	0.426	5.101	32	14	48	94	39	16	41	96	(2)
9	0.383	5.484	28	13	46	86	34	15	39	88	(2)
10	0.344	5.828	24	12	44	80	29	15	37	81	(1)
11	0.310	6.138	21	12	42	75	25	14	36	75	0
12	0.278	6.416	18	11	41	70	22	13	34	69	1
13	0.250	6.666	15	11	39	65	19	13	32	64	2
14	0.225	6.891	13	10	38	61	16	12	31	59	2
15	0.202	7.093	11	10	36	57	14	11	29	54	3
16	0.182	7.274	10	9	35	54	12	11	28	50	3
17	0.163	7.438	8	9	33	50	10	10	27	47	3
18	0.147	7.584	7	8	32	47	9	10	25	44	4
19	0.132	7.716	6	8	31	45	7	9	24	41	4
20	0.119	7.835	5	8	30	42	6	9	23	38	4
21	0.107	7.941	4	7	28	40	5	9	22	35	4
22	0.096	8.037	3	7	27	38	4	8	21	33	4
23	0.086	8.123	3	7	26	36	4	8	20	31	4
24	0.077	8.201	2	6	25	34	3	7	19	29	5
25	0.070	8.270	2	6	24	32	2	7	18	27	5
TOTAL PRESENT WORTH VALUE:			$620	$283	$1,022	$1,926	$760	$333	$856	$1,949	($23)
LEVELIZED REVENUE REQUIRED -$/YR			$75	$34	$124	$233	$92	$40	$103	$236	
LEVELIZED COST- MILLS/KWh			29	13	47	89	35	15	39	90	

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Table 8-11

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY 80/20 - $70 COAL ($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

COAL COST$/T = $70
OILSHALE $/T $6.84

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-COAL $20.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.3) TO PRESENT DAY :

YEAR	PRESENT WORTH FAC-TORS	ANNUITY FACTORS	COAL PLANT CAPITAL COST	COAL PLANT O&M COST	COAL PLANT COAL COST	COAL PLANT TOTAL REVENUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.910	0.910	78	19	90	188	96	22	51	170	18
2	0.828	1.738	70	19	88	176	85	22	50	157	19
3	0.753	2.491	61	18	85	164	75	21	47	144	21
4	0.686	3.177	54	17	83	154	66	20	46	132	22
5	0.624	3.800	47	17	80	145	59	19	44	122	22
6	0.568	4.368	42	16	78	136	52	19	43	113	23
7	0.516	4.884	37	16	76	128	45	18	41	105	23
8	0.470	5.354	32	15	74	122	40	17	40	97	24
9	0.428	5.782	29	14	72	115	35	17	38	90	25
10	0.389	6.171	25	14	70	109	31	16	37	84	25
11	0.354	6.525	22	13	68	103	27	16	36	78	25
12	0.322	6.847	19	13	66	98	24	15	34	73	25
13	0.293	7.140	17	13	64	93	21	14	33	68	25
14	0.267	7.407	14	12	62	89	18	14	32	64	25
15	0.243	7.650	13	12	61	85	16	13	31	60	25
16	0.221	7.871	11	11	59	81	13	13	30	56	25
17	0.201	8.071	9	11	57	78	11	13	29	53	25
18	0.183	8.254	8	10	56	74	10	12	28	50	25
19	0.166	8.421	7	10	54	71	8	12	27	47	24
20	0.151	8.572	6	10	53	69	7	11	26	44	24
21	0.138	8.710	5	9	51	66	6	11	25	42	24
22	0.125	8.835	4	9	50	63	5	10	24	40	24
23	0.114	8.949	4	9	49	61	4	10	23	38	23
24	0.104	9.053	3	8	47	59	4	10	22	36	23
25	0.094	9.147	3	8	46	57	3	9	22	34	23
TOTAL PRESENT WORTH VALUE:			$620	$323	$1,641	$2,584	$762	$374	$860	$1,997	$587
LEVELIZED REVENUE REQUIRED -$/YR			$68	$35	$179	$282	$83	$41	$94	$218	
LEVELIZED COST- MILLS/KWh			26	13	68	107	32	16	36	83	

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Table 8-12

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
80/20 - $50 COAL
($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -COAL $620

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL COAL 1000TN/YR 1,205

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL COAL ESCALATION= 0.80% ANNUALLY

CO[illegible]OST$/T = $50
O[illegible]E $/T $6.84

INTEREST RATE FOR COAL 10% (BORROWED COST)

O&M COST -1ST YEAR
=========
-OILSHALE$23.16
-COAL $20.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.4) TO PRESENT DAY :

YEAR	PRESENT WORTH FAC-TORS	ANNUITY FACTORS	COAL PLANT CAPITAL COST	COAL PLANT O&M COST	COAL PLANT COAL COST	COAL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.910	0.910	78	19	65	162	96	22	51	170	(8)
2	0.828	1.738	70	19	63	151	85	22	50	157	(5)
3	0.753	2.491	61	18	61	140	75	21	47	144	(4)
4	0.686	3.177	54	17	59	130	66	20	46	132	(2)
5	0.624	3.800	47	17	57	121	59	19	44	122	(1)
6	0.568	4.368	42	16	56	114	52	19	43	113	1
7	0.516	4.884	37	16	54	106	45	18	41	105	2
8	0.470	5.354	32	15	53	101	40	17	40	97	3
9	0.428	5.782	29	14	51	94	35	17	38	90	4
10	0.389	6.171	25	14	50	89	31	16	37	84	5
11	0.354	6.525	22	13	49	84	27	16	36	78	6
12	0.322	6.847	19	13	47	79	24	15	34	73	6
13	0.293	7.140	17	13	46	75	21	14	33	68	7
14	0.267	7.407	14	12	45	71	18	14	32	64	7
15	0.243	7.650	13	12	43	68	16	13	31	60	8
16	0.221	7.871	11	11	42	64	13	13	30	56	8
17	0.201	8.071	9	11	41	61	11	13	29	53	9
18	0.183	8.254	8	10	40	58	10	12	28	50	9
19	0.166	8.421	7	10	39	56	8	12	27	47	9
20	0.151	8.572	6	10	38	53	7	11	26	44	9
21	0.138	8.710	5	9	37	51	6	11	25	42	9
22	0.125	8.835	4	9	36	49	5	10	24	40	9
23	0.114	8.949	4	9	35	47	4	10	23	38	9
24	0.104	9.053	3	8	34	45	4	10	22	36	9
25	0.094	9.147	3	8	33	43	3	9	22	34	9
TOTAL PRESENT WORTH VALUE:			$620	$323	$1,172	$2,115	$762	$374	$860	$1,997	$119
LEVELIZED REVENUE REQUIRED -$/YR			$68	$35	$128	$231	$83	$41	$94	$218	
LEVELIZED COST- MILLS/KWh			26	13	49	88	32	16	36	83	

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Table 8-13

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY 80/20 - $170 OIL ($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760 (POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $170

OILSHALE $/T= $6.84

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-OIL $13.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.5) TO PRESENT DAY :

YEAR	PRESENT WORTH FAC-TORS	ANNUITY FACTORS	OIL PLANT CAPITAL COST	OIL PLANT O&M COST	OIL PLANT OIL COST	OIL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.910	0.910	56	13	92	161	96	22	51	170	(9)
2	0.828	1.738	50	12	89	150	85	22	50	157	(6)
3	0.753	2.491	44	12	87	142	75	21	47	144	(2)
4	0.686	3.177	38	11	84	134	66	20	46	132	1
5	0.624	3.800	34	11	82	127	59	19	44	122	5
6	0.568	4.368	30	10	79	120	52	19	43	113	7
7	0.516	4.884	26	10	77	114	45	18	41	105	9
8	0.470	5.354	23	10	75	108	40	17	40	97	11
9	0.428	5.782	21	9	73	103	35	17	38	90	13
10	0.389	6.171	18	9	71	98	31	16	37	84	14
11	0.354	6.525	16	9	69	93	27	16	36	78	15
12	0.322	6.847	14	8	67	89	24	15	34	73	16
13	0.293	7.140	12	8	65	86	21	14	33	68	17
14	0.267	7.407	10	8	63	82	18	14	32	64	18
15	0.243	7.650	9	8	62	78	16	13	31	60	18
16	0.221	7.871	8	7	60	75	13	13	30	56	19
17	0.201	8.071	7	7	58	72	11	13	29	53	19
18	0.183	8.254	6	7	57	69	10	12	28	50	20
19	0.166	8.421	5	7	55	67	8	12	27	47	20
20	0.151	8.572	4	6	54	64	7	11	26	44	20
21	0.138	8.710	4	6	52	62	6	11	25	42	20
22	0.125	8.835	3	6	51	60	5	10	24	40	20
23	0.114	8.949	3	6	49	58	4	10	23	38	20
24	0.104	9.053	2	5	48	55	4	10	22	36	20
25	0.094	9.147	2	5	47	54	3	9	22	34	20
TOTAL PRESENT WORTH VALUE:			$444	$210	$1,635	$2,319	$762	$374	$860	$1,997	$323
LEVELIZED REVENUE REQUIRED -$/YR			$49	$23	$182	$254	$83	$41	$94	$218	
LEVELIZED COST- MILLS/KWh			18	9	69	96	32	16	36	83	

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Table 8-14

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
80/20 - $120 OIL
($ Millions)

DEBT RATIO : 80%

EQUITY RATIO : 20%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $120
OILSHALE $/T= $6.84

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.16
-OIL $13.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.6) TO PRESENT DAY :

YEAR	PRESENT WORTH FACTORS	ANNUITY FACTORS	OIL PLANT CAPITAL COST	OIL PLANT O&M COST	OIL PLANT OIL COST	OIL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.910	0.910	56	13	65	134	96	22	51	170	(36)
2	0.828	1.738	50	12	63	125	85	22	50	157	(32)
3	0.753	2.491	44	12	61	116	75	21	47	144	(27)
4	0.686	3.177	38	11	60	109	66	20	46	132	(23)
5	0.624	3.800	34	11	57	103	59	19	44	122	(20)
6	0.568	4.368	30	10	56	97	52	19	43	113	(17)
7	0.516	4.884	26	10	55	91	45	18	41	105	(14)
8	0.470	5.354	23	10	53	86	40	17	40	97	(11)
9	0.428	5.782	21	9	52	82	35	17	38	90	(9)
10	0.389	6.171	18	9	50	77	31	16	37	84	(7)
11	0.354	6.525	16	9	49	73	27	16	36	78	(5)
12	0.322	6.847	14	8	47	69	24	15	34	73	(4)
13	0.293	7.140	12	8	46	66	21	14	33	68	(2)
14	0.267	7.407	10	8	45	63	18	14	32	64	(1)
15	0.243	7.650	9	8	43	60	16	13	31	60	(0)
16	0.221	7.871	8	7	42	57	13	13	30	56	1
17	0.201	8.071	7	7	41	55	11	13	29	53	2
18	0.183	8.254	6	7	40	53	10	12	28	50	3
19	0.166	8.421	5	7	39	50	8	12	27	47	4
20	0.151	8.572	4	6	38	48	7	11	26	44	4
21	0.138	8.710	4	6	37	46	6	11	25	42	4
22	0.125	8.835	3	6	36	45	5	10	24	40	5
23	0.114	8.949	3	6	35	43	4	10	23	38	5
24	0.104	9.053	2	5	34	41	4	10	22	36	5
25	0.094	9.147	2	5	33	40	3	9	22	34	6
TOTAL PRESENT WORTH VALUE:			$444	$210	$1,176	$1,830	$762	$374	$860	$1,997	($167)
LEVELIZED REVENUE REQUIRED -$/YR			$49	$23	$129	$200	$83	$41	$94	$218	
LEVELIZED COST- MILLS/KWh			18	9	49	76	32	16	36	83	

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Table 8-15

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
50/50 - $170 OIL
($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $170
OILSHALE $/T= $7.76

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
-OILSHALE$23.56
-OIL $13.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.7) TO PRESENT DAY :

YEAR	PRESENT WORTH FAC-TORS	ANNUITY FACTORS	OIL PLANT CAPITAL COST	OIL PLANT O&M COST	OIL PLANT OIL COST	OIL PLANT TOTAL REVEVUE	OIL SHALE PLANT CAPITAL COST	OIL SHALE PLANT O&M COST	OIL SHALE PLANT O/SHALE COST	OIL SHALE PLANT TOTAL REVENUE	NET BENEFIT
1	0.899	0.899	61	12	91	164	104	22	58	184	(20)
2	0.808	1.707	53	12	86	152	90	21	55	167	(15)
3	0.726	2.433	46	11	84	141	79	20	52	152	(11)
4	0.653	3.086	40	11	80	131	69	19	50	138	(7)
5	0.587	3.673	35	10	77	122	60	19	48	126	(4)
6	0.527	4.200	31	10	74	114	52	18	45	115	(1)
7	0.474	4.674	27	9	71	107	45	17	43	105	2
8	0.426	5.101	23	9	68	100	39	16	41	96	4
9	0.383	5.484	20	8	66	94	34	15	39	88	5
10	0.344	5.828	17	8	63	88	29	15	37	81	7
11	0.310	6.138	15	8	60	83	25	14	36	75	8
12	0.278	6.416	13	7	58	78	22	13	34	69	9
13	0.250	6.666	11	7	56	74	19	13	32	64	10
14	0.225	6.891	9	7	54	70	16	12	31	59	11
15	0.202	7.093	8	6	51	66	14	11	29	54	11
16	0.182	7.274	7	6	49	62	12	11	28	50	12
17	0.163	7.438	6	6	47	59	10	10	27	47	12
18	0.147	7.584	5	5	45	56	9	10	25	44	12
19	0.132	7.716	4	5	44	53	7	9	24	41	12
20	0.119	7.835	4	5	42	50	6	9	23	38	12
21	0.107	7.941	3	5	40	48	5	9	22	35	13
22	0.096	8.037	2	4	39	46	4	8	21	33	12
23	0.086	8.123	2	4	37	44	4	8	20	31	12
24	0.077	8.201	2	4	36	41	3	7	19	29	12
25	0.070	8.270	1	4	34	40	2	7	18	27	12
TOTAL PRESENT WORTH VALUE:			$446	$184	$1,452	$2,082	$760	$334	$856	$1,949	$133
LEVELIZED REVENUE REQUIRED -$/YR			$54	$22	$176	$252	$92	$40	$103	$236	
LEVELIZED COST- MILLS/KWh			21	8	67	96	35	15	39	90	

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Table 8-16

400 MW COAL VS OIL SHALE PLANT 25 YEAR LEVELIZED COST
BASED ON EPRI LEVELIZED REVENUE REQUIREMENT METHODOLOGY
50/50 - $120 OIL
($ Millions)

DEBT RATIO : 50%

EQUITY RATIO : 50%

TOTAL INSTALLED COST -OIL $443

TOTAL INSTALLED COST -OILSHALE $760
(POWER PLANT ONLY)

TOTAL OIL 1000TN/YR 503

OIL SHALE 1000TN/YR 7,783

INFLATION RATE = 6.00% ANNUALLY

REAL OIL ESCALATION= 0.80% ANNUALLY

OIL COST$/T = $120
OILSHALE $/T= $7.76

INTEREST RATE FOR OIL = 10% (BORROWED COST)

O&M COST -1ST YEAR
=========
-OILSHALE$25.56
-OIL $13.00

DISCOUNTED ALL REVENUE REQUIRED(FROM TABLE 8.8) TO PRESENT DAY :

			OIL PLANT				OIL SHALE PLANT				
YEAR	PRESENT WORTH FAC-TORS	ANNUITY FACTORS	CAPITAL COST	O&M COST	OIL COST	TOTAL REVEVUE	CAPITAL COST	O&M COST	O/SHALE COST	TOTAL REVENUE	NET BENEFIT
1	0.899	0.899	61	12	64	137	104	22	58	184	(47)
2	0.808	1.707	53	12	61	127	90	21	55	167	(40)
3	0.726	2.433	46	11	59	117	79	20	52	152	(35)
4	0.653	3.086	40	11	57	108	69	19	50	138	(30)
5	0.587	3.673	35	10	54	99	60	19	48	126	(26)
6	0.527	4.200	31	10	52	93	52	18	45	115	(23)
7	0.474	4.674	27	9	50	86	45	17	43	105	(19)
8	0.426	5.101	23	9	48	80	39	16	41	96	(16)
9	0.383	5.484	20	8	46	75	34	15	39	88	(14)
10	0.344	5.828	17	8	44	70	29	15	37	81	(11)
11	0.310	6.138	15	8	43	65	25	14	36	75	(10)
12	0.278	6.416	13	7	41	61	22	13	34	69	(8)
13	0.250	6.666	11	7	39	57	19	13	32	64	(6)
14	0.225	6.891	9	7	38	54	16	12	31	59	(5)
15	0.202	7.093	8	6	36	51	14	11	29	54	(4)
16	0.182	7.274	7	6	35	48	12	11	28	50	(3)
17	0.163	7.438	6	6	33	45	10	10	27	47	(2)
18	0.147	7.584	5	5	32	43	9	10	25	44	(1)
19	0.132	7.716	4	5	31	40	7	9	24	41	(0)
20	0.119	7.835	4	5	30	38	6	9	23	38	0
21	0.107	7.941	3	5	28	36	5	9	22	35	1
22	0.096	8.037	2	4	27	34	4	8	21	33	1
23	0.086	8.123	2	4	26	33	4	8	20	31	1
24	0.077	8.201	2	4	25	31	3	7	19	29	2
25	0.070	8.270	1	4	24	29	2	7	18	27	2
TOTAL PRESENT WORTH VALUE:			$446	$184	$1,025	$1,656	$760	$334	$856	$1,949	($293)
LEVELIZED REVENUE REQUIRED -$/YR			$54	$22	$124	$200	$92	$40	$103	$236	
LEVELIZED COST- MILLS/KWh			21	8	47	76	35	15	39	90	

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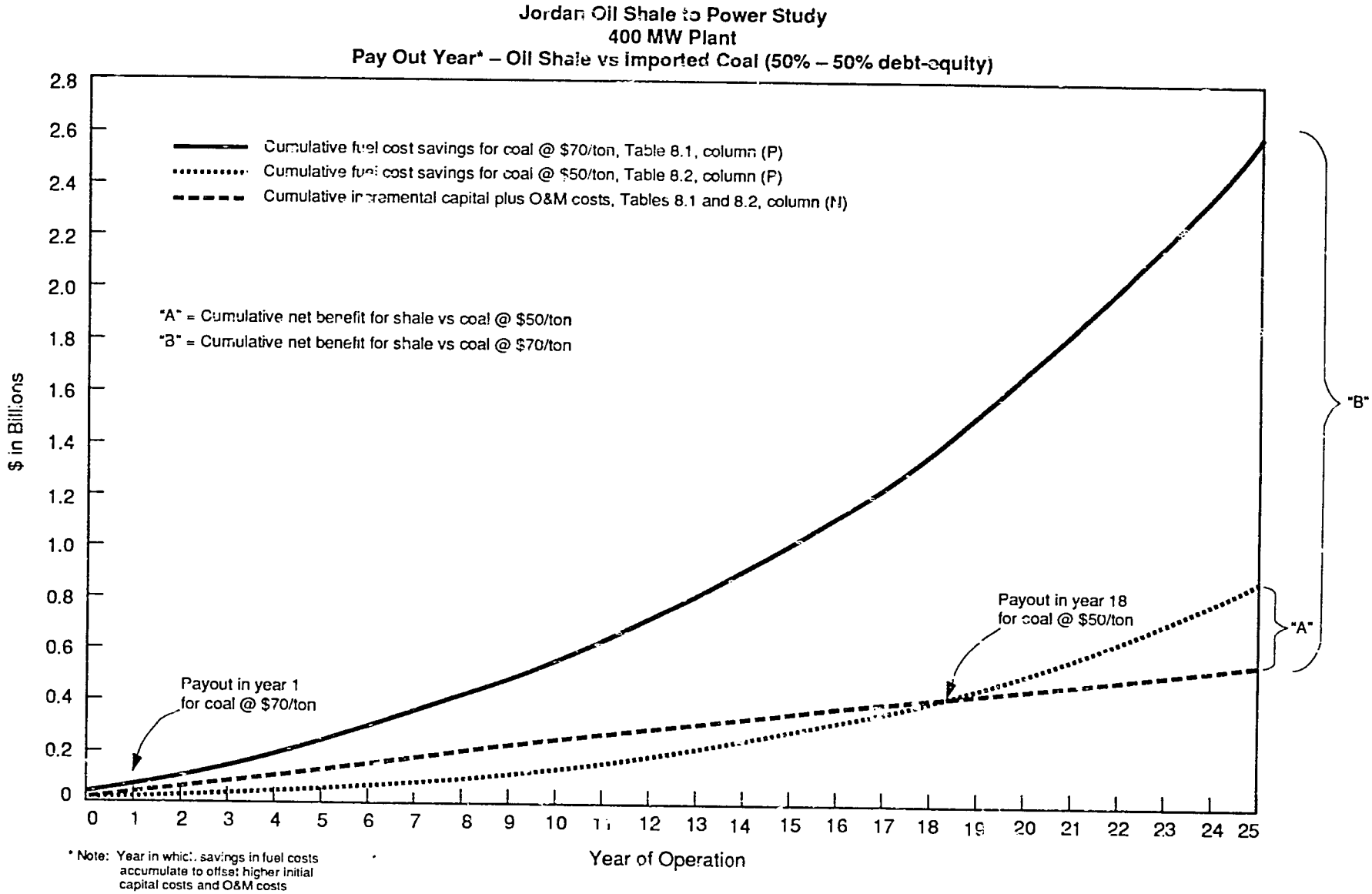

Figure 8-1 Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Coal

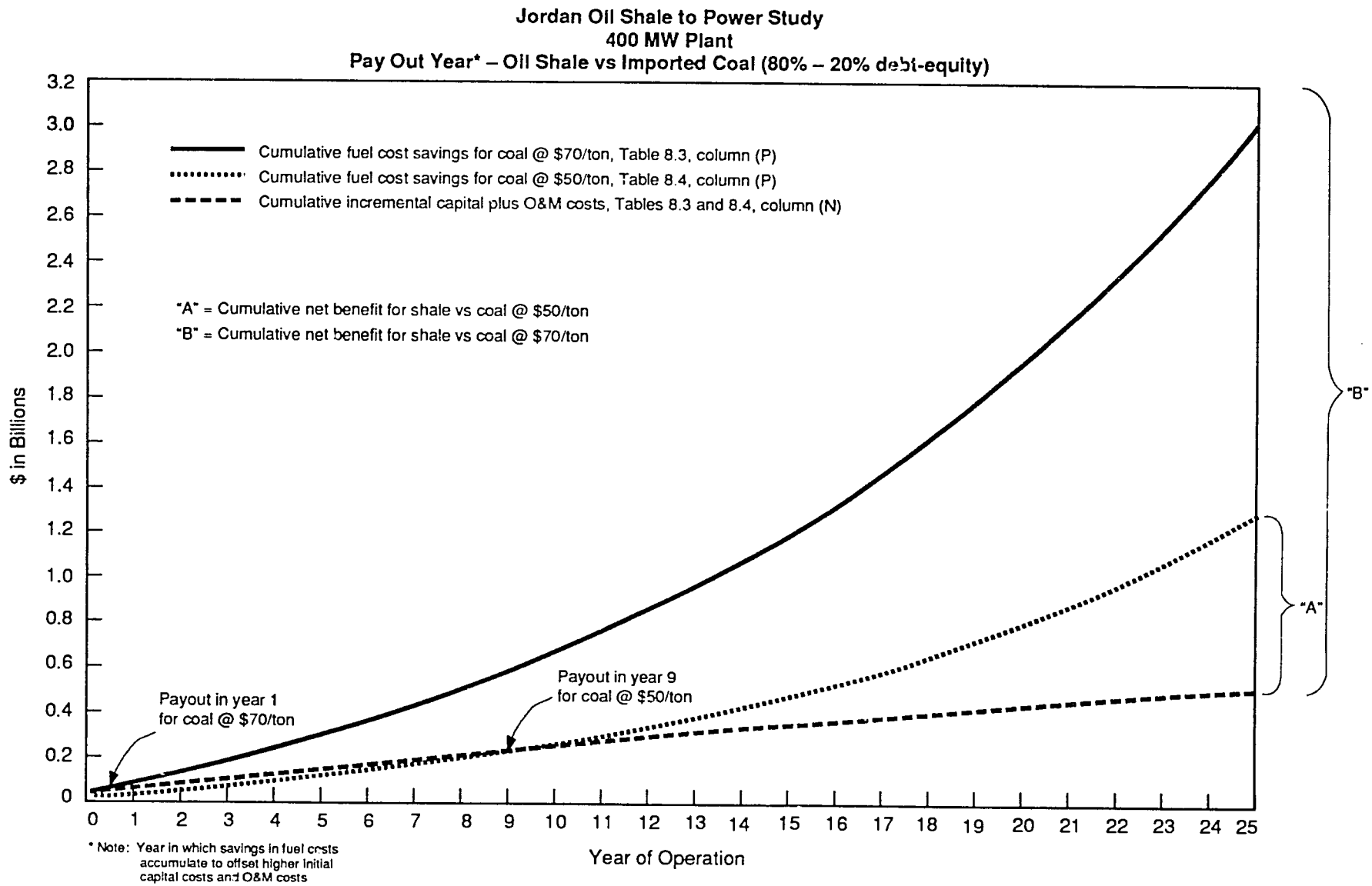

Figure 8-2 Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Coal

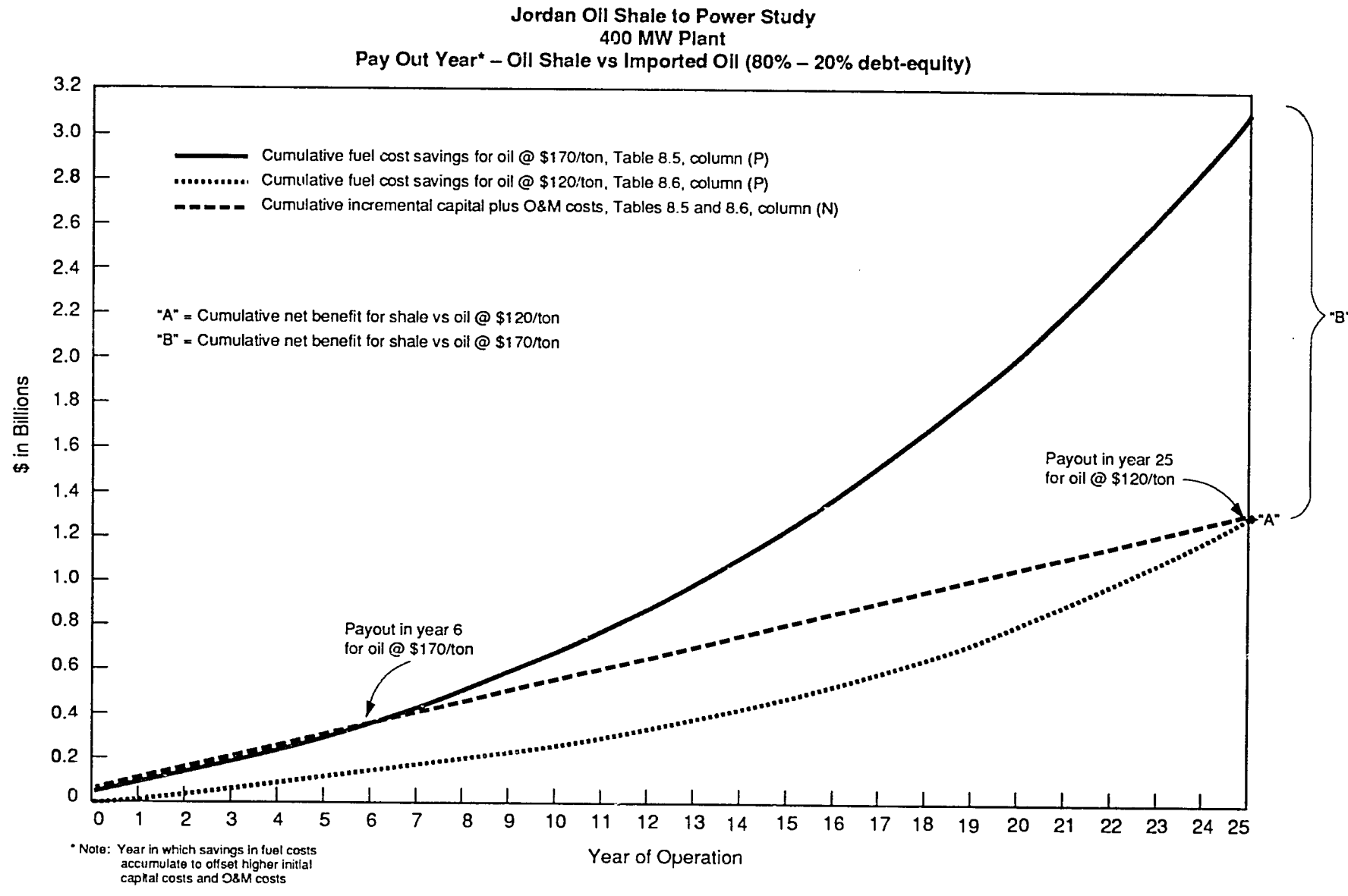

Figure 8-3 Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Fuel Oil

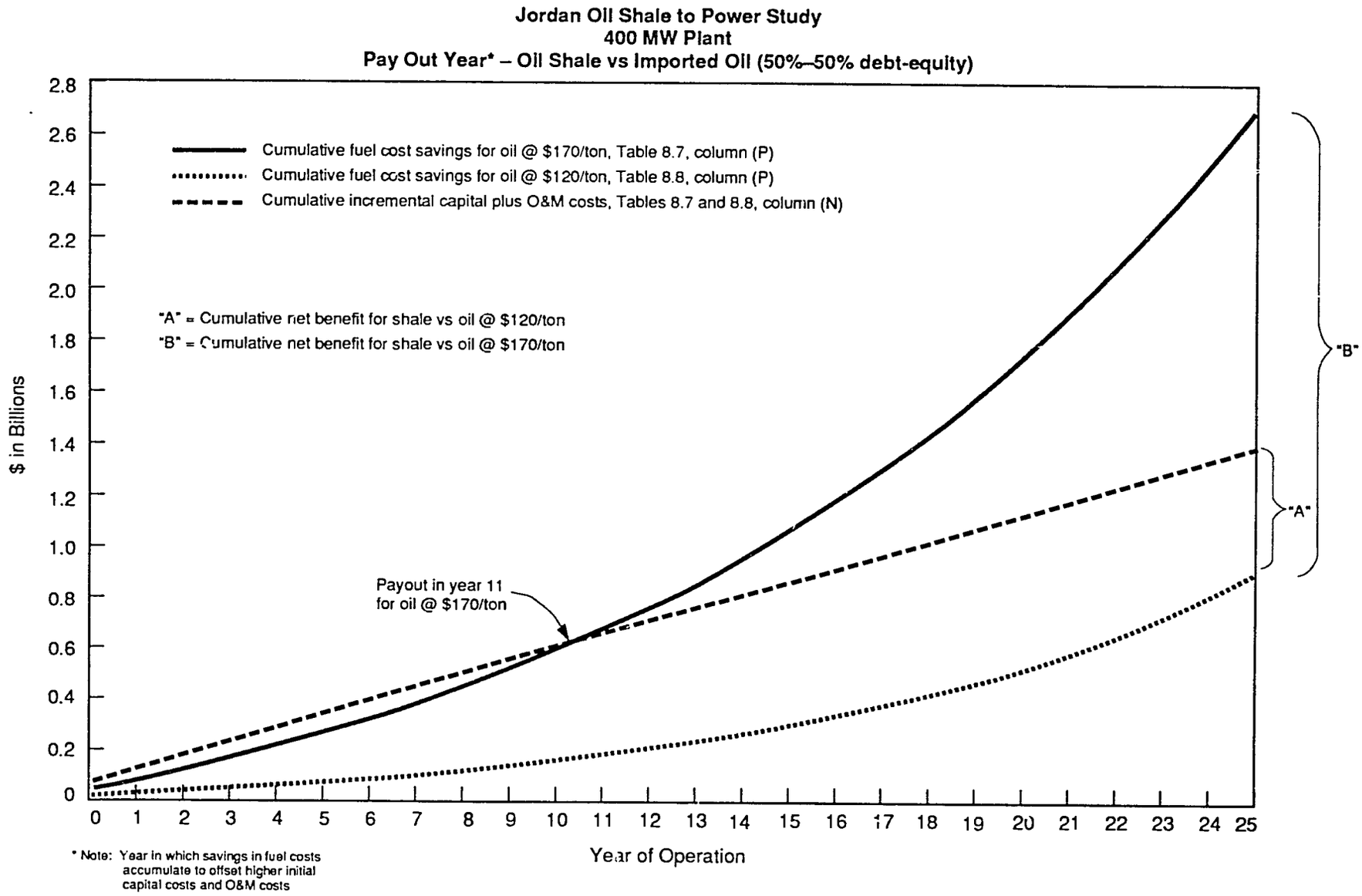

Figure 8-4 Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Fuel Oil

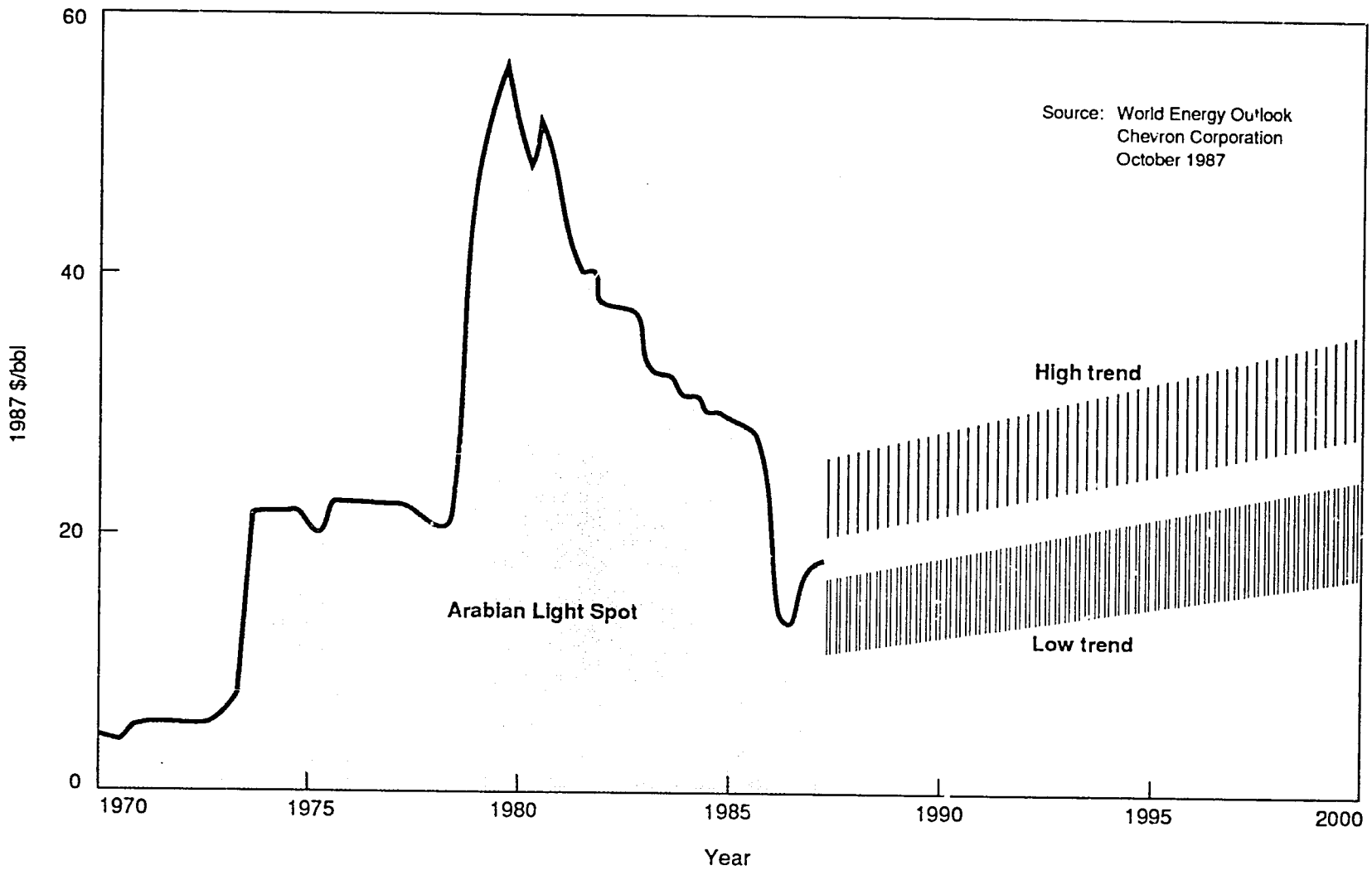

Figure 8-5 Crude Oil Price Trends

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Section 9
Technical Risk Assessment

Section 9

TECHNICAL RISK ASSESSMENT

As discussed in the previous sections the oilshale-to-power project comprises integration of several unit operations:

- o Mining
- o Shale Processing (Crushing and Material Handling)
- o Shale Combustion (CFBC Boiler)
- o Power Generation
- o Waste Disposal
- o On-Site Infrastructure
- o Off-Site Infrastructure

All of these project unit operations, with the exception of Shale Combustion, involve established, well-proven equipment and operations. The estimated installed cost of the boiler facilities in the 400 MW case study is $290 million out of a combined integrated project investment total of $1,000 million. The technical risk involved with the balance-of-plant facilities is considered minimal and subject to the usual economic considerations of a large venture capital undertaking.

The boiler plant facilities employ the innovative application of fluidized bed combustion technology to oilshale fuel. While circulating fluid bed combustion is relatively new for power plant boiler applications (10 to 12 years), the technology has been widely used in petroleum refinery FCC cracking plants for over 40 years.

The key elements of the boiler plant risk assessment are:

- o Size of prior commercial installations.
- o Fuel used in prior commercial installations.

- Operating experience to identify problem areas and expected onstream operating factors with high ash content fuel.

Prior CFBC commercial CFBC installations have been in the 20 to 50 MW size range. One unit the 110 MW Colorado-UTE coal fired boiler at Nuclear Colorado, recently started up. CFBC plants have demonstrated capability of handling a wide variety of fluels: bituminous coal, lignites, coal washery tailings, anthracite culm, wood waste, peat, industrial wastes and sludges, petroleum coke and others. High sustained capacity factors exceeding 90 percent have been demonstrated with many of these fuels. The closest analogue to the oilshale operation planned at Sultani is the catalyst regenerators of every FCC cracking plant in a modern petroleum refinery. The latter feeds a high ash fuel (spent catalyst) containing 10 to 20 percent carbon. The successful operating history of these plants lends creditability to the proposed oil shale combustion application planned for Jordan.

While even well established processes encounter technical problems from time to time, the use of modern technical service staffs together with good plant instrumentation and trained professional operating staffs leads to high operating efficiencies. Any process plant operation will need a good engineering and laboratory backup to maintain and achieve good on-stream records.

One can not at this time point to any large CFCB commercial boiler plant operating with oilshale as fuel for a sustained period of time. However the many large FCC plant catalyst regenerator facilities show excellent, long-term sustain operations. The combustion chamber and the backend of an FCC plant regenerator has all of the same basic elements that are in a Pyroflow boiler facility.

The Oak Ridge National Laboratory has made a specific assessment as applied to Sultani Oil Shale (see Appendix 6). Their results are as follows:

> "Circulating fludized bed technology in general has progressed to the point that there appears to be no question of its feasibility. Successful operation has been demonstrated burning a variety of solid fuels in plants

of up to about 110 MW output. Larger plants, up to 160 MW, are in the initial phases of operation and, within the next 2-3 years, they should provide much evidence of the viability of larger plants.

The combustion tests of Jordanian oil shale in the Ahlstrom CFB test unit indicate that the shale should burn readily and yield low NO_x and SO_2 emmissions in a CFB combustion system. The high volatile content of the fuel is a major contributing factor to its good combustion. The major disadvantages of the fuel are, of course, its low-heating value and high ash content. A large fraction of the shale blows through the combustor as fly ash which yields a high ash loading in the hot cyclone and convection tube banks. The primary potential problem areas are associated with the high ash content: (1) bottom ash removal from the combustor, (2) high flow rate of recycle solids through the hot cyclone and return leg, (3) fly ash deposition and erosion of the convection tube banks, and (4) erosion of superheater tubes in the combustor.

<u>20-MWE Plant</u>. The technical risk should be fairly low for a 20-MWe demonstration plant. Eighteen plants of this size or larger have been built by Ahlstrom or its subsidiaries which have operated for a year or longer and have demonstrated availabilities of 95 percent or more. The major areas of concern are the high flow rate of solids through the hot cyclone and return leg and the high fly ash loading in the flue gas which may lead to deposition and erosion in the convection tube banks. The design proposed by Pyropower should minimize the risk of deposition or erosion in the convection tube banks because the flue gas velocities will be low and steam soot blowers will be used.

While the technical risk for a 20-MWe plant appears to be low, successful demonstration of this size plant may not provide adequate experience for scaling up to a 100-MWe plant. It may be necessary to operate a 50-MWe plant before attempting to scale up to 100 MWe.

<u>50-MWE Plant</u>. The technical risk is moderate for a 50-MWe plant. There is some operating experience with plants of this capacity firing coal or

other low- to medium-ash fuel, but there is not yet any experience with high-ash fuel in plants this large. A 35-MWe plant fired with anthracite culm is scheduled to begin operating this year, which should yield valuable information relative to operation with high-ash fuel.

The major areas of technical risk are associated with removal and handling of bottom ash from the combustor, high flow rate of recycle solids through the hot cyclone and return leg, fly ash deposition and erosion in the convection tube banks, and erosion of superheater tubes in the combustor. The ash flow rate for the 50-MWe plant is about 10 times the ash flow rate of the Nucla (Colorado Ute) plant, the largest CFB plant Pyropower has built to date.

100-MWE Plant. The technical risk is fairly high to build a 100-MWe plant as the first unit. There is no plant this large operating or under construction which is designed to operate on high-ash fuel. The Nucla plant has an output of 110 MWe, but it is designed for operation with coal with an ash content of about 20 to 25 percent. There have been some startup problems with the Nucla plant. One problem has been irregular flow of recycle solids in the cyclone return legs, apparently caused by restrictions or plugging from poor fluidization in the loop seals. Experience derived from the 2-year test program planned for the Nucla plant by EPRI will contribute greatly to the knowledge base for design of the larger plants. The high ash content of the Jordan oil shale will make the scaleup to a 100-MWe plant for this fuel more challenging than for coal."

Considering the foregoing it is concluded that the initial undertaking at Sultani should be a 50 MW size project. The reasons for this recommendation are the following:

- Economics for a 20 MW size project are poor requiring substantial subsidy for the power produced.
- Scale up to the 100 MW commercial size unit boiler from 20 MW involves significantly greater design extrapolation than going up from a 50 MW size prototype. (If the Jordan Shale Program were delayed 5 years, the technical risk of scale-up will be greatly reduced.)

- Pyropower Corporation has stated that it stands ready to warrant the operation of a 50 MW size boiler fueled with Sultani oilshale.

- An initial 50 MW size boiler can be readily integrated into the first 100 MW incremental power generation capacity of the proposed 400 MW Commercial Scale Project. After the first 50 MW Prototype boiler has completed its demonstration operations a second 50 MW boiler would be added to complete the initial 100 MW generating facility.

- The principle lessons to be learned in a smaller demonstration scale project really are limited to showing that the technology works. This can be achieved in other ways - such as contracting for a demonstration burn of Jordan oilshale in an existing CFBC unit owned by others.

The technical risks involved in proceeding with a 50 MW Prototype Project appear to be reasonable and acceptable for the 1992/93 time-frame being considered for starting this program.

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Section 10
Recommended Action Plan

Section 10

RECOMMENDED ACTION PLAN

The results of the Prefeasibility Study indicate that development of Jordan's oil shale resource at the Sultani deposit to provide fuel for power generation is both technically and economically viable under certain conditions. It is concluded that JEA is justified in expanding efforts toward commercialization of its oil shale to power program.

The following efforts will involve new work in three basic areas:

- o Continuing studies of fundamental factors affecting the Prefeasibility Study conclusions.
- o Creation of bankable documents suitable for contractual purposes for an integrtated oil shale to power project.
- o Creation of an entity to carry out the business and operating responsibilities of an oil shale to power project.

One basic decision that must be reached at the beginning of this next phase is the matter of whether to pursue both a Demonstration Project and a Commercial Scale Project. The results presented in this Prefeasibility Study show that the cost of power from a 20 MW and a 50 MW size shale project will require substantial subsidy to be economically viable. Unless the Government of Jordan is prepared to provide such subsidy, then the only recourse is to focus continuing work on a 100 MW size shale power plant. If on the other hand there is strong desire to see the operating results from a $110 million to $165 million Demonstration Project before embarking upon a $1 billion Commercial Scale Project, then the work plan for the next phase must embrace carrying out both programs simultaneously.

For these shale-to-power studies the following basic assumptions are made:

1. On-going studies of the natural gas discovery at Risha will establish that its reserves and producibility are not large enough to meet the post year 2000 electric power generation fuel requirements.

2. Import costs for petroleum crude oil and for coal will escalate during the late 1990s significantly above the current levels of $17/Bbl ($120/tonne) and $50/tonnes respectively.

10.1 CONTINUING STUDIES

During the Prefeasibility Study it was noted that the following matters deserve further study:

- o Reduction of Demonstration Project investment by using "contract" mining.
- o The availability suitability, condition and need for rehabilitation of idle mining equipment in Jordan needs more in-depth study. The funding of depreciated mining equipment needing replacement also must be considered.
- o Additional pilot plant testing
  - to meet the needs of Section 10.2, i.e. creation of bankable documents.
  - to define stable ignition lower threshold for Btu/lb.
  - to provide a firm basis for commercial scale plant design.
  - to provide a basis for process performance warranties.
- o Conduct crushing pilot plant studies on various shale grades.
  - Examine effect of chert and limestone stringers in meeting 8 mm size specification.
- o In depth study of forecasts for Jordan GDP growth for the periods 1990-1995, 1995-2000 and 2000-2005 including further evaluation of power export prospects.
- o Studies of existing base load power plants to determine if their availability (capacity factor) can be upgraded.
- o Creation of environmental models for Sultani area.
  - Air (baseline data and emissions dispersion)
  - Water (baseline data and leachate dilution)
- o Continue detail core drilling core analysis program at Sultani.

- Evaluate prospects for recovery of underlying by-product phosphate.

- Evaluate effect of Sultani oilshale project on Zarqa refinery.

10.2 CREATION OF BANKABLE DOCUMENTS

This involves preparation of detailed Feasibility Studies as follows:

- Create site specific detail designs for all facilities in an Integrated Project, (i.e. Mine, Shale Processing, Power Plant, Community Facilities).

- Develop specifications for all equipment in an Integrated Project.

- Obtain vendor quotations for all specification equipment.

- Define project capital requirements including a construction schedule.

- Define project operating requirements including labor, maintenance and utility supplies.

- Re-examine project economics.

10.3 OUTLINE REQUIREMENTS OF A SHALE-POWER BUSINESS ENTITY

- Examine organizational alternatives
  - Define responsibilities and interfaces of participants.
- Explore professional and craft labor availability
  - Resources in Jordan
  - Need for Expatriate Staff
- Define applicable laws and regulations
- Define applicable tax considerations
- Define necessary permits and authorization
- Define purchased utilities to be consumed
  - Purchased power
  - Water

- Define GOJ role in providing off-site infrastructure
- Explore project financing options.

The development of a plan of work, a budget and a schedule for this next phase has not been undertaken pending:

- Approval to proceed
- Availability of new funding

It is expected that this next phase of the Jordan Oil Shale to Power Develoment Program will consume 1 to 2 years elapsed time and require expenditure of $3 to 4 million of additional funding. However a more detailed development of these work efforts must be done and a specific work scope proposal prepared to define the budget for this next program phase. Early funding for the preparation of the program plan, schedule, and budget for this next phase is recommended to maintain the momentum and continuity from the Prefeasibility Study.

Volume II of this Prefeasibility Study Report contains some amplification material relating to the suggested follow-on action plan.