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Report No. 89-02

A Report of the

Office of Energy
Bureau for Science and Technology
United States Agency for International Development

# PREFEASIBILITY STUDY

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

VOLUME II OF VI
ORAL PRESENTATION,
QUESTIONS AND ANSWERS

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JORDAN OIL SHALE TO POWER
PREFEASIBILITY STUDY

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MARCH 1989 PREFEASIBILITY STUDY PRESENTATION

# PREFEASIBILITY STUDY

# OIL SHALE FUELED POWER GENERATION

## Presentation to

## HASHEMITE KINGDOM OF JORDAN

## March 1989

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# OUTLINE

- Introduction
- Technical feasibility
- Economic feasibility
- Study conclusions
- Recommended action plan

# Introduction

- Study program
- Integrated project scope

# STUDY PROGRAM

| Task | Assignment |
|---|---|
| ■ Program management | Bechtel |
| ■ Test sample procurement | JEA/NRA |
| ■ Test burn report | Pyropower |
| ■ Jordan power demand assessment | ORNL |
| ■ 20/50 MW boiler design/cost | Pyropower |
| ■ 20/50 MW project BOP *design/cost | Bechtel |
| ■ 4x100 (factored) boiler design/cost | Pyropower |
| ■ 4x100 (factored) BOP design/cost | Bechtel |
| ■ Environmental assessment | ORNL/Bechtel |
| ■ Economic assessment | Bechtel/ORNL |
| ■ Risk assessment | ORNL/Bechtel |
| ■ Action plan | Bechtel |
| ■ Final report | Bechtel, et. al |

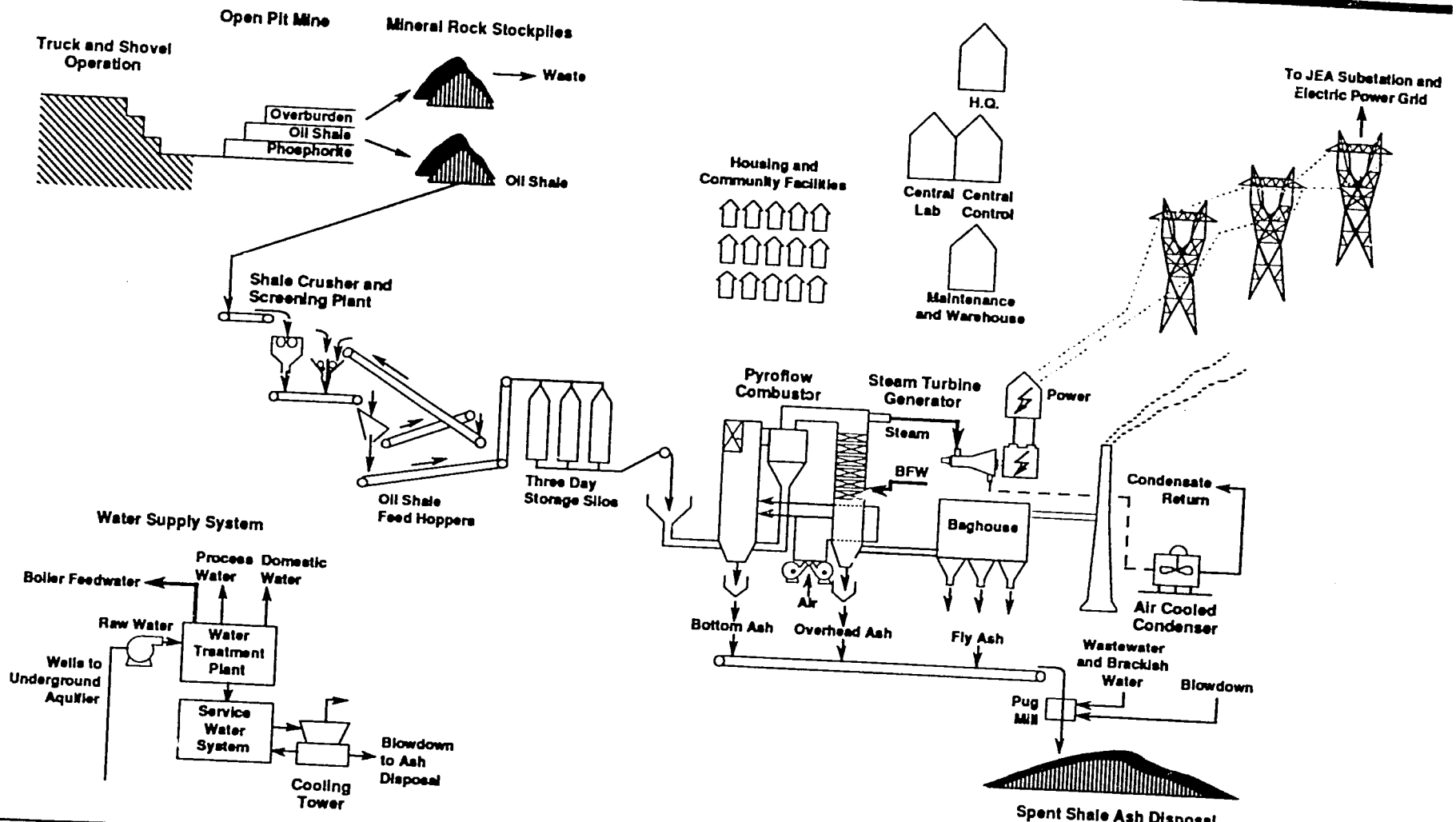
* BOP = balance of plant

# INTEGRATED PROJECT SCOPE

For 20/50/4x100 MW installations

- Open pit mine
- Oil shale processing
- Power block
  - Boiler plant
  - Power generation facilities
  - Raw water supply/treating
- Ash disposal system
- Onsite infrastructure
- Offsite infrastructure

# Conceptual Facilities




Prefeasibility Study
Oil Shale Fueled Power Generation

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# TECHNICAL EVALUATION *

- Pilot plant test program
  - 75–ton sample procurement
  - Test results
  - Test conclusions
- Conceptual design studies
  - Oil shale reserves and analyses
  - Mine and shale processing
  - Power plant and auxiliaries
  - Development schedule

* Material developed by Pyropower and Bechtel

# Technical Feasibility

- Technical evaluation
- Technology risk assessment
- Environmental assessment
- Power demand versus supply assessment

# Pilot Plant Test Sample

| | Expected Avg. Mine–Run Shale[a] | Blended 75–ton Sample[b] |
|---|---|---|
| Fischer assay oil content, wt% | 7.5 | 8.4/8.6 |
| Organic carbon, wt% | 10.2 | ±13[c] |
| Gross calorific value, Btu/lb | 2000 | 2250[c] |
| Sulfur content, wt% | 2.38 | 2.55[c] |

(a) Bechtel evaluation of core hole data
(b) NRA analysis
(c) By correlation with Fischer assay

# Pilot Plant Test Program

- Conducted at Ahlstrom Laboratory, Finland
- Performed 8 test runs
- Tested four process conditions
  - Primary/secondary air ratio
  - Bed $\Delta P$ = 40/50/70 M bar
  - Load level = 40/60/100 pct
  - Combustion temperature = 830 to 900°C

# Pilot Plant Test Program (Cont'd)

- Analyzed one blended sample of shale
  - Calorific value = 5.32 – 5.97 MJ/kg (approx. 2,250 Btu/lb)
  - Carbon content (dry solids) = 16.2 – 18.7 wt%
  - Sulfur content (dry solids) = 3.0 – 3.3 wt%
  - Ash content (dry solids) = 66.7 – 68.4 wt%
  - Shale size = minus 8 mm
- Key items determined
  - Combustion efficiency
  - Product ash distribution
  - Product gas $SO_2/NO_x/CO$ content
  - Data for boiler design
  - Sulfur emissions reduction by Ca in fuel

# Pilot Plant Test Results

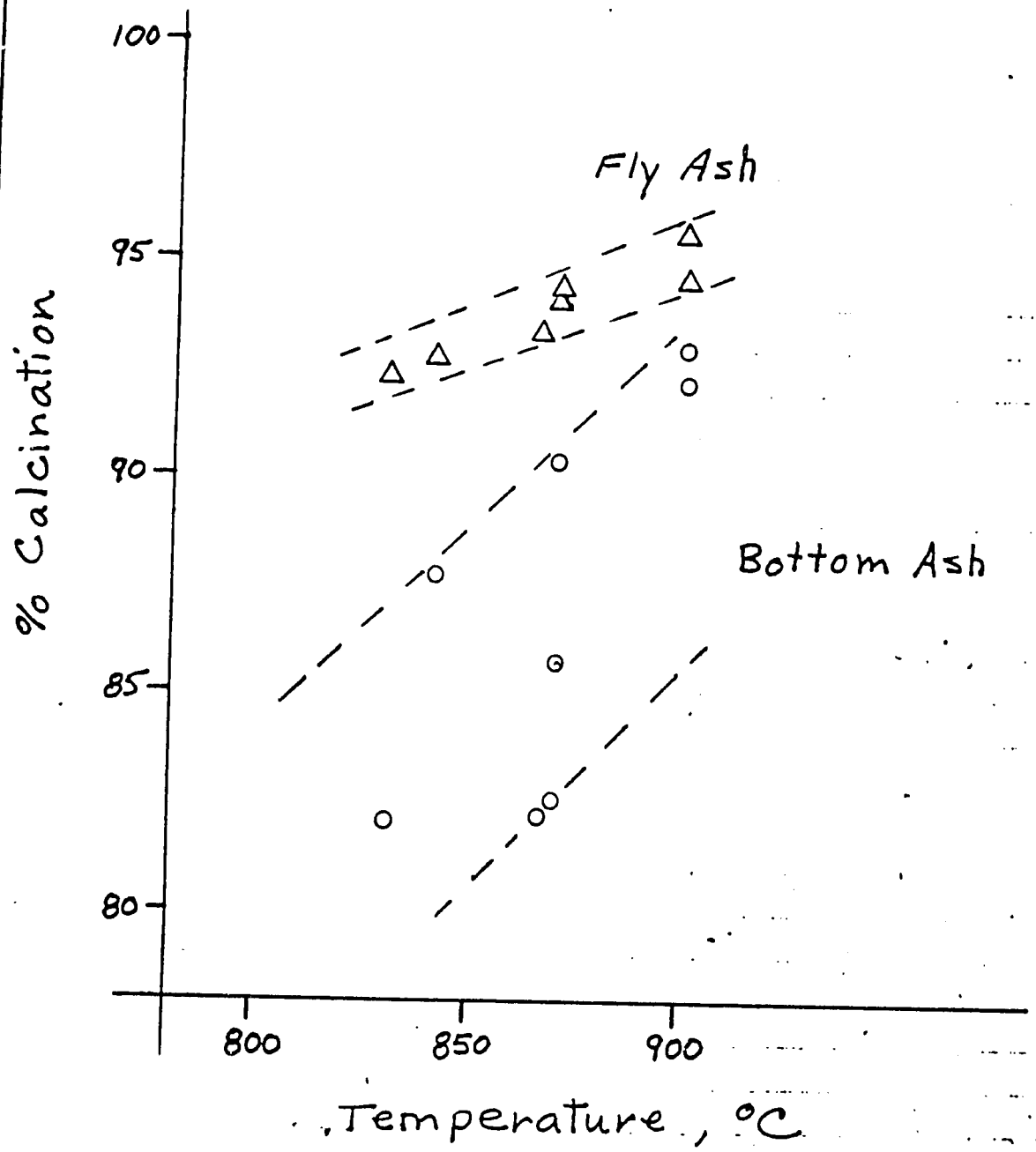
- Combustion efficiency exceeded 98.5% in all tests
- Ash distribution (btm ash/fly ash) was 35/65 to 47/53 at 100% load, typically 40/60
- Low emissions were demonstrated

| | | Typically |
|---|---|---|
| $SO_2$ | 10 to 200 ppm | > 95% removal; limestone addition not required |
| $NO_x$ | 60 to 120 ppm | < 0.20 lb/$10^6$ Btu |
| CO | 10 to 90 ppm | < 50 ppm |

PYROPOWER

TITLE

Temperature vs. % Calcination

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|---|---|---|---|---|
| | | | | |

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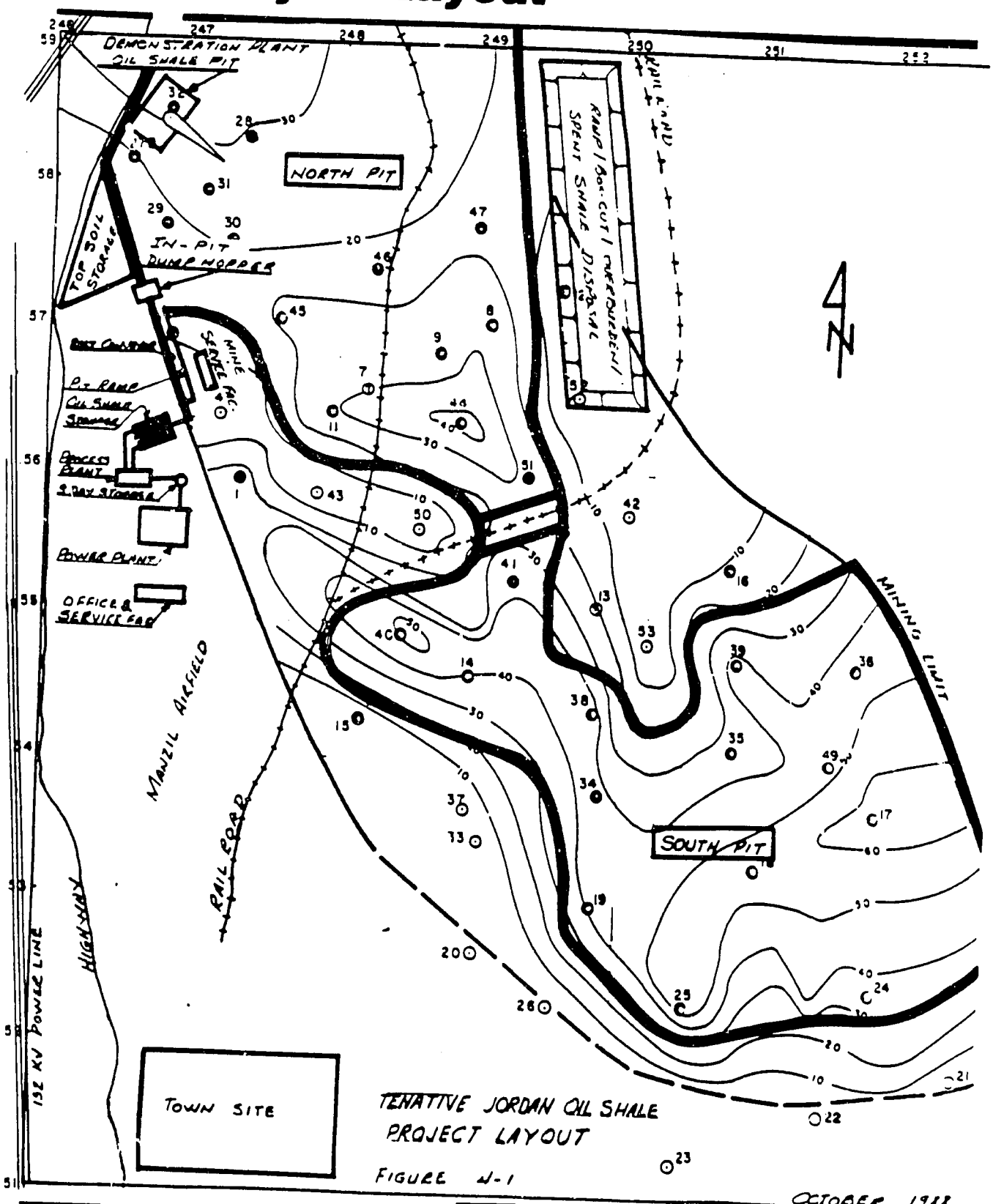
# *Pilot Plant Test Conclusions*

- It is technically feasible to burn the Sultani oil shale furnished by NRA in a Pyropower boiler
- A high combustion efficiency in excess of 98.5% was demonstrated
- $SO_2/NO_x/CO$ emissions are all acceptably low, with no limestone addition required

# Conceptual Design Studies Scope

- Three project sizes
  - 20 MW
  - 50 MW
  - 400 MW (4x100), factored for power plant portion
- Open–pit mine
  - Shale processing at the surface
  - Waste disposal system
- Power block
  - Boiler
  - Steam turbine
  - Auxiliaries

# Project Layout




TENATIVE JORDAN OIL SHALE PROJECT LAYOUT

FIGURE N-1

OCTOBER 1988

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# Sultani Oil Shale Reserves *

| | North Area | South Area | Total |
|---|---|---|---|
| Mineable shale, tonne x $10^6$ | 320 | 658 | 978 |
| Fischer assay oil content, wt% | 7.44 | 7.61 | 7.65 |
| Overburden, $m^3$ x $10^6$ | 384 | 627 | 1011 |
| Stripping ratio, $m^3/m^3$ | 2.16:1 | 1.71:1 | 1.86:1 |

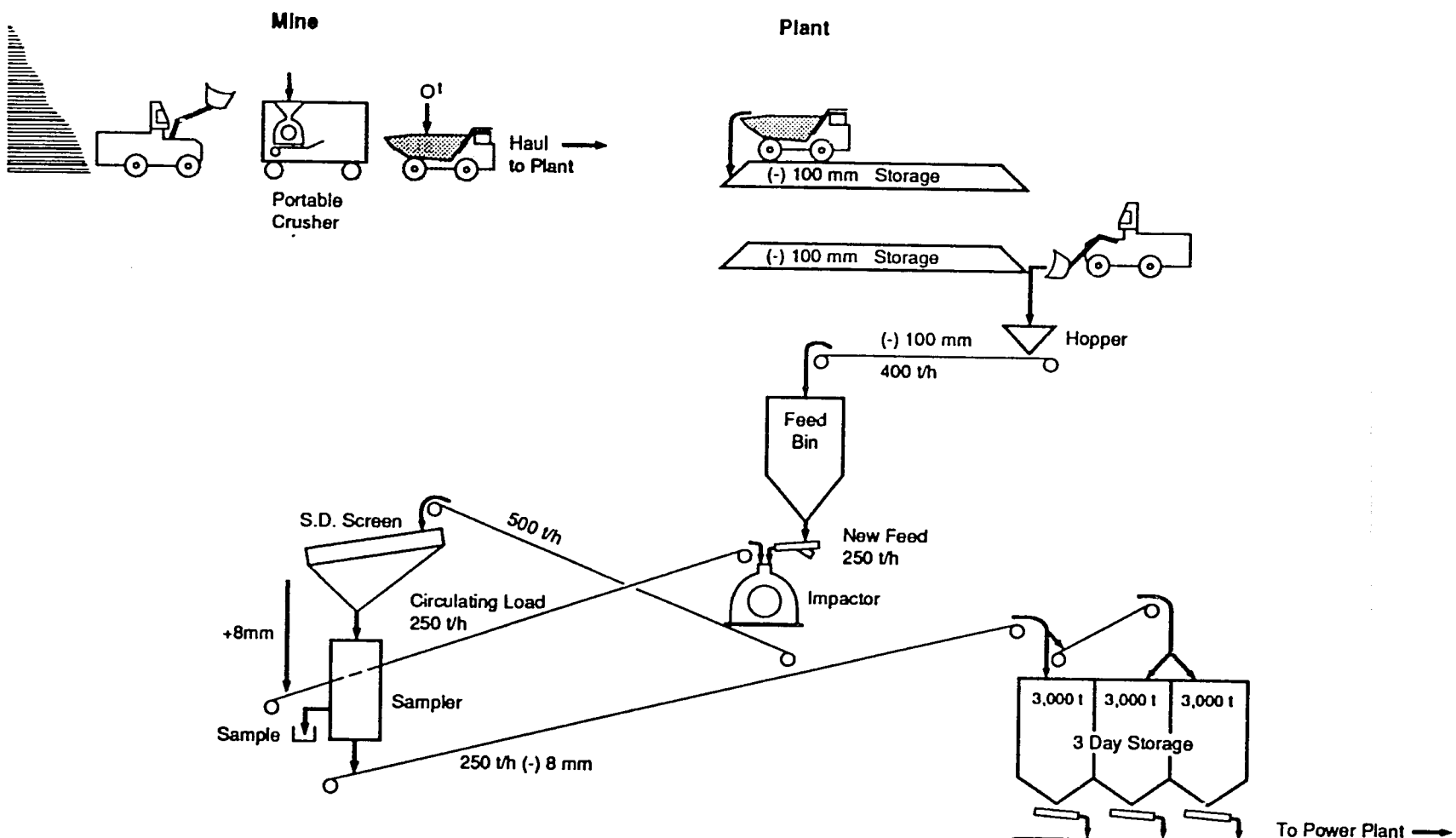
* Based on NRA core drilling and core analysis

# Sultani Oil Shale Analyses *

| | Design Basis Fuel | Low Calorific Value Fuel | High Calorific Value Fuel |
|---|---|---|---|
| Moisture | 3.20 | 3.20 | 3.20 |
| Ash (less $CO_2$ in $CaCO_3$) | 66.80 | 67.30 | 66.25 |
| $CO_2$ (in $CaCO_3$) | 13.87 | 14.14 | 13.37 |
| Carbon (organic) | 11.32 | 10.20 | 12.50 |
| Hydrogen | 1.13 | 1.02 | 1.25 |
| Nitrogen | 0.48 | 0.58 | 0.38 |
| Sulfur | 2.55 | 2.38 | 2.71 |
| Oxygen (by diff.) | 0.65 | 1.18 | 0.34 |
| Total | 100.00 | 100.00 | 100.00 |
| High heating value, Btu/lb | 2250 | 2000 | 2500 |
| Fischer assay oil content | 8.40 | 7.50 | 9.25 |

* Percent by weight

# 50 MW Oil Shale Processing Prototype Plant




Prefeasibility Study
Oil Shale Fueled Power Generation

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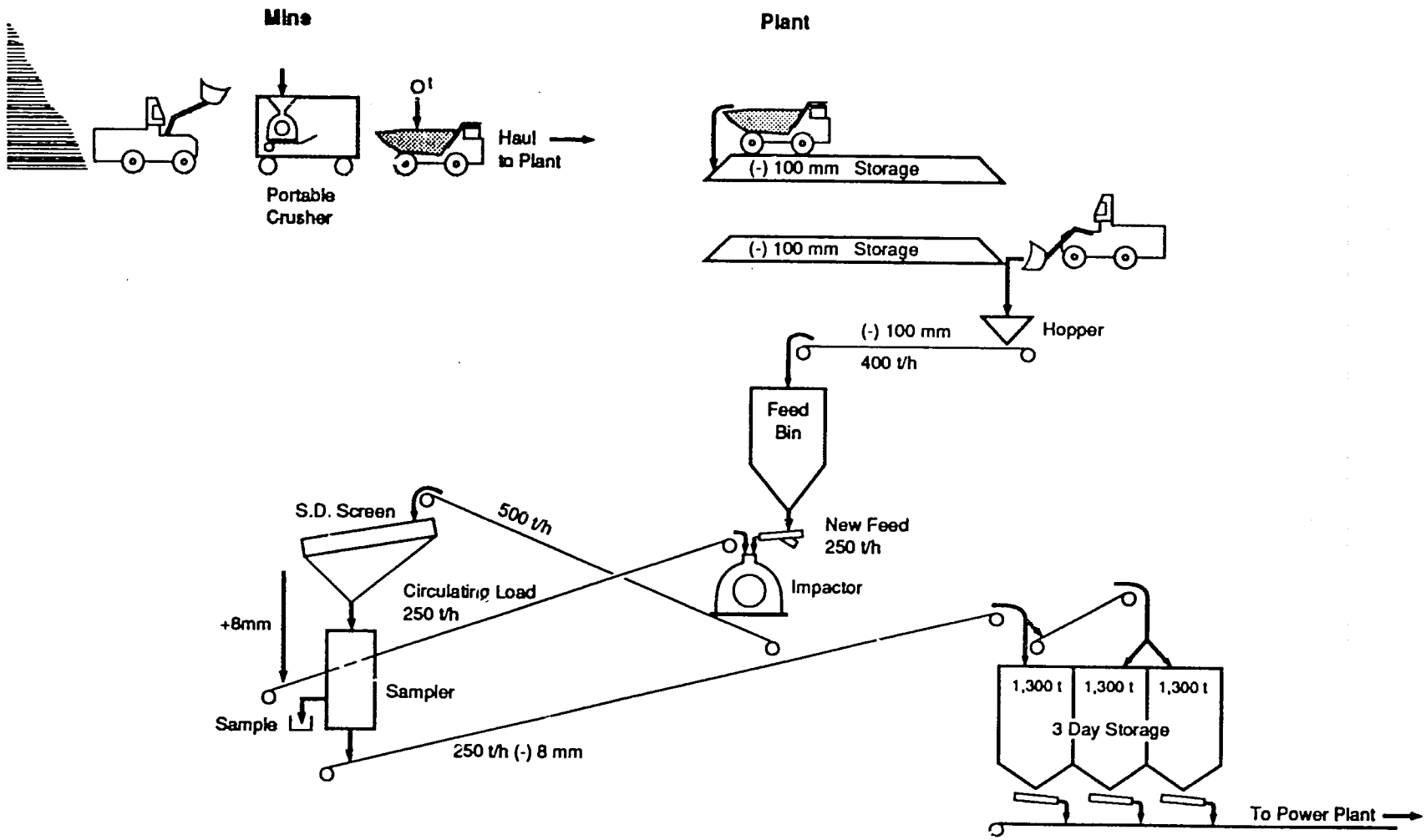
3-14-89 rs/pc:1

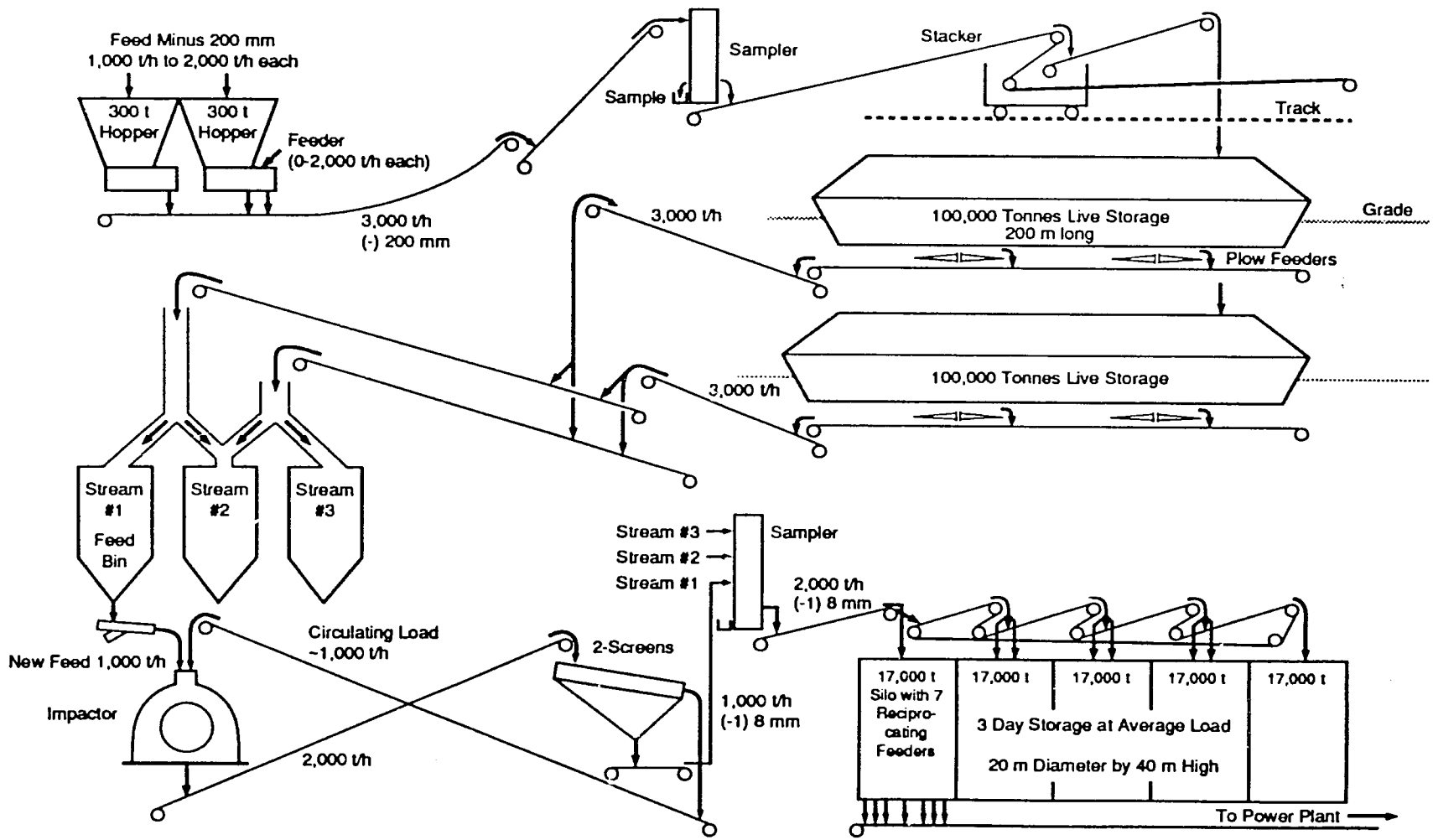
# 20 MW Oil Shale Demonstration Plant



# Mine and Shale Processing Design – 20/50 MW Project

- Overburden removal (north pit area), 10–meter benches
  - Drill and blast
  - 10 $m^3$ front–end loader
  - 77–ton truck haulage
- Oil shale mining, 10–meter benches
  - Ripper and auger scraper
  - Front–end loader
  - Portable in–pit crusher
  - 77–ton truck haulage
- Oil shale processing
  - Feed = minus 100 mm
  - Product = minus 8 mm
  - Capacity = 250 tph
  - Reversible impactor
  - Two vibrating screens

# 400 MW, Full-Scale Oil Shale Processing Plant




Prefeasibility Study
Oil Shale Fueled Power Generation

17958/9:6a/Jordan/118
3-14-89 rs/pc:1

# Mine and Shale Processing Design – 4x100 MW Project

- Overburden removal (north area), 10–meter benches
  - Drill and blast
  - Three 20 $m^3$ shovels
  - 136–ton truck haulage
- Oil shale mining, 10–meter benches
  - Two mechanical surface miners
  - 136–ton trucks to pit hopper
  - Belt conveyor = 2000 tph
  - Traveling stacker
- Oil shale processing
  - Feed = minus 200 mm
  - Product = minus 8 mm
  - Capacity = three 1,000 tph units

# Steady-State Production Schedule

| | Hourly Design Capacity | Avg. Daily Production | Annual Production |
|---|---|---|---|
| Overburden removal, bench $m^3$ | | | |
| 20 MW demo project | 282 | 1,690 | 507,000 |
| 50 MW prototype | 234 | 4,217 | 1.3 million |
| 4x100 MW full-scale plant | 1,850 | 33,333 | 10 million |

| | Hourly Design Capacity | Max. Daily[a] Production | Annual[b] Production |
|---|---|---|---|
| Oil shale mining and shale processing, tonnes | | | |
| 20 MW project | 250 | 1,733 | 390,000 |
| 50 MW project | 250 | 4,324 | 973,000 |
| 4x100 MW project | 2,000 | 34,578 | 7.8 million |

(a) Based on 100% operating factor for power block

(b) Based on 75% operating factor for power block ( 20 MW project = 300 shifts/yr; 50 MW project = 900 shifts/yr; 400 MW project = 900 shifts/yr)

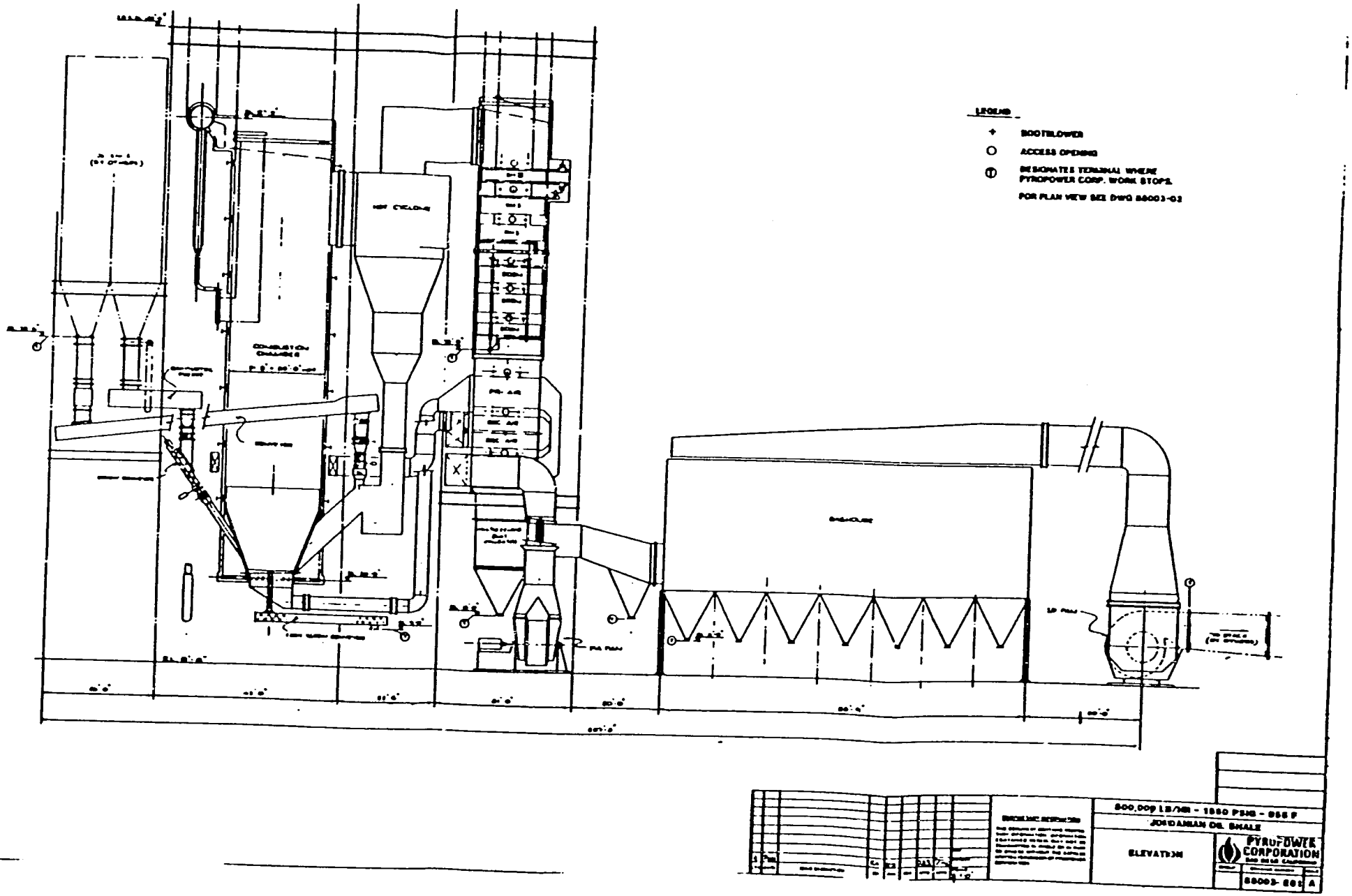
# Conceptual Power Plant Plans

- Pyroflow boiler
- Power generating facilities
- Auxiliaries

# Pyroflow Boiler Steam Conditions*

| | |
|---|---|
| ■ Flow rate | 226,700 kg/hr (500,000 lb/hr) |
| ■ Pressure | 109.9 kg/cm$^2$ abs (1563.5 psia) |
| ■ Temperature | 512.8°C (955°F) |

* Same for 20, 50, and 100 MW designs


LEGEND
BOOTBLOWER
ACCESS OPENING
DESIGNATES TERMINAL WHERE PYROPOWER CORP. WORK STOPS.
FOR PLAN VIEW SEE DWG 88003-02
HOT CYCLONE
COMBUSTION CHAMBER
BAGHOUSE
800,000 LB/HR - 1550 PSIG - 955 F
JORDANIAN OIL SHALE
ELEVATION
PYROPOWER CORPORATION
88003-E01 A

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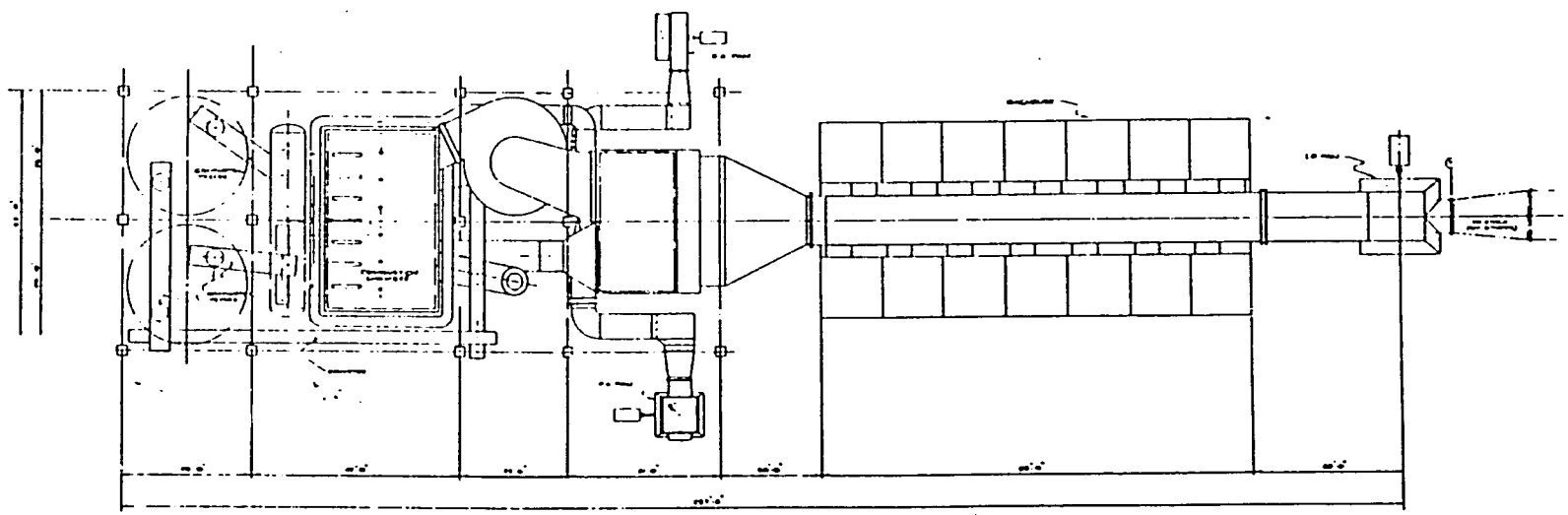


LEGEND

① DESIGNATES TERMINAL WHERE PYROPOWER CORP. WORK STOPS.

FOR ELEVATION VIEW SEE DWG 50063-001

| | | |

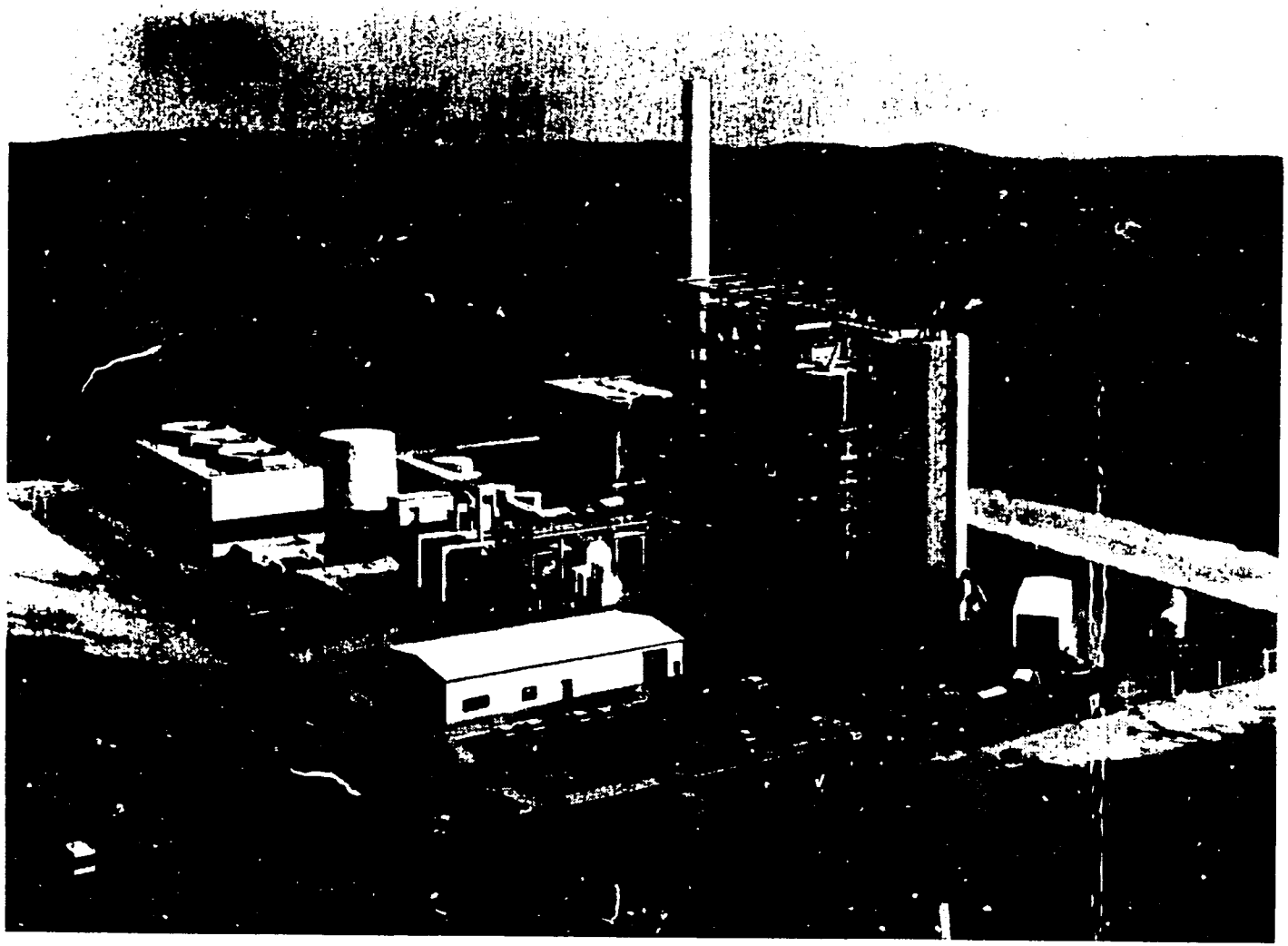
# Power Block

- Fuel handling system
  - Day bins/screw feeders
- Boiler
  - Pyroflow circulating fluid bed combustor
- Power generation
  - Non reheat condensing steam turbine
  - Conventional Rankin steam cycle
- Ash handling system (btm ash from combustor, and fly ash from bag house)
  - Wetted in pug mill to add 20± wt% water;
- Plant service water
  - Air–cooled condensors and small cooling tower from circulating trim water coolers
- Plant raw water
  - To cooling tower makeup
  - To drinking water system
  - To pump seals, etc.
- Plant treated makeup water
  - Demineralizer train

# Onsite Infrastructure

- Project office
- Control house
- Maintenance shops, warehouse
- Laboratory
- Employee service facility
- Site development/operations service facilities
  - Fire control/security
  - Communications
  - Lighting
  - Roads, drainage, and sewage

# Bechtel/Pyropower 50 MW Cogeneration Plant – Mt. Poso, California



# Characteristics of Three Size Operations

| | 20 MW | 50 MW | 400 MW (4x100) |
|---|---|---|---|
| Oil shale fuel, tpy | 390,000 | 973,000 | 7.8 million |
| Mine development excavation, bank $m^3$ | 500,000 | 1 million | 8.5 million |
| Spent ash disposal, tpy (wetted) | 327,000 | 815,000 | 6.1 million |
| Water consumption, 1,000 $m^3$/yr | 538 | 907 | 1,263 |
| Staffing required | 185 | 324 | 1,046 |
| Community population | 700 | 1,200 | 4,000 |

# Conceptual Designs Summary

- All BOP facilities involve conventional equipment and technology
- 100 MW unit operation involves boiler scale–up considerations
- Water consumption estimates
  - Requirement for 4x100 MW project is 1.3 million $m^3$/yr
  - Water allocation of 2 million $m^3$/yr of water supports 6x100 MW
- Water availability probably limits total power generation from oil shale in Jordan

# TECHNOLOGY RISK ASSESSMENT *

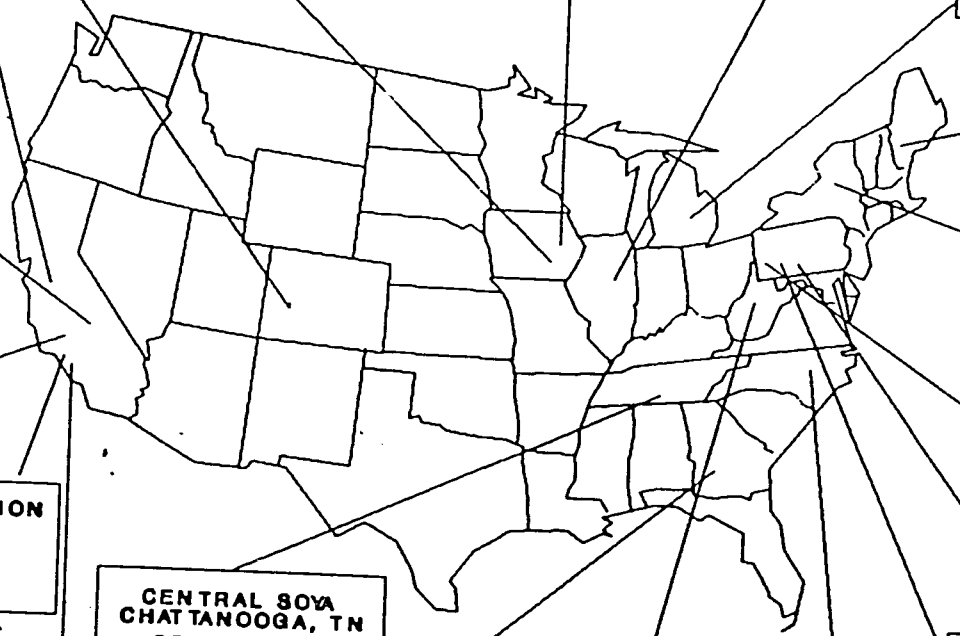
- Basic concepts
- Key boiler scale-up design issues
- Impact of scale-up
- Conclusions

* Material developed by Oak Ridge National Laboratory (ORNL) and Bechtel

## *Basic Concepts*

- CFBC is relatively new in the power industry
  - Existing plants are small, typically 20 to 50 MW
  - There is limited operating experience with high–ash fuels
  - Existing designs for lignite, biomass, and coal wastes show good plant performance
- Application of CFBC boiler design to oil shale fuel has defined risk that relates to scale–up of existing design
- Similar CFBC technology is used in petroleum refining industry
  - FCC cracking plant regenerators burn carbon residue off spent catalyst
  - FCC plant sizes equivalent to proposed power application

# PYROFLOW UNITS IN THE U.S.



COLORADO-UTE
NUCLA, CO
110 MW(e)
Start-Up: 1987

IOWA STATE UNIV.
AMES, IA
2x170,000 lb/hr
Start-Up: 1988

UNIV. OF NORTHERN IOWA
CEDAR FALLS, IA
105,000 lb/hr
Start-Up: 1990

B.F. GOODRICH
HENRY, IL
125,000 lb/hr
Start-Up: 1986

GENERAL MOTORS
PONTIAC, MI
300,000 lb/hr
Start-Up: 1986

CORN PRODUCTS
STOCKTON, CA
500,000 lb/hr
Start-Up: 1987

RUMFORD COGENERATION
RUMFORD, ME
2X415,000 lb/hr
Start-Up: 1990

CALIF. PORTLAND CEMENT CO.
COLTON, CA
190,000 lb/hr
Start-Up: 1986

FT. DRUM
WATERTOWN, NY
3X175,000 lb/hr
Start-Up: 1988

ACE COGENERATION
TRONA, CA
910,000 lb/hr
Start-Up: 1990

CAMBRIA
PENNSYLVANIA
2x395,000 lb/hr
Start-Up: 1991

MT. POSO COGENERATION
BAKERSFIELD, CA
500,000 lb/hr
Start-Up: 1989

GILBERTON POWER CO.
WEST MAHONEY, PA
2x355,000 lb/hr
Start-Up: 1988

CENTRAL SOYA
CHATTANOOGA, TN
85,000 lb/hr
Start-Up: 1986

GULF OIL EXPLORATION
BAKERSFIELD, CA
55,000 lb/hr
Operational: 1983

NORTH BRANCH
NORTH BRANCH, WV
395,000 lb/hr
Start-Up: 1991

P.H. GLATFELTER CO.
SPRING GROVE, PA
400,000 lb/hr
Start-Up: 1988

SOUTHEAST PAPER MFG. CO
DUBLIN, GA
400,000 lb/hr
Start-Up: 1989

UNIV. OF NORTH CAROLINA
CHAPEL HILL, NC
2X250,000 lb/hr
Start-Up: 1989

3/89

## FUEL ANALYSES

### High Ash Fuel Projects
### Total Solids Input Basis

| | Gilberton | Cambria | North Branch | Oil Shale |
|---|---|---|---|---|
| Carbon | 46.53 | 27.49 | 18.22 | 11.32 |
| Hydrogen | 1.53 | 1.64 | 1.60 | 1.13 |
| Sulfur | 0.73 | 2.22 | 2.34 | 2.55 |
| Nitrogen | 0.85 | 0.51 | 0.43 | 0.48 |
| Oxygen | 2.82 | 2.18 | 4.68 | 0.65 |
| Moisture | 14.51 | 5.14 | 5.57 | 3.20 |
| Ash | 33.03 | 60.82 | 67.16 | 80.62** |
| | 100.00 | 100.00 | 100.00 | 100.00 |
| HHV,Btu/lb* | 7485 | 4809 | 3453 | 2250 |

* includes limestone feed as ash

** includes $CO_2$ in $CaCo_3$

CA89029
CA:kw

# Key Boiler Scale-Up Design Issues

- Solids handling
  - Feeding shale to combustor
  - Withdrawing ash from combustor
  - Withdrawing fly ash
- Internal solids circulation of the steam generator
- Erosion/corrosion of steam generator internals
- Heat recovery from bottom ash
- Operation with low calorific-value fuel

# Impact of Scale-Up

| Project Size | Potential Risk: Design/ Operation of Initial Plant | Potential Risk: Scale-up to 100 MW Plant |
|---|---|---|
| 20 MW | Low | Significant |
| 50 MW | Modest | Modest |
| 100 MW | High | Low for duplicate units |
| 50 MW boiler in 100 MW plant | Modest | Low for duplicate units |

# Conclusions

- Defined risk of CFBC boiler is acceptable

- Operating experience with commercial CFBC boilers built and under construction will strengthen confidence level and minimize risk for a plant built in 1995

# ENVIRONMENTAL ASSESSMENT

- Mine and shale processing
  - Fugitive dust emissions
  - Noise levels
  - Leachability of disposal piles
- Power plant
  - Fugitive dust emissions
  - Gaseous emissions
  - Noise levels
  - Water effluents
- Conclusions

* Material developed by Oak Ridge National Laboratory (ORNL) and Bechtel

# Mine and Shale Processing

- Fugitive dust emissions are controllable
  - Wetting mine roads
  - Enclose crushing plant equipment
- Noise levels are controllable
  - Enclose crushing plant equipment
  - Muffle truck exhausts
  - Engineered waste disposal
- Water effluents can be controlled
  - Need good mine drainage design
  - Continue leachability studies on waste dump piles

# Power Plant

- Fugitive dust emissions are controllable
  - Baghouse design/operation will minimize particulates in flue gas
  - Wetting spent ash before disposal
- Gaseous emissions are controllable
  - Pilot test results show acceptable $SO_2/NO_x/CO$ in flue gas
  - Develop baseline data for Sultani area
  - Develop air dispersion model for Sultani

# Power Plant (Cont'd)

- Noise levels are controllable
  - Enclose boiler plant fans as required
  - Enclose turbines and pumps as required
- Water effluents are controllable
  - Continue leachability studies on spent ash disposal
  - Develop aquifer dispersion model
  - Develop sewage and garbage disposal plan

# Conclusions

- No environmental constraints are anticipated on oil shale power development
  - Gas effluents will meet World Bank standards
  - Ash disposal is manageable
  - The potential for groundwater contamination appears low
  - Water effluents will be minimal
- Continued studies to develop air and groundwater baseline data are recommended

# *Power Demand vs Supply Assessment**

- Demand growth forecasts
- Electrical generating capacity
- Power supply forecasts
- Conclusions

* Material developed by Oak Ridge National Laboratory (ORNL) and Bechtel

# Power Demand Forecasts

| | 1986 to 1990 | 1990 to 2000 |
|---|---|---|
| **Percent Annual Growth** | | |
| JEA | 9.7 | 6.0 |
| Meta systems, Hagler/Bailey, and Bechtel National, Inc. | 4.9 | 3.9 |

| | |
|---|---|
| **JEA Peak Demand Growth** | |
| 1980 (actual) | 200 MW |
| 1985 (actual) | 475 MW |
| 1987 (actual) | 593 MW |
| 1995 (forecast) | 900 MW |
| 2005 (forecast) | 1,400 MW |

# JEA Electricity Generating Capacity

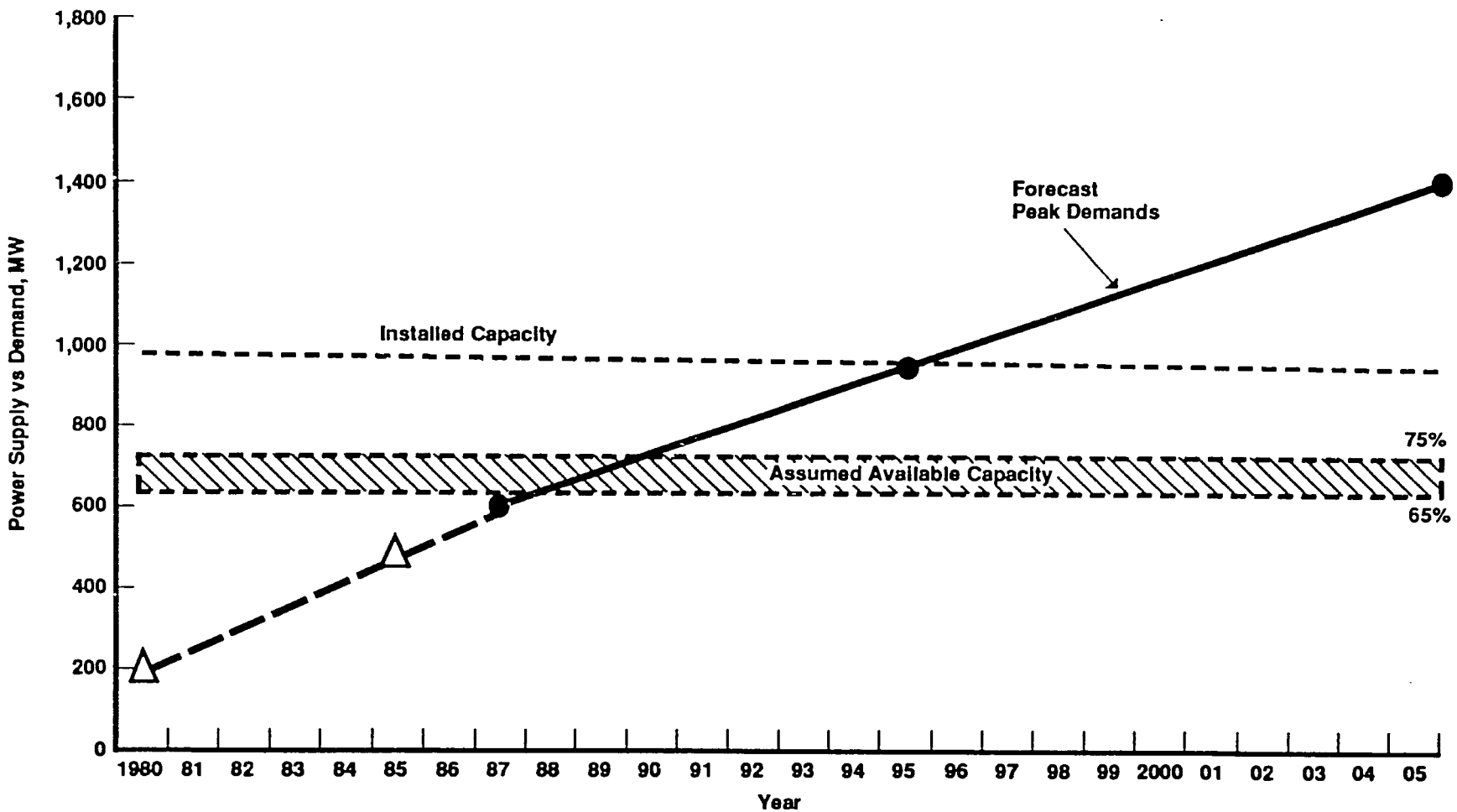
| | 1987 Installed Capacity (MW) |
|---|---|
| Aqaba | 260 |
| | 22 |
| Zarqa | 395 |
| Marka | 102 |
| Karak | 23 |
| Miscellaneous | 67 |
| Subtotal JEA capacity | 869 |
| Other capacity - industrial | 110 |
| Total | 979 |

# Forecast New Power Generating Capacity Required*

| | Fcst Peak Demand (MW) | 1987 Available Capacity (MW) | Shortfall [a] (MW) | Required New Installed Capacity [b] (MW) |
|---|---|---|---|---|
| Assumed capacity factor | | (65%) | | (75%) |
| 1995 requirement | 900 | 636 | 264 | 352 |
| 2005 requirement | 1400 | 636 | 764 | 1019 |

(a) Excludes proposed additions and retirements
(b) Excludes possible power exports or imports
* Load shedding or levelizing not considered

# Supply vs Demand Evaluation




Prefeasibility Study
Oil Shale Fueled Power Generation

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3-14-89 rs/pc:0

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# Conclusions

- Additional power generating capacity is needed to meet forecasted 1995/2005 demand growth
- A 400 MW oil shale-to-power project at Sultani can meet a portion of this need
- A second 400 MW oil shale project may be required if water is available

# *Economic Feasibility* *

- Order-of-magnitude costs
- Economic analysis
  - Jordan study options
  - Project size effect
- Comparison with alternative fuels
  - Fuel requirement
  - Project financing effect
  - Alternate fuel price effect
  - Estimated cost of electricity
- Summary financial analysis

* Material was developed by Bechtel Power Company

# ORDER-OF-MAGNITUDE COSTS

- Oil shale fuel
- Power plant
- Integrated project – busbar

# Oil Shale Fuel Costs *

| | U.S. $1000 | | |
|---|---|---|---|
| | 20 MW | 50 MW | Factored 4x100 MW |
| Installed Capital Cost | | | |
| Mine Development | 4,900 | 7,833 | 30,915 |
| Mine Equipment | 11,090 | 12,202 | 66,012 |
| Processing Plant | 6,945 | 8,388 | 50,889 |
| Spare Parts | 1,200 | 1,300 | 5,000 |
| Working Capital | 1,200 | 2,200 | 10,000 |
| Capitalized Interest | 4,054 | 5,108 | 39,075 |
| Total | 29,389 | 37,031 | 201,891 |
| Annual Operating Cost | 5,582 | 11,556 | 53,236 |
| Fuel Cost, $U.S./tonne | 14.31 | 11.88 | 6.84 |

* Based on 80:20 debt:equity ratio

# Power Plant Costs *

| | U.S. $1000 | | |
|---|---|---|---|
| | 20 MW | 50 MW | 4x100 MW |
| Installed Capital Cost | | | |
| Power facilities | 57,500 | 91,800 | 567,800 |
| Owner's cost | 10,200 | 20,400 | 192,700 |
| Total | 67,700 | 112,200 | 760,500 |
| Annual Operating Cost (excluding fuel cost) | 2,205 | 3,248 | 17,157 |

* Based on 80:20 debt:equity ratio; oil shale fueled

# INTEGRATED PROJECT – BUSBAR COST *

| | U.S. $1000 | | |
|---|---|---|---|
| | 20 MW | 50 MW | 4x100 MW |
| **Installed Capital Costs** | | | |
| Mine & shale processing | 29,359 | 37,031 | 201,891 |
| Power block | 67,700 | 112,200 | 760,500 |
| Waste disposal | 1,664 | 2,381 | 8,714 |
| Infrastructure | 10,000 | 15,000 | 45,000 |
| TOTAL | 108,753 | 166,612 | 1,016,105 |
| **Annual Operating Cost** | | | |
| Mine & shale processing | 5,582 | 11,556 | 56,430(b) |
| Power block | 2,205 | 3,248 | 18,186(b) |
| Waste disposal | 316 | 710 | 6,004 |
| Infrastructure (a) | – | – | – |
| Subtotal | 8,103 | 15,514 | 80,620 |
| Capital Charges, 13.9% | 9,410 | 15,596 | 106,000 |
| Total | 17,513 | 31,110 | 186,620 |
| 25-year levelized cost | – | – | 218,000 |
| **Busbar Cost, mills/kWh** | | | |
| First year | 128 | 92 | 71 |
| 25-year levelized | | | 83 |

(a) Housing and community facilities assumed self-liquidating
(b) Includes first-year inflation adjustment
* Based on 80:20 debt:equity ratio

# ECONOMIC ANALYSIS

- Jordan study options
- Project size effect
- Fuel requirement
- Project financing effect
- Alternative fuel price effect
- Estimated electricity cost
- Summary financial analysis results

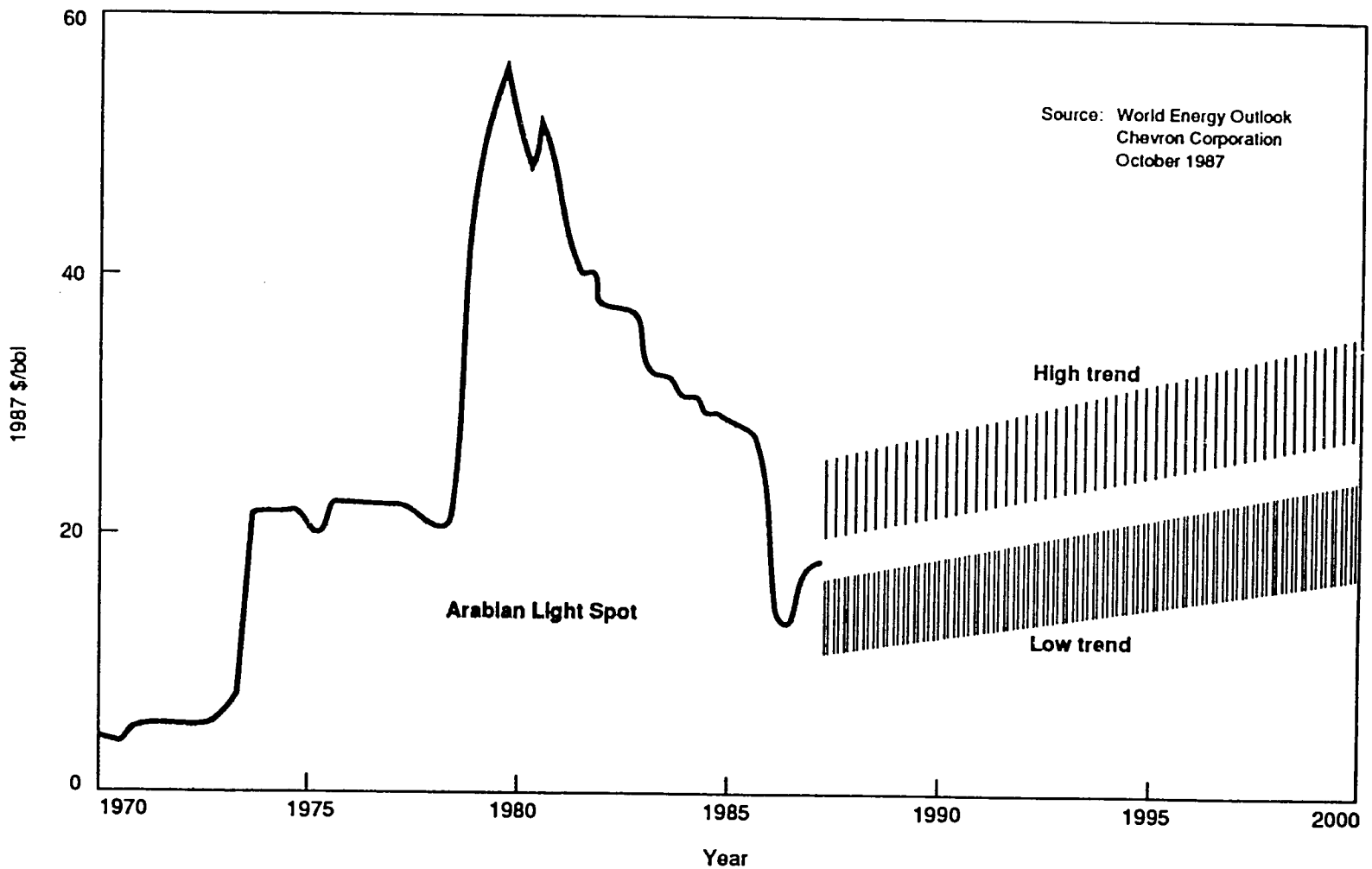
# Jordan Study Options

- Project size
  - Demonstration = 20 MW
  - Prototype = 50 MW
  - Commercial = 400 MW (4x100)
- Project financing
  - Debt:equity 80:20
  - Debt:equity 50:50
- Imported alternative fuels cost assumptions

| | A | B |
|---|---|---|
| Crude oil * | $17/bbl, | $24/bbl, |
| | $120/tonne | $170/tonne |
| Low sulfur coal | $ 50/tonne | $ 70/tonne |

* See Chevron forecast supporting assumptions

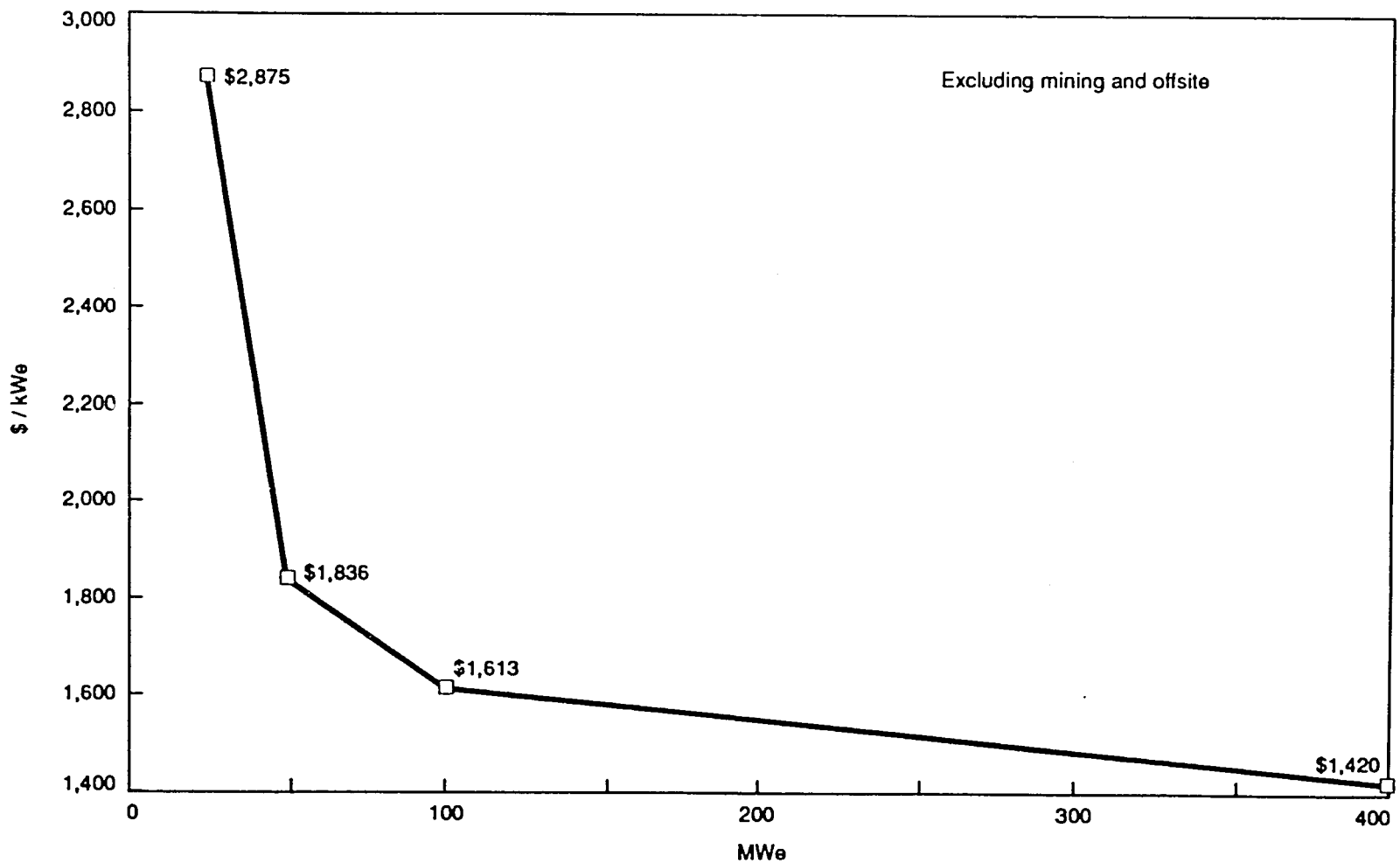
# Crude Oil Price Trends



# Project Size Effect – Shale Fuel Option

| Project Size | 20 MW | 50 MW | 400 MW (4x100) |
|---|---|---|---|
| Integrated facilities installed capital cost, $ U.S. million | 109 | 167 | 1,016 |
| Shale cost, $U.S./tonne (80:20 debt:equity) | 14.3 | 11.8 | 6.8 |
| Cost of power, mills/kWh (80:20 debt:equity ratio) | 128 | 92 | 71 |

# Power Block Investment Cost




August 1988

Prefeasibility Study
Oil Shale Fueled Power Generation

17958/1/47a/Jordan/118
3-14-89 rs/pc:1

# *Fuel Requirement – 4x100 MW Project*

- Coal = 1.2 million tpy
- Oil = 503,000 tpy
- Oil shale = 7.8 million tpy

# Financing Effect – 400 MW Project

| | Capital Cost ($U.S. MM) Debt:Equity 80:20 | 50:50 |
|---|---|---|
| ■ Oil Shale Fuel Option | | |
| Mine and shale processing | 202 | 187 |
| Power block | 760 | 760 |
| Waste disposal | 9 | 8 |
| Community facilities | 45 | 45 |
| Total | 1,016 | 1,000 |
| ■ Coal-Fired Power Plant | 647 | 647 |
| ■ Oil-Fired Power Plant | 463 | 463 |

# Financing Effect – 400 MW Project

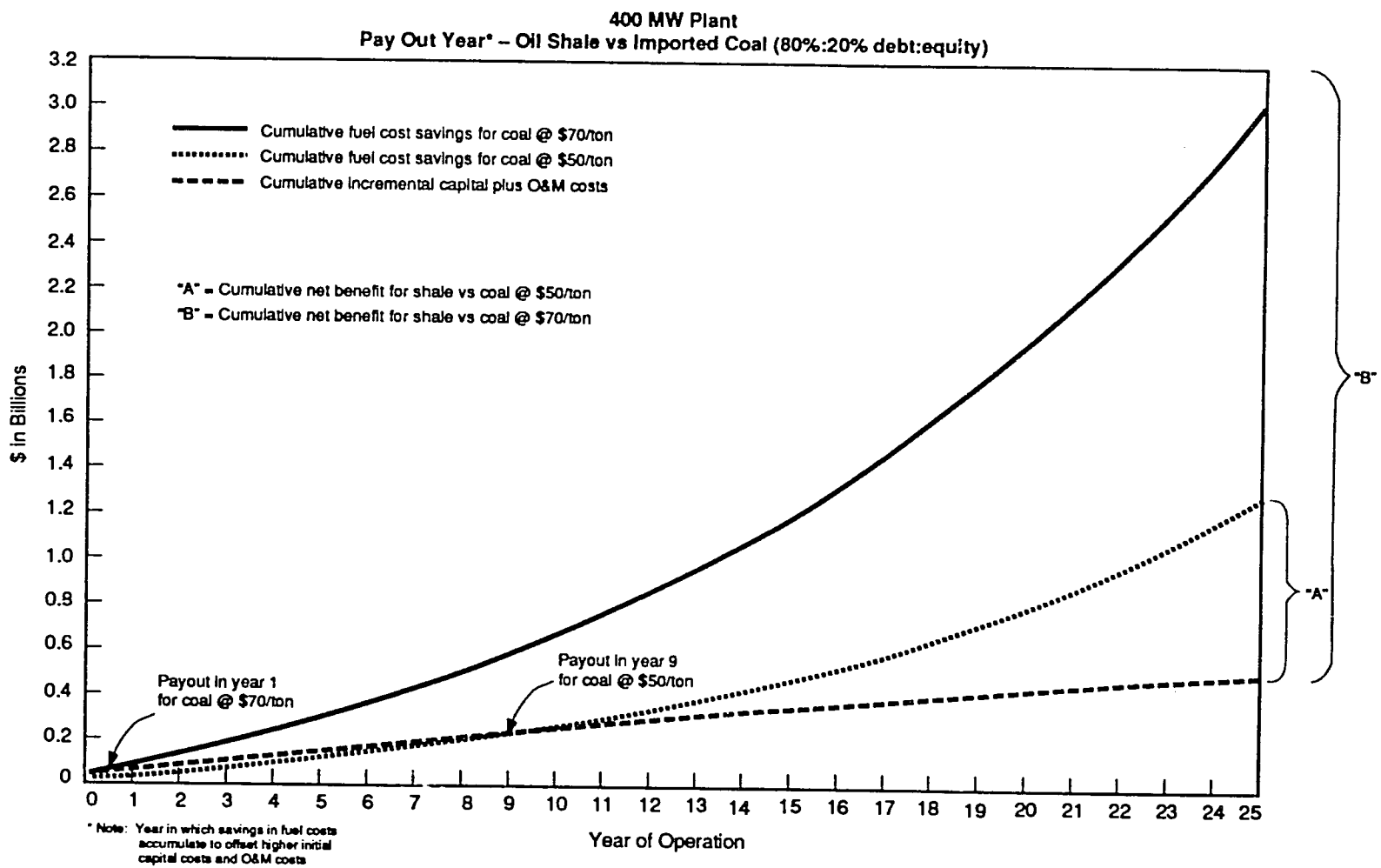
| | Operating Costs* ($U.S. million/yr) Debt:Equity | |
|---|---|---|
| | 80:20 | 50:50 |
| Coal, $70/tonne | 282 | 282 |
| Oil, $24/bbl | 254 | 254 |
| Oil shale-fueled | 218 | 236 |

* Including fuel

# Alternate Fuel Price Effect – 4x100 MW Project

| | Cumulative 25-yr Net Benefit Favoring Oil Shale (U.S. $MM) | |
|---|---|---|
| Financing Basis Debt:Equity Ratio | 80:20 | 50:50 |
| Alternate Fuel Price | | |
| Imported coal | | |
| @ $50/tonne | 778 | 315 |
| @ $70/tonne | 2,531 | 2,068 |
| Imported oil | | |
| @ $17/bbl ($120/tonne) | (18) | (506) |
| @ $24/bbl ($170/tonne) | 1,810 | 1,322 |

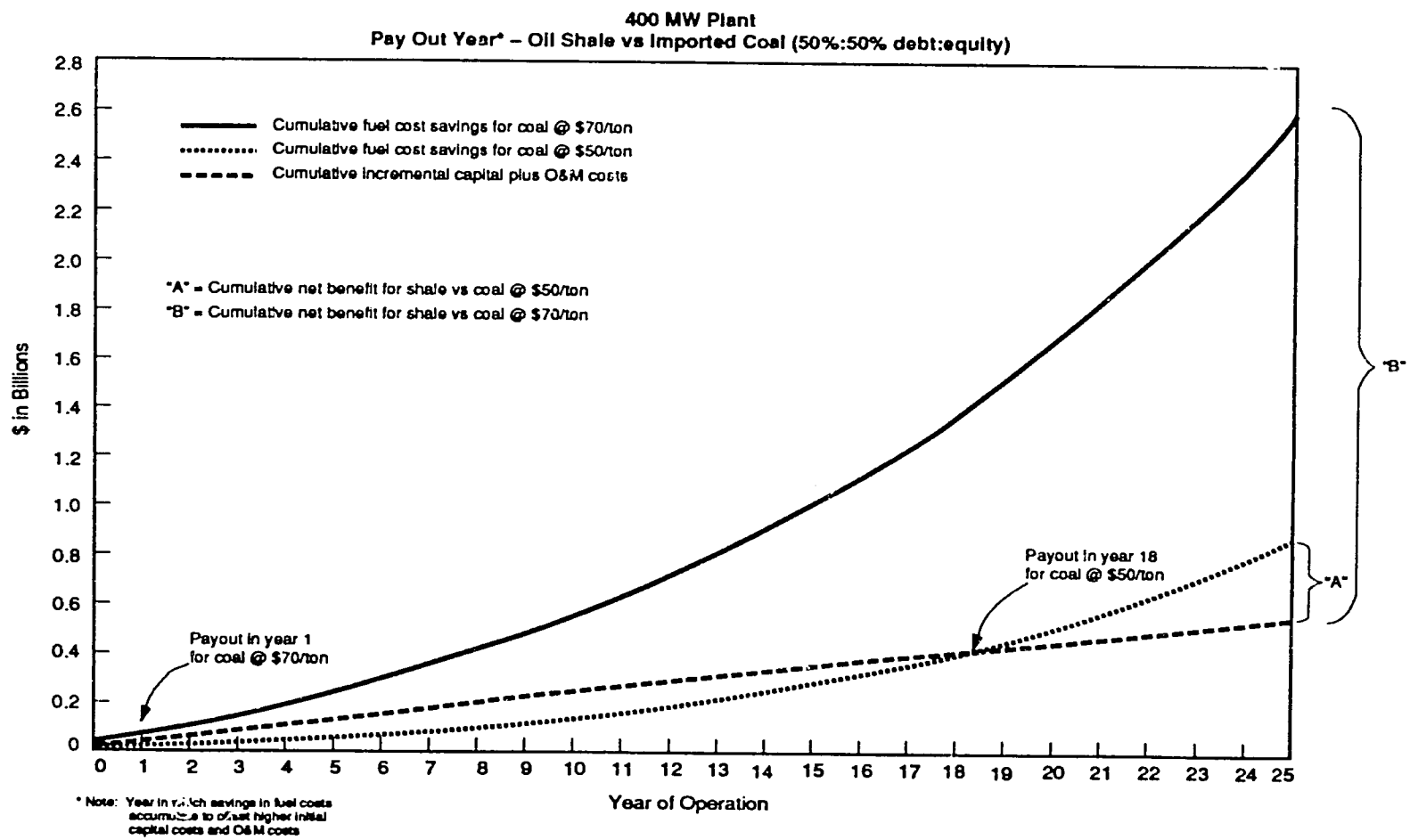
# Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Coal



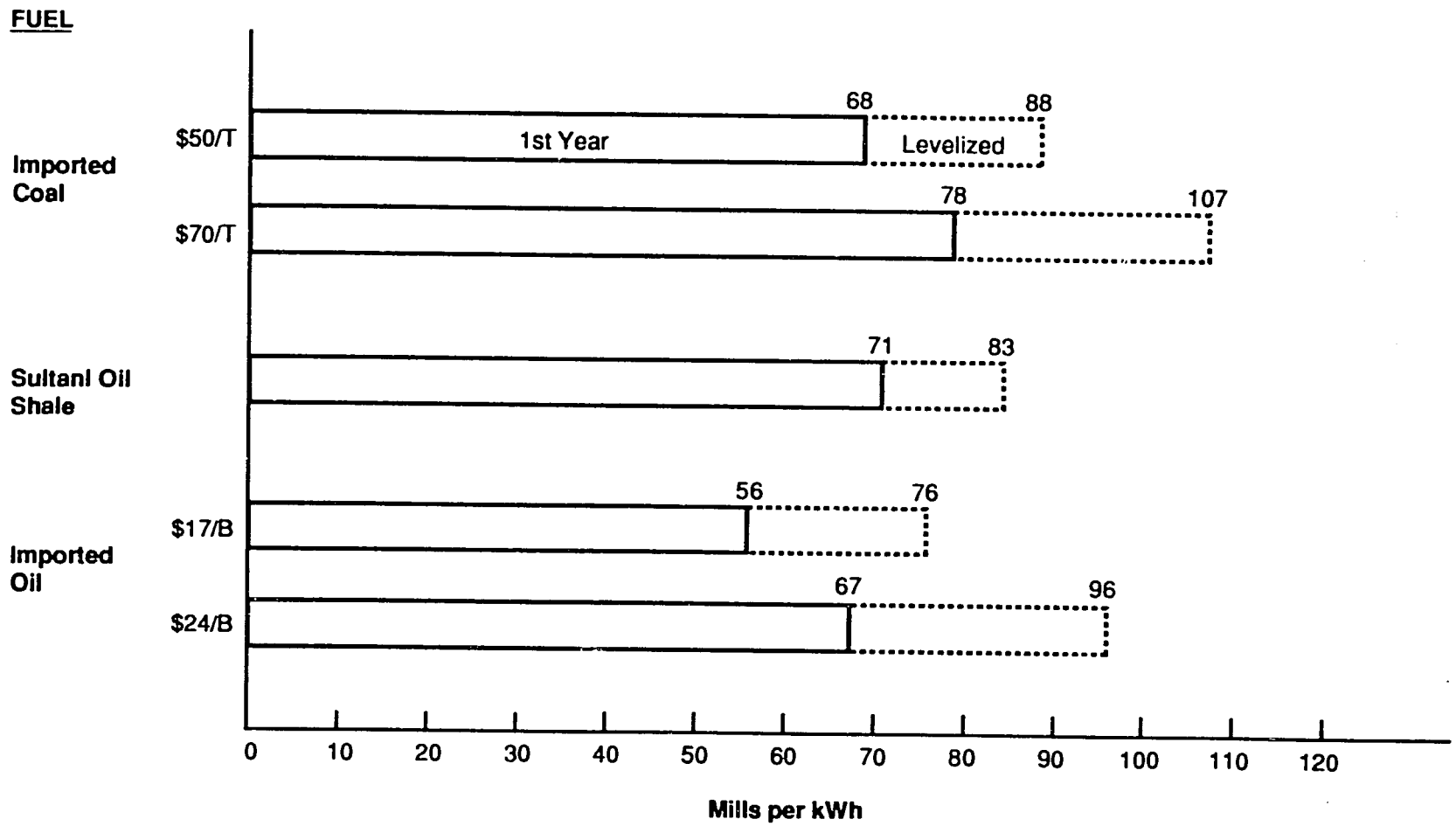

Prefeasibility Study
Oil Shale Fueled Power Generation

17958/3/51a/Jordan/118
3-14-89 rs:0

# Comparison of Cumulative Capital Plus O&M vs Fuel Costs for Oil Shale vs Coal



# Estimated Cost of Power – 400 MW (4 x 100)




Prefeasibility Study
Oil Shale Fueled Power Generation

17958/12/51c/Jordan/118
3-14-89 rs/pc:1

# Summary Financial Analysis Results

| | Economic Comparison |
|---|---|
| Project size | Very significant |
| Debt: equity ratio | |
| – Investment cost | Not significant |
| – Power cost | Not significant |
| – 25-year net benefit | Very significant |
| – Project implementation | Critical |
| Alternative fuel price | Very significant |

# Study Conclusions

- Feasibility
- Timeliness
- Expansion conditions
- Environmental impacts
- Development advantages

# *Feasibility*

Oil shale fueled power generation is technically and economically justified under certain conditions

- Need for additional generating capacity exists
  - 6% annual peak demand growth
  - Orderly retirement of older/high cost generating capacity needed
- Higher costs are expected for imported fuels
  - Coal/oil prices will be at least 15% greater after 1995
  - Discovery of indigenous conventional fuel resources is inadequate for power plant purposes

## *Feasibility (Cont'd)*

- Suitable financing will be available
  - For $200 million 50 MW prototype project
  - For $1,000 million 400 MW commercial project
- Government of Jordan will make basic commitments
  - Long-term power purchase agreement
  - Long-term access to Sultani shale deposit
  - Adequate water and manpower resources
  - Attractive tax incentives

# Timeliness

- Timely development of Jordan oil shale needs prompt action to create
  - Additional definitive information
  - Suitable business plan

# Expansion Conditions

- Continued expansion of power generation from oil shale in Jordan depends on water availability

- Prospects for power export or import and domestic load growth will affect size of the needed shale-to-power program

# Environmental Impacts

- Environmental impacts of shale development will be minimal

# Development Advantages

- Will create significant new job opportunities in Jordan
- Will avoid/reduce foreign exchange losses for expanding alternate fuel imports

# Recommended Action Plan

- Basic recommendation
- Conceptual development schedule
- Project development plan
- Key plan elements
- Funding requirements

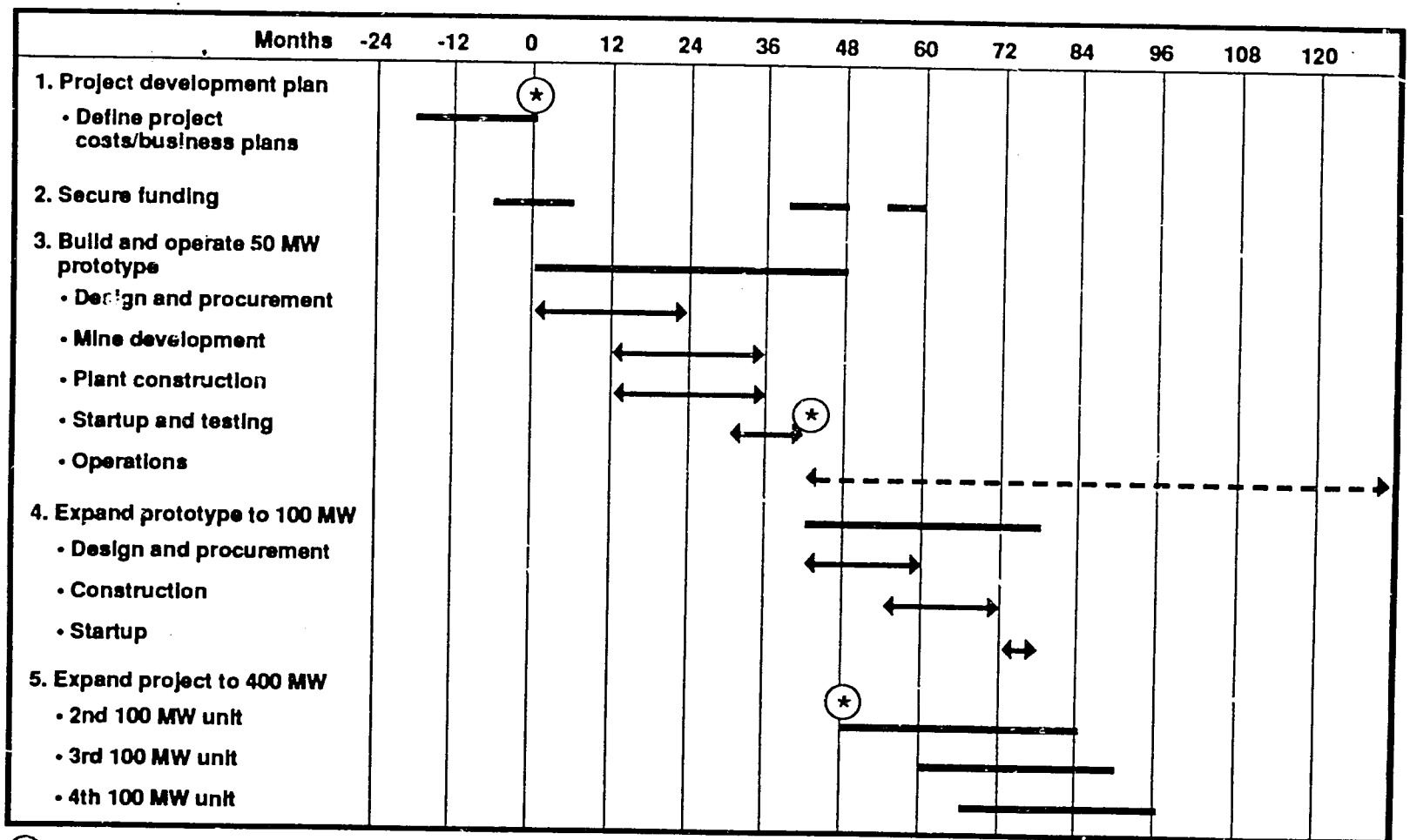
# Basic Recommendation

- Expand efforts to develop an oil shale-fueled power generation program at the Sultani deposit
  - Conduct required supporting studies
  - Define facilities costs and business plans
  - Obtain project funding

# *Conceptual Development Schedule*

- 1989-1990
  - Conduct supporting studies
  - Define costs/business plans for 50 MW prototype and 400 MW commercial projects
  - Develop project financing
- 1990-1993 – Build and operate the prototype project
- 1994-1996 – Expand the 50 MW prototype to 100 MW scale
- 1996-2000 – Expand the project to 400 MW scale
- 2000-2005 – Build a second 400 MW commercial project if needed

# Conceptual Development Plan




(*) Project decision point

# *Phase I – Project Development Plan*

- Program development
  - Seminar workshop on prefeasibility study
  - Create project development plan, work scope, schedule, and budget
- Carry out project planning program
  - Conduct continuing support studies
  - Test Sultani shale in existing FBC
  - Firm up designs and specifications
  - Update costs and economic analysis
  - Develop business plans and requirements
- Explore project funding alternatives

# Key Plan Elements

- Project feasibility analysis
  - Firm up designs and equipment specifications for all facilities
  - Update cost estimates based on preliminary designs and specifications
  - Explore arrangements for contract mining and mine development
  - Update forecasts for demand growth and for retirements of older generating capacity
  - Create updated economic analysis

# Key Plan Elements (Cont'd)

- Business entity requirement
  - Explore options/conditions for a new company to manage/build/operate the project
  - Explore options/conditions for obtaining a concession agreement for Sultani development
  - Explore options/conditions for water rights commitment

# Key Plan Elements (Cont'd)

- Continuing supporting studies
  - Combustion tests (additional pilot tests for design and warranty purposes; contract for large-scale burn operations in existing plants if appropriate)
  - Additional core drilling and core analysis
  - Oil shale crushing tests
  - Spent ash leaching tests
  - Geotechnical data base including soils analysis
  - Environmental baseline data

# Steps Required to Develop an Oil Shale-to-Power Project

- Create a development business plan
  - Schedule
  - Decision tree
- Develop a work scope and budget for the development plan program including
  - Firming up designs/specifications/costs
  - Developing business entity requirements
  - Continuing support studies
- Carry out development plan program
- Assemble all planning results in a report for discussion with financial institutions
- Explore project finance opportunities
- Finalize business arrangements
- Implement prototype project

MARCH 15 JEA QUESTIONS (M. S. ARAFAH) ON PREFEASIBILITY STUDY DRAFT REPORT

بسم الله الرحمن الرحيم

JORDAN ELECTRICITY AUTHORITY

سلطة الكهرباء الاردنية

Ref. : 5/8/7 \ 6827

Date : 15/3/1989

الرقم :

التاريخ :

MR. JAMES B. SULLIVAN, PH.D.
DIRECTOR
OFFICE OF ENERGY
BUREAU FOR SCIENCE AND TECHNOLOGY
AGENCY FOR INTERNATIONAL DEVELOPMENT
WASHINGTON. D.C. 20523
U.S.A.

SUBJECT:- **COMMENTS ON OIL SHALE TO POWER PREFEASIBILITY STUDY DRAFT REPORT**

Dear Mr. Sullivan ,

We refer to your letter dated Jan. 9/1989 regarding comments prepared by concerned Jordanian departments on your report. Please find below our comments:-

1- **FINANCIAL AND ECONOMIC COMMENTS** :-

1.1- Vol.1 page 1-11 section 1.04
It is indicated that Bechtel and US.AID/Washington are recommending that JEA should undertake the next phase of this resource development program in order to create definitive design and budget cost estimates.

Also the study indicates that substantial subsidies will be needed for either a 20 MW demo. Plant or the 50 MW prototype plant. Therefore JEA is anxious that either demo plant or prototype projects should be approached on a Build, Operate and Transfer (BOT) arrangement. The manufacturer or contractor involvement in investment under a BOT or similar arrangement is essential and that JEA shall buy whatever electricity generated at the same average price of JEA generation cost in order to assess the technical and economic prospects for an oil shale power generation projects in Jordan.

1.2- Page 1-12
It is suggested that option 1 of the action plans is to contract with owners of existing (or under construction) CFB combustors to test large tonnage quantities of Sultani oil shale for several months of sustained operation. However, JEA prefers that the pilot or the demo plant is to be installed and

operated in Jordan in order to gain enough experience on mining, crushing and handling of oil shale and ash material and also on CFB boilers and to get enough data needed for design of large scale CEB boiler in accordance with Jordanian oil shale quality and site requirements instead of shipping a large tonnage of oil shale .

1.3- Table 1-2 page 1-7 "Cost of Power ".
It is mentioned that the commercial oil shale project (4 X100 MW) is in a competitive cost range, while table 1-2 indicates that cost of power is 71 mills/ kwh which is still much higher than the average cost of power generation from JEA thermal power stations .Please indicate on what basis you have made your statement.

1.4- Page 4-21- Section 4-05
It is unlikely that the off- site infrastructur (housing and community facilities) to be considered for both the demo.and prototype projects.Moreover,we think that their cost is rather high .

1.5- Page 4-11 Mine Operation
It is indicated that mining costs received from the mine contractor are incomplete, and you did not consider contract mining option for the prefeasibility study .Please note that the contract mining costs are real and represent the real costs derived from phosphate mining contractors in Jordan.We recommend that you should consider them at least for the demo. or prototype plants in order to reduce the capital and fuel costs.
Please note that due to the new exchange rate of the Jordanian Dinner,you may add 20% to the quoted contract mining costs.

1.6- Please consider the following recent changes:-

1.7.1- The new exchange rate of USD=540 fils.
1.7.2- The new average tariff for selling electricity has decreased to 20.8 fils/kwh.

1.7- Page 1-7 Table 1-2
We believe that the capital costs for the power block and for the mining and ash handling equipment

are very high. We suggest that you reconsider capital cost and use lower accuracy estimate range than ± 30%.

1.8- Page 4-22 Table 4-5
We noticed that Pyropower has added extra capital cost for the boilers and that adjustment is only for Jordan location. Please clarify and indicate the adjusted percentage for construction in Jordan.

1.9- Page 1-7 Table 1-2
You have used higher interest rate on Equity than on Debt. Please include a detailed explanation of this criteria, keeping in mind that JEA is a non profit organization, unlike other private USA utility installations.

1.10- Regarding the capital cost of the project, it is requested to break it into foreign and local costs. Meanwhile, the interest should be considered on the foreign portion only and not on the local portion.

1.11- Page 4-23
We think that allowance of 15% as a project contingency is too high, a lower value should be considered.

1.12- Tables 8-1 - 8-8 include the calculations of cumulative net benefits for different generating unit types. It is more likely to calculate the net present value for the benefits in different alternatives to assess the feasibility of oil shale alternative.

1.13- Page 4-26
We agree with you that the percentage used for the annual O & M is rather low and a somewhat higher rate may be needed for a CFB plant. Meanwhile page 4-29 indicates that the estimated variable maintenance costs in addition to the fixed maintenance costs is 1 mil/kwh. We think that this is too low.

1.14- Page 4-29
Fuel (oil shale) costs are additional variable operation costs. The oil shale costs include both

mining cost and crushing /handling costs. Have you considered the additional royalty cost mentioned in Vol .II which is 100 fils/ Ton ? And what do you mean by return on royalty (4-8).

1.15- Page 4-31
It is indicated that an approximate 15% capital charge used for the power block facilities is typical of the capital charge rate for many USA utility installations , while on page 6-19 table 6-9 it is mentioned that the capital rate per JEA is 15%. Please Justify this matter since we did not recall giving you this number .

1.16- Page 6-16
It is mentioned that the costs of process water are 0.2$/1000 gallons .
Have you considered additional value of buying water from the Water Authority ? or additional cost for reverse osmoses plant if ground water is used ?

1.17- Table 6-1 page 6-6
Please explain how did you come out with the oil shale mining and processing unit cost.

1.18- Please note that the average JEA production cost from thermal power stations (station bus-bar cost) is between 16.3-17.3 fils/ kwh .You may use this figure for comparison purposes.

1.19- For 4 X 100 M.W. Plants ,it is mentioned on page 14-4 Vol II that at total of 424 employees will be employed and on page 6-9 Vol I it is mentioned that a total of 1046 employees will be employed, please clarify this matter .The integrated project staffing requirement is high as it exceeds 1000 persons for the 4 X100 MW plant.

1.20- Page 4-25
The following items are assumed to be excluded from the capital cost :-

1.20-1 Permits & licenses .
1:20-2 Local taxes .
1.20-3 Import taxes on spare parts and consumable materials.

All fees, taxes in accordance with the Jordan laws and regulations should be considered .

1.21- please indicate your justification for using a 6% inflation rate .

1.22- Table 9.7 App.5 Page 9-14
It is clearly indicated that the IRR of the 400 MW plant is rather unattractive (6.6) when considering the most logical base case (capacity factor 60% average selling price 6 C/kwh & D/E ratio 80/20% ). Moreover the new selling price for JEA at the time being does not exceed 4 C/kwh .However page 1-10 and 10-5 indicate that economics for a commercial scale oil shale project appear promising enough to warrant continued development of a full scale feasibility study which will cost several million dollars. Please make clear wether the next step is to be considered according to the unattractive IRR results mentioned in Table 9.7 .

2- **TECHNICAL COMMENTS** :-

2.1- Page 1-6 Table 1.1
We noticed that the water requirement for the 4X100 MW units is rather low when compared with the water requirement for the 50 MW prototype plant.Please give detailed clear figures of raw water consumption for each of 20 M.W ,50 M.W and 4X100 MW plants, showing power plant water make up, housing complex consumption,mine and ash wetting ... etc.

2.2- page 2-11 APP. 5.
You have assumed that the spent shale is non-toxic and no special measures are required to protect the ground water from being contaminated, while referring to APP.6 page 7-21 which indicates that based on the results of EP-TOX leaching of fly ash could result in concentrations of chromium ,selenium and arsenic and some dilution of these elevated levels could be expected as ground water migrates away from the disposal site and disposal of ash below or near the ground water table could degrade ground water quality. please clarify .

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2.3- Page 2-4
It is indicated that the oil shale resources in Jordan are 10 billion tons. The actual proven reserves may exceed 50 billion tons .

2.4- Page 2-11
We believe that CFB combustion temp is high and also it may lead to thermal loss due to calcium carbonate decomposition.

2.5- Page 4-16
Please indicate your procedure to cool the bottom ash and at what discharged temperature.?
Have you considered additional heat exchanger to cool the ash and to improve the cycle efficiency which is low ?

2.6- Page 4-16
It is indicated that ash from each silo is mixed with about 20% water by weight to minimize generation of dust during transportation to mine and disposal.Have you considered other alternative to eliminate dusting and avoid use of water during transportation such as using closed trucks or closed belt conveyers instead ?

2.7- Page 4-12 Section 4.04.2
Please clarify why specific studies have not been made to select an optimum cycle for the plants .

2.8-Page 4-18 Section 4.04.9
Please note that JEA practice is to deliver power to the high voltage transmission system through a main start-up transformer rated 22-132Kv and not through 22-400 Kv.

2.9- Page 4-19
JEA practice is to protect the generator by utilizing generator breaker rated 3000 A,1000 MVA .

2.10- DRW E- 101 A
It is not clearly described how the power generation is connected to the 132KV system . We recommend that the generator main transformer to have a higher capacity as the plant will be running as a base load.

بسم الله الرحمن الرحيم

JORDAN ELECTRICITY AUTHORITY

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2.11- Page 4-15 section 4.04-5
It is indicated that the unit output should be reduced if the condenser pressure rises above 9 inches Hg during high ambient temperature. We believe that the plant should be designed to meet the max. ambient temp.

2.12- Please provide us with the gross and net generating capacity for the three options .

2.13- It is indicated that the disadvantage of CFB is the heavy fans power consumption. Please provide us with the percentage of fans consumption with relation to the total plant auxiliary power consumption.

2.14- Table 5-3 and 1.1
There is some contradiction regarding plant net output in both a/m tables.

2.15- Table 1-3
We noticed that all your calculations are based on capacity factor of 75% . We think that 75% capacity factor is too high for an oil shale fired plant due to lack of existing similar plants handling and firing oil shale .

2.16- The study indicates that a wet cooling tower will be used. Actually a dry cooling should be considered as in H.T.P.S. in Zerqa to minimize water consumption so the cycle efficiency will be reduced. Hence you reconsider calculating the cycle efficiency.

2.17- Condensate pumps of horizontal type are considered, the the vertical can type can also be considered.

2.18- A concrete shell, steel flue stack is considered . The concrete shell, brick flue stack can also be considered.

2-19- Deminiralized water tank capacity is 76 cubic meter. The recommended tank capacity is 1000 cubic meter.

2.20- Design conditions page (4-4) ,
States that blow down percentage is (1%), from practice it should be (3%) .

بسم الله الرحمن الرحيم

JORDAN ELECTRICITY AUTHORITY

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2.21- Section (13) page 13-3) ,
States that the quantity of ash is 1000 Tons/hr and this quantity will be transported for several years to out of pit waste storage located 4 K.M. from power plant.So about 12 million cubic meter/year will be dumped and in two years time the dumping

area will be very close to power plant .Please make alternative study for dumping the ash far enough from the power plant .

2.22- Please provide detailed information about heat balance drawing showing T.H.R, U.H.R. and plant heat rate taking into consideration the auxiliary consumption including the mining equipment .

2.23- It is noted on page (4-4) volume (1) of (11) that mine operation is 3 shift /day .Please make alternate study of mine operation for 1 shift/day and two shifts /day .

2.24- Conceptual plan for mining ,crushing and transportation of oil shale handling ,cooling and dumping of spent shale should be further examined in order to prove technical and economical feasibility of this operation.

Your are requested to study and consider all above points at your earliest in order to be presented by you in Amman on March 29-30,1989 .

Sincerely Yours

M. S. ARAFAH
DIRECTOR GENERAL

CC. MR. W. LINTON
PROJECT MANAGER

CC. MR. R. BUTA
MANAGER

P.o. Box 2310. Amman - Jordan - Tel 815615-20 817615-19 ٢٣١٠ _ عمان _ الاردن _ تلفون ٢٠ _ ٨١٥٦١٥/١٩ _ ٨١٧٦١٥

MARCH 21 RESPONSE TO JEA QUESTIONS

Bechtel Power Corporation
Engineers – Constructors

Fifty Beale Street
San Francisco, California
*Mail Address:* P. O. Box 3965, San Francisco, CA 94119

March 21, 1989

Mr. M. S. Arafah
Director General
Jordan Electricity Authority
P.O. Box 2310
Amman, Jordan

Subject: Jordan Oil Shale Prefeasibility Study

Dear Mr. Arafah:

Your letter of 15 March 1989 with comments on the Oil Shale to Power Prefeasibility Study draft report has been referred to me for reply.

The attached responses to each item in the reference letter follows the order submitted.

Also, attached are three revised pages for the draft report - Volume I.

Page 6-1
Page 6-21
Page 6-23

Please copy these revised pages into the report previously sent to you.

We plan to review this material with JEA during the March 29/30 and April 1 meetings in Amman.

Very truly yours,

W. H. Linton
Project Manager

WHL:dc

Attachments: Questionnaire Response
Three revised pages

cc: C. J. Aulisio
R. R. Buta
G. D. Gould
T. J. Wilbanks

# RESPONSE TO MARCH 15, 1989 QUESTIONAIRE
# OIL SHALE TO POWER PREFEASIBILITY STUDY

This study examines economic prospects in terms of a 1995-2000 timeframe.

## FINANCIAL AND ECONOMIC COMMENTS

1.1 It is likely that a BOT deal can be structured at present JEA generation costs for either 20 MW or 50 MW size units if GOJ is willing to subsidize the incremental power generation cost. Furthermore these incremental costs can be recovered during the 25 year operation of a Commercial Scale Project.

1.2 A 3rd Party Test was proposed as an alternate means to raising $100+ for an independent JEA sponsored 20 MW Demonstration program.

1.3 71 mills/KWH for Shale Power

vs.

JEA 1987 costs

| | | | |
|---|---|---|---|
| Purchased Power | 17 fils/KWH | = | 51 mills |
| Produced Power | 1360 fils/KWH | = | 41 mills |

1995/2000 Costs - Expected to be 30 to 40% higher and in line with the cost estimate presented in this study.

It also is important to recognize that the busbar cost of power generated by any new power source can not be compared directly with the cost of existing older installed capacity because of the lower capital cost component of the latter. (See enclosed Figure 1-1 which demonstrates how total capital carrying costs decline as the investment is paid off.) Any new capacity whether coal, oil, or oil shale will be an unreasonable disadvantage compared with costs for existing older capacity.

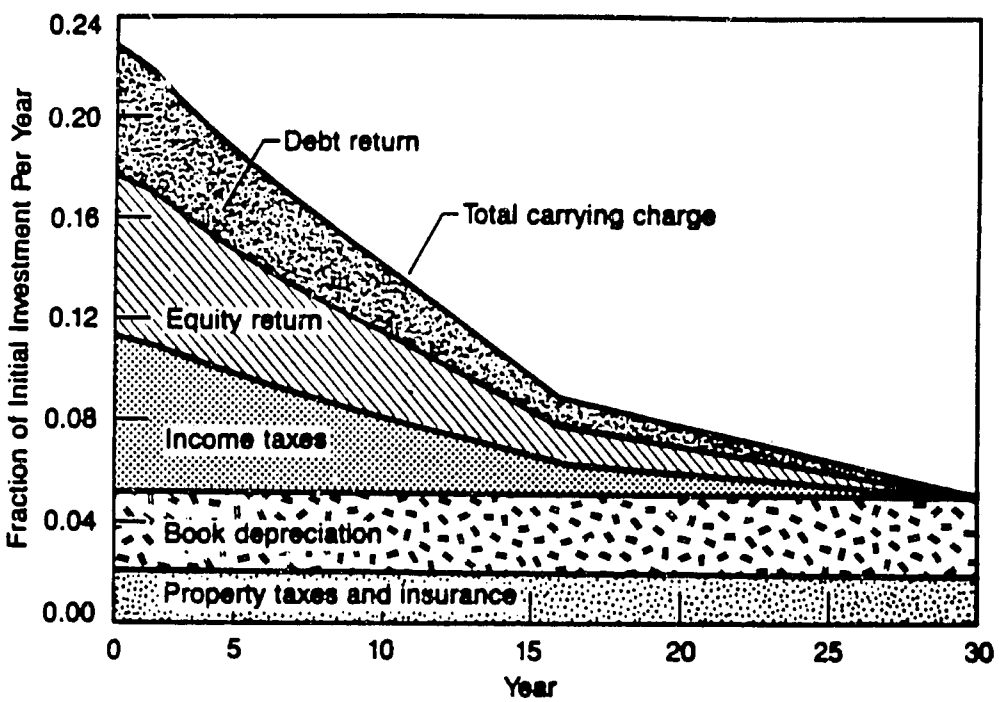


Figure 1-1. Year-by-year Carrying Charge Components for 15-year Tax Recovery Period



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1.4 Infrastructure Cost

| | | Total People Operator/Families | Installed Cost |
|---|---|---|---|
| 20 MW | $10,000,000 | 185/700 | $54,000/Operator |
| 50 MW | 15,000,000 | 324/1200 | 46,000/Operator |
| 400 MW | 45,000,000 | 1036/4000 | 43,000/Operator |

Factored allowance for grass roots desert installation including housing and community facilities was developed as follows for the 50 MW case study.

Infrastructure

50 MW

| | | |
|---|---|---|
| Family Housing 200 @ 30K | = | $ 6 Million |
| Bachelor Housing 100 @ 20K | = | 2 M |
| Hospital/Clinic (8 Beds) | = | 1 M |
| School/Mosque | = | 1 M |
| Stores, Services & Recreation Facilities | = | 2 M |
| Roads, Electricity, Water, Sewage | = | 3 M |
| | | $15 Million |

Infrastructure costs for the 20 MW and 400 MW cases was ratioed from this breakdown.

At this conceptual level costs are order-of-magnitude. In a Phase II program these infrastructure costs can be developed in detail.

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1.5 Contract Mining Alternatives
Page 4-11 Mine Operation
Based on Bechtel's evaluation of the mine contractors price, as found in Section 15 of the Mining Report, it was concluded that the mine contractors price does not include costs for such things as: developing the mine with a box-cut, ramp, haul roads, developing an area for the waste material, maintaining the haulroads, constructing the mine services facilities, diversion ditches, sedimentation ponds, water well, crushing the oil shale, pre-mixing the oil shale at the mine and other items associated with operating a mine to support a power plant. If it is proven that the mine contractors price includes cost for the above mentioned scope of work in addition to drill, blast, load and haul, then the contractors price can be used, but in the meantime, the all inclusive cost developed by Bechtel should be used.

Contract Mining appears to be attractive for the smaller size plants but not for the larger commercial scale operation. Some third party must provide the necessary capital for trucks, loading, mining machines, etc. under a contract arrangement.

1.6 Reassessment due to Dinar value change needs further study and can not be evaluated given present budget limitations. If average labor rate of $3.00/hr still valid then little change involve with study.

If deemed necessary, reexamination of project economics can be done in Phase II when funded.

1.7 Costs in this study are based on recent similar Bechtel experience on Mount Poso project and on Montana I project. The Mount Poso project is a 50 MW unit firing coal in a Pyropower boiler. The Montana I project is a 35 MW unit firing coal in a Keeler Dorr Oliver FBC boiler utilizing dry cooling.

1.8 The Pyropower quote of $186,000,000 to furnish and erect the steam generator, stack and baghouse has been adjusted to include engineering, construction indirect cost, etc. to be consistant with the rest of the costs shown in Table 6.5, p. 6-10. No further adjustment for location was made.

1.9 Equity funding has the lowest priority of payoff in case of a liquidation and carries greater risk. Hence a higher rate of return is needed to attract these funds. Debt funding is a first mortgage and has first priority for payoff in case of liquidation and carries less risk. Hence it requires lower rate of return than equity funding.

The "risk taking" equity owner will ask for greater interest rate to make funds available. The only way to minimize this expense is to find a loaning agency willing to provide 90% or perhaps 95% of the investment cost. It is likely that banks will require some minimum equity participation.

This Prefeasibility Study was not based on a non-profit utility operation.

Even though JEA is a non-profit organization, its service contributors are profit making groups. It is visualized that the Jordan Oil Shale Co. (JOSCO) will be a stand alone business enterprise servicing JEA under long term contract. To secure funding for the proposed project, JOSCO will need attractive enough contract terms to attract both equity and debt capital.

1.10 Additional work is needed to develop the requested information. This work can be preformed as part of the Phase II program.

1.11 Bechtel includes contingency in all of its estimates to cover error, emissions and unforeseen items within the defined scope of the project. The level of contingency is dependent upon the amount of scope definition. For a prefeasible study such as this, 15% contingency is lower than normal.

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1.12 Tables 8.9 through 8.16 include a present value calculation to establish the relative benefit for a shale project vs. coal and oil.

1.13 The variable maintenance cost of 1 mills/KWH has been adjusted for CFB plants with an additional $200,000 per year or 0.6 mills/KWH.

This yields the following:

| | | |
|---|---|---|
| Variable Maintenance | - | 1.0 mills/KWH |
| CFB Adjustment | - | 0.6 |
| Fixed Maintenance Cost | - | 4.0 |
| Total Cost: | | 5.6 Mills/KWH |

1.14 Page 4-29
The royalty costs are included in the weighted average oil shale costs for the 50 megawatt plant.

Page 4-8
Shale fuel costs include return on equity, and royalty. These are two separate cost items. Royalty is the last item mentioned in the sentence and it therefore, reads as royalty and not return on royalty.

Page 4-31 gives rates used by Bechtel based on our calculations using the referenced procedures:

| Debt/Equity | Capital Charge Rate |
|---|---|
| 50/50 | 15.3 |
| 80/20 | 13.9 |

Table 6.9 displays the calculation of the 15.3% capital charge rate (Line 7 of Table 6.9 is not used in the calculation and should be deleted.)

1.16 No water purchase charge from the Water Authority was added to the operating expense based on the statement that no resource costs will be charged.

$0.20 per 1000 gallons is rule of thumb for USA installations in absence of client data.

Boiler make up water (p.4-17) is treated in a demineralizer train. If deemed necessary comparison with reverse osmosis process can be performed in Phase II.

Water requirements were estimated to be:

| | Cubic Metres Per Year | | |
|---|---|---|---|
| | 20 MW | 50 MW | 400 MW |
| Mine & Shale Processing | 455,000 | 761,000 | 773,000 |
| Power Block | 3,000 | 6,000 | 42,000 |
| Infrastructure | 80,000 | 140,000 | 448,000 |
| Total | 538,000 | 907,000 | 1,263,000 |

1.17 Annual average operating costs shown on Table 6-1 are in error:

| Financing Option | 50/50 | 80/20 |
|---|---|---|
| Cost Shown: | 56,606 | 48,945 |
| Corrected Cost: | 60,396 | 53,236 |

Average mining and shale processing costs are developed year by year in the Mining Report Appendix 5 Table 12-10.

1.18 We would be interested in receiving the breakdown of these current power cost figures (i.e. capital charges, fuel cost, number of operators, etc.). Further economic analysis employing these figures can be developed in Phase II.

1.19 Manpower requirements for the three case studies were estimated as follows:

| | 20 MW | 50 MW | 400 MW |
|---|---|---|---|
| Mining & Shale Processing | 75 | 163 | 396 |
| Power Block | | | |
| Operations | 54 | 78 | 175 |
| Maintenance | 46 | 73 | 455 |
| Management | 10 | 10 | 10 |
| | 185 | 324 | 1036 |

Page 14-4 of the Mine Report is for mine and shale processing only. It should be noted that most of these manpower requirements involved new jobs for Jordanian people.

1.20 At the April 1988 Amman Meeting it was agreed that the following costs would be omitted:

- o Permits and Licenses
- o Local Taxes
- o Import Taxes

If necessary such costs can be developed and added into a revised economic analysis as part of the Phase II program.

1.21 6% average inflation rate is the figure recommended by Bechtel based on USA conditions for use in long term economic analyses of new power ventures.

1.22 This matter is referred to ORNL who prepared a rate of return analysis.

Bechtel's conclusion is based on computed busbar costs/cumulative benefits compared to alternate fuels in the timeframe 1995 to 2000:

| | Relative Busbar Power Cost Mills per KWH | Net 25 Year Benefits - Million US$ |
|---|---|---|
| Sultani Oil Shale | 71-83 | Base Cost |
| Imported Coal | | |
| @ $50/tonne | 68-88 | 778 |
| @ $70/tonne | 78-107 | 2,531 |
| Imported Oil | | |
| @ $17/Bbl | 56-76 | (18) |
| @ $24/Bbl | 61-96 | 1,810 |

The above results are based on a capacity factor of 75%, which is considered to be a reasonable target for a new plant over its 25 year life. The average selling price of 6 cents per KWH, cited in the questionnaire, is based on existing plant costs which may not include all cost elements of new capacity evaluated in this study.

TECHNICAL COMMENTS

2.1 See answer to Item 1.16

Total power plant raw water consumption rates and annual consumptions including the water requirements for wetting ash at the truck loading point within the power plant are given in Tables 4.3 and 4.4 for 50 MW unit and Tables 5.3 and 5.4 for 20 MW unit. The raw water requirements for 4x100 MW plant were factored excepting the mine where a revised mine plan is employed to reduce water request. The quantities shown on these tables exclude raw water requirements for housing complex, mine and ash wetting, if required, at the ash disposal site.

Total power plant requirements shown in the above referred tables are:

| | 50 MW | 20 MW |
|---|---|---|
| Rate, gpm | 207 | 102 (See Drawing M.004) |
| Annual Use | | |
| Gallons | 1,400,000 | 675,000 " " |

Cooling tower blowndown, supplemented with raw water is used for wetting ash at the truck loading point within the power plant. Raw water quantities attributable for ash wetting at the power truck loading point are;

| | 50 MW | 20 MW |
|---|---|---|
| Rate, gpm | 75* | 32.5* |
| Annual Use | | |
| Gallons | 500,000* | 215,000* |

*These quantities are included in the quantities shown in the above referred tables.

2.2 We recognize the POTENTIAL for leaching toxic compounds from the spent ash. However this matter is not yet defined well enough to recommend specific action steps. The Prefeasibility Study, page 7-12 recommends creation of a ground water dispersion model to determine whether more specific contaminated water mitigation plans are needed. It is anticipated that the leachate rate will be low and that aquifer dispersion will keep problem compounds below health standards thresholds.

2.3 Noted.

We have not received up to date resource study material which defines 50 billion tons resource base. Please furnish.

The resource base at Sultani alone is adequate to support two 400 MW power projects, capacity subject water availability. The 2-million cubic metre per year water allowance for oilshale will limit development to about 600 MW.

2.4 Selection of a combustion temperature is a balance between carbon combustion efficiency and heat loss due carbonate decomposition. For purposes of the Prefeasibility Study we have opted for high combustion efficiency. At lower efficiency larger shale mine/processing plants will be needed.

2.5 Bottom ash is cooled by water exchange before discharge. Cooling water is supplied to the ash screw coolers as specified by Pyropower. See Drawing M005. 2140 gpm flow for 50 MW and 860 gpm flow for 20 MW. Heat removed by the cooling water from the ash screw coolers is dissipated to atmosphere via a wet cooling tower. Pyropower should indicate the temperature of the ash discharged to be 500°F.

Initially we had considered using a heat exchanger to cool the ash and improve the cycle efficiency. Considering low cost of fuel, the additional capital costs, and the system complexities, it was decided not to employ such heat recovery systems for this project.

2.6 The suggested alternates were looked at briefly and the potential for wind blown air pollution from the ash disposal areas are too great to warrant dry disposal unless GOJ and World Bank are willing to accept such a potential problem. Wetting the ash is the only practical solution. Hopefully some cementation will occur helping to reduce future leaching potential.

2.7 JEA requirements are noted. This is a conceptual study, not a final design. Optimal design analysis can be performed during Phase II.

2.8/2.9

JEA requirements are noted and can be incorporated into the Phase II design.

2.10 The transformer size is adequate for base load operation. A higher capacity can be considered at the final design stage if the Client prefers.

2.11 From our experience, it does not appear to be economical to provide additional dry cooling towers to take care of maximum ambient temperatures which may prevail only for a short period of time in a year. To study this, an annual dry bulb temperature duration curve is required. Also, adding additional dry cooling towers will change the plant performance. It should also be noted that the dry cooling towers are very expensive and the size should be selected carefully, considering performance and cost and not on the basis of maximum ambient temperatures. This can be studied during Phase II.

2.12 The plant gross output varies with condenser pressure:

| Condenser Pressure | Design: 5.5 in HgA | | | Annual Ave: 3.5 in HgA | | |
|---|---|---|---|---|---|---|
| Unit Size MW | 20 | 50 | 4x100 | 20 | 50 | 4x100 |
| Gross Output, MW | 23.4 | 59.3 | *496 | 24.15 | 60.7 | *TBD |
| Net Output, MW | 19.75 | 50.1 | *400 | 20.5 | 51.5 | *TBD |

*To be developed in Phase II.

Output for 4x100 MW is estimated by others.

2.13 The fan power consumption of the CFB boiler is about 30 to 35% of the total auxiliary power. The fan power consumption of the dry cooling tower is about 20 to 25% of the total auxiliary power

2.14 Table 1-1 does not include plant net output. Therefore, do not understand the comment.

2.15 Commercial operating experience with coal fueled CFBC units in USA and Europe has been uniformly good, showing high on stream availability in early years. (See Table 2-6, which reports on Pyropower experience.)

We expect operations with high ash content fuel like oilshale will have unique scale up problems such as:

- o Solid handling in and out
- o Internal solids circulation
- o Erosion/corrosion steam generator intervals
- o Heat recovery from bottom ash

Consequently we are recommending these items be worked out in a single 50 MW prototype.

2.16 Maximum dry cooling is used in this study. A small wet cooling tower is used on circulating service water system.

2.17 Horizontal condensate pump is adequate with dry cooling tower and it is cheaper. Vertical condensate pumps with cans can be considered in the final design, if required.

2.18 A concrete shell brick lined flue stack will be larger in diameter and costs more than a steel lined stack. Brick lined stack can be considered in the final design.

2.19 Demineralized water tank capacity for 50 MW is 76 cu. meters or 20,000 gallons; not 1000 cu meters. For 20 MW plant it is 38 cu. meters or 10,000 gallons.

2.20 It is U.S. practice to use an <u>average</u> continuous blowdown rate of 1% and maximum blowdown rate of 3% for this type of plants.

2.21 This can be studied during Phase II.

2.22 Same as 2.21

2.23 Same as 2.21

2.24 The recommended action plan calls for continuing support studies covering the referenced items. Additional effort is needed to further define these matters and confirm the conceptual plan.

The next step is to develop an outline for a project plan including:

- Work Scope
- Schedule
- Budget

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.

### 6.02.5 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.

Table 6-1

SUMMARY OF 400 MW PLANT OIL SHALE MINING AND PROCESSING COSTS

| | 50/50 Debt-Equity US $1000 | 80/20 Debt-Equity US $1000 |
|---|---|---|
| Capital Cost | | |
| Mine Development | 30915 | 30915 |
| Mine Equipment | 66012 | 66012 |
| Process Plant Facilities | 50889 | 50889 |
| Spare Parts | 5000 | 5000 |
| Working Capital | 10000 | 10000 |
| Capitalized Interest During Construction | 24423 | 39075 |
| TOTAL | 187239 | 201891 |
| Operating Costs and Other Costs | | |
| Annual Cost | 60386* | 53236* |
| Product Mined and Processed | | |
| Annual Tonnes x 1000 | 7783 | 7783 |
| Unit Cost | | |
| US $/Tonne (weighted average) | 7.76 | 6.84 |
| US $/$10^6$Btu (weighted average) | 1.56 | 1.38 |

*Year 12 costs taken as 25 year average.

Table 6.10
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) | $1000 | $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 | 2628 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 6.02.7) | 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 6.02.7) | 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 6.12
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 | 2,6[illegible]8 |
| SUB TOTAL PLANT COSTS (TPC) | $1000 | $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 6.02.7) | 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 6.02.7) | 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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