**Western States Enhanced Oil Shale Recovery Program
Shale Oil Production Facilities
Conceptual Design Studies Report**

Topical Report

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LIST OF NOMENCLATURE AND ABBREVIATIONS

AGR	Above Ground Retort
Bbl	Barrel
BPCD	Barrels per Calendar Day
BPSD	Barrels per Stream Day
BTU	British Thermal Unit
CD	Calendar Day
CFBC	Circulating Fluidized Bed Combustor
C-b	Cathedral Bluffs
EOR	Enhanced Oil Recovery
GPM	Gallons per Minute
GPT	Gallons per Ton
H ₂ S	Hydrogen Sulfide
HIGG	Hot Inert Gas Generator
HRS	Hot Recycled Solids
IRR	Internal Rate of Return
Kwh	Kilowatt-hour
lbs/hr	Pounds per Hour
LLNL	Lawrence Livermore National Laboratory
L.O.	Light Oil
MIS	Modified-in-Situ
MM	Million
MW	Megawatts
NO _x	Nitrous Oxides
NPV	Net Present Value
OUG	Oil Upgrading
PSA	Pressure Swing Absorption
PURPA	Public Utilities Regulatory Policy Act
S	Sulfur
SCF	Standard Cubic Feet
SCFD	Standard Cubic Feet per Day
SCOT	Shell Claus Off-gas Treating
SD	Stream Day
SFC	Synthetic Fuels Corporation
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
SPF	Surface Processing Facilities
ST	Short Ton (2000 pounds)
STPY	Short Tons per Year
TPCD	Tons per Calendar Day
TPSD	Tons per Stream Day
TPSH	Tons per Stream Hour
URS	Underground Retorting System

EXECUTIVE SUMMARY

This report analyzes the economics of producing syncrude from oil shale combining underground and surface processing using Occidental's Modified-In-Situ (MIS) technology and Lawrence Livermore National Laboratory's (LLNL) Hot Recycled Solids (HRS) retort. These retorts form the basic technology employed for oil extraction from oil shale in this study. Results are presented for both Commercial and Pre-commercial programs.

For a Commercial plant at the Cathedral Bluffs (C-b) site, with an investment of 1.2 billion dollars, in Rio Blanco County, Colorado, the economic analyses indicate that a twenty percent (20%) return on equity will require a syncrude price of \$23.35 dollars per barrel. This price assumes a 2% real growth (above inflation) in the price of oil.

Also analyzed in the report are the Pre-commercialization cost of Demonstration and Pilot programs which will confirm the HRS and MIS concepts and their mechanical designs. These programs will provide experience with the Circulating Fluidized Bed Combustor (CFBC), the MIS retort, the HRS retort and establish environmental control parameters. A Pre-commercialization study at C-b will require a total after tax expenditure of \$213.4 million dollars over a period of 10 years.

Four cases are considered to develop the Commercial and Pre-commercialization programs. This study determines budget cost estimates and schedules for each of the cases. The process flow schemes and basic heat and material balances are determined for the HRS system. The results of this study consist of summaries of major equipment sizes, capital cost estimates, operating cost estimates and economic analyses.

The four cases are:

Case 1 - Commercial Size Plant

Case 2 - Demonstration Size Plant

Case 2A- Demonstration Size Plant - minimum size CFBC

Case 3 - Pilot Size Plant

Case 2, 2A and 3 are combined for the Pre-commercialization program. This program integrates the schedules for the

Demonstration and Pilot size plants. The pro-forma cash flow for an integrated Pre-commercialization program is analyzed.

Individual cases are more fully described below:

Case 1 is the Commercial size facility which produces 24,344 BPSD of syncrude. The facility includes mining facilities, MIS processing, materials handling, HRS above ground retorting (AGR), Circulating Fluidized Bed Combustor, Oil Upgrading and a syncrude pipeline. This plant is sized with 22 simultaneously operating MIS retorts, five CFBC's and one HRS above ground retort. The HRS above ground retort facility is designed for a throughput of 12,850 tons of raw shale per day which comes from the void space produced in the retorts before rubblization. The net electric power production is 39 megawatts.

Case 2 is the Demonstration size plant which produces 1884 BPSD of shale oil. The plant includes: MIS mining, MIS processing, materials handling, HRS above ground retorting and the CFBC. Two simultaneously operating MIS retorts, one CFBC and one AGR are in operation for this plant. The CFBC is sized to be one of the five required for the Commercial plant. This CFBC is larger than required for processing the MIS off-gas and supplemental fuel (coal) will be required to operate at capacity. The supplemental fuel will require additional material handling but will also produce extra power for sale. The CFBC can later serve as one of the units needed in the Commercial size plant. The raw shale feed to the HRS above ground retort will be 1,000 tons/day. This case will produce 25 megawatts of power. The use of coal may qualify the plant for benefits under the government's Clean Coal Technology program.

Case 2A is also a Demonstration size plant. The difference between this case and Case 2 is the size of the CFBC. The CFBC is sized to optimally handle the effluents from the above and below ground retorts with a minimum of supplemental fuel. This reduced size CFBC will reduce the capital investment for the Demonstration plant. The power available for sale is 4 megawatts.

Case 3 is the Pilot size plant. The objective of this size plant is to establish the process design and operating conditions for the HRS retort. The raw shale feed is 100 tons/day of raw shale. The only facilities involved are the materials handling and the Above Ground Retorting system. There will not be any mining involved as the shale is already stockpiled ready for crushing and feeding into the retort. The pilot plant produces 62 BPSD of shale oil.

In addition to the above descriptions, other equipment requirements include storage and truck loading facilities for product oil from the Pilot and Demonstration size plants. Hauling of spent shale from the CFBC is provided, as is a flare system in the pilot facility for the incineration of process off-gas.

The shale oil products produced in each of the cases are summarized in Table 1-1.

Federal lease C-b comprises a 5,094 acre tract of land in Rio Blanco County in Colorado. This tract is leased from the U. S. Department of Interior by Occidental Oil Shale, Inc. The current mine shafts give access to recoverable reserves of 1.8 billion barrels of shale oil.

The design basis was derived from engineering studies and process designs carried out by Bechtel and other contractors. The mining cost estimates, provided by Agapito and Associates, are located in the appendix.

DESIGN BASIS

The design bases for all cases are summarized in Table 1-2.

Case 1 is the Commercial size plant with 22 MIS retorts burning simultaneously, one AGR and five CFBC's. The overall oil production from MIS and HRS retorts amounts to 24,344 BPSD, after upgrading. The Above Ground Retort throughput is 12,850 tons/day of mined raw shale.

Case 2 and 2A, the Demonstration size plant, will consists of two MIS retorts with a HRS retort to give a total raw shaleoil production rate of 1884 BPSD. Mined raw shale processing in the Above Ground Retort is 1,000 tons/day.

Case 3, the Pilot size plant will produce 62 BPSD of raw shale oil. No MIS retorts are used in this case. This plant will process 100 tons/day of stockpiled raw shale.

COST

The capital and operating cost for the four cases are summarized in Tables 1-3 and 1-4, respectively. The total capital cost and operating cost for these cases are as follows:

	Capital Costs (\$ millions)	Operating Costs (\$ million/year)
Case 1	1,162.9	178.0
Case 2	243.5	34.6
Case 2A	230.8	30.3
Case 3	19.5	5.0*

* Based on one year of operation

The following items are not included in these capital costs:

- Sunk cost already expended in the development at the C-b site
- Costs associated with working capital and financing
- Income taxes

SCHEDULE

The overall schedules for Cases 1, 2/2A, and 3 are shown in Figures 1-1 through 1-3. The time required from kickoff until the completion of Commissioning and Start-up is summarized below.

Case 1	Commercial Plant	6 years
Case 2, 2A	Demonstration Plant	4 years
Case 3	Pilot Plant	3 years

If process development on the three cases is done sequentially, the overall schedule would be approximately 15 years. This allows for the Pilot and Demonstration plants to be in operation one year each before design of the next size facility.

The Pre-commercialization plan, which integrates the schedules of the Pilot and Demonstration Plant, and takes into account the advanced readiness of the MIS retort, will take a total of 10 years. The project schedule for this pre-commercialization plan is shown

in Figure 1-4. This integrated schedule would allow for a faster start-up of the MIS Commercial size plant and accomodate the longer development schedule for the HRS process.

ECONOMIC ANALYSIS

An economic analysis is presented which determines the oil price required to generate return on equity for Case 1, the Commercial size plant. Cases 2 and 3 are combined into the integrated Pre-commercialization plan and 10 year cash expenditures are computed.

The results of the economic analysis for the commercial case are summarized in Figure 1-5. The curves show the oil prices required to obtain returns on equity varying from 5 to 25 percent. The curves assume a financing structure of 75% debt and 25% equity with a ten percent (10%) interest on debt. The income tax rate was calculated at 37.3 percent. The curves are developed based on oil prices keeping pace with inflation and inflation plus 2% per year real growth. The inflation rate used in these calculations is 5 percent per year. The required shale oil prices for the Commercial size plant are shown below.

Required Shale Oil Price vs Return On Equity, (\$/BBl)

Return on Equity	0% growth	2% growth
5	25.58	17.80
10	26.70	19.57
15	27.90	21.40
20	29.35	23.35
25	31.05	25.40

(adjusted for an inflation rate of 5%/year)

The detailed cash flow analyses are shown on Tables 1-5 and 1-6.

For the demonstration, pilot, and integrated Pre-commercialization facilities, the cumulative after tax cash flows are as follows:

Cumulative After Tax Cash Flows, \$MM

Case 2	-	206.6
Case 2A	-	227.7
Case 3	-	18.0

Pre-commercialization Plan

The integrated Pre-commercialization plan can be built and operated for \$213.4 MM depending on future financial conditions and assumptions for revenues generated from oil and power sales. The program will perfect MIS mining and oil shale processing technologies and provide experience needed for scale up and process integration.

The cash requirements for the Pre-commercialization plan can be reduced by allowing outside participation in certain sections of the facility. For example, an electric utility may be interested in owning the CFBC and power generation sections. By allowing outside participation, the annual cash flow requirements and long term benefits can be spread among project participants.

PROJECT DESCRIPTION

The processing facilities for Case 1 are shown in Figure 1-6, with the material balance shown in Table 1-7. The Demonstration facilities for Cases 2 and 2A are shown in Figure 1-7, with the material balance shown in Table 1-8.

The Pilot plant consists only of the HRS above ground retort and associated equipment. It does not incorporate the MIS retort or off-gas processing units. It will be used to test the spent shale cooling and moisturizing process. A block flow diagram for this case appears as Figure 1-8.

The processing facilities are shown in Figures 1-9, 1-10 and 1-11.

Modified-In-Situ Development Mining

MIS Mining. Mining for retort development will occur on three mining levels: upper void, intermediate void and lower void levels. Clusters of retorts will be accessed through a double entry drift system on each level using an advance mining system. system of ore passes and ventilation raises will provide ventilation and provide for transfer of mined shale to the loadout bins. Warehouses and shops are located on the mining levels. An isometric sketch of the mine retorts is shown in Figure 1-12.

The underground retort is a rectangular column of shale which is prepared by mining out a total of 23% of the retort volume from the appropriate levels.

MIS Rubblization and Construction. After the retort is mined, the retort must be fragmented to a uniform particle size. Vertical blastholes are drilled into the retort block from the upper and intermediate levels. Horizontal blastholes are drilled into the support pillars on each level.

The blastholes are loaded with explosives and rubblized with one sequential blast. After rubblization, retort bulkheads are constructed in the retort access drifts. All process piping and instrumentation for retort operations are connected to and through the bulkheads.

For the commercial mine, 28 retorts per year will be mined out and developed. This requires completion of the existing loadout bins at the bottom of the mine shaft and the construction of a large live storage bin underground, connecting shafts and a materials handling conveyor system.

For the development mine, 17 retorts will be developed during a 5 to 6 year mining program. The shale handling facilities which presently exist with some modifications and completion will be able to handle the mined shale.

Modified-In-Situ Processing Facilities

MIS processing facilities consist of two subsets: Underground Retorting system and Surface Processing Facilities system. The Underground Retorting system consists of MIS retorts, off-gas drifts (or piping in the Demonstration case), raises common to all retorts, and piping and control units which connect individual retorts to the common off-gas drifts. Low BTU gas is transported to the surface through common off-gas drifts and raises. Off-gas collected from the In-situ operation is combined with off-gas from the active AGR retort and then fed to the CFBC.

Surface processing facilities consist of off-gas processing, off-gas compression and foul water stripping. The off-gas is a low-BTU fuel gas saturated with water and contains condensable hydrocarbons, ammonia and sulfur bearing constituents. Condensable hydrocarbons are recovered by processing the off-gas through water contact condensers and sponge oil scrubbers. Cooling also condenses water which is stripped of ammonia and sulfur bearing constituents. The water is then used in the deashing process. The ammonia and sulfur bearing constituents are incinerated in the CFBC.

Material Handling Facilities

The materials handling facilities contain equipment for receiving and stockpiling crushed shale from the mine and for providing surge storage between the mine and surface facilities. The shale is crushed and screened to 1/4 inch. The shale feed to the above ground HRS Pilot plant retort will be taken from a stockpile, crushed and screened.

Above Ground Retorting Facilities

The Above Ground Retort employs an innovative concept developed by Lawrence Livermore National Laboratory (LLNL) which uses a recirculating hot-solid heat carrier to accomplish pyrolysis.

This hot-recycled-solids (HRS) retort consists of a Pyrolyzer (retort) through which raw shale and hot-recycled-solids pass in plug flow by gravity. Oil vapor and gas derived in the pyrolyzer pass radially across the pyrolyzer and are collected and removed at several points. The retorted shale is conveyed pneumatically through an Air Lift combustor to a Classifier where the hot solids disengage from the flue gas. The hot solids fall from the Classifier through a Delayed Fall Combustor followed by a Fluidized Bed Combustor (FBC) where essentially all combustibles remaining on the recycled solids are burned. Removal of retorted shale from the FBC is regulated to maintain a level in the FBC. The hot recycled solids are combined with raw shale in a Fluid Bed Mixer before entering the Pyrolyzer.

The hot-recycled-solids retort concept has several advantages over gas heated retort concepts.

- Gas compression costs are significantly lower.
- Rapid shale throughput is possible (reducing product degradation due to cracking and less shale residence time).
- Fine shale particles can be processed and need not be discarded or combusted.
- Minimal gas cleanup is required over processes which use air. (hot gas is not diluted with nitrogen).

Major pieces of equipment are shown in Figure 1-9.

The oil vapor quench system consists of two (2) quench towers and associated equipment as shown in Figure 1-10. The deashing system consists of mixing the oil with hot water and electrostatically separating the oil and water phases. (The latter containing the ash.)

Oil Upgrading Facilities

The oil upgrading facilities provided in the commercial plant, consist of five major units: fractionation, hydrotreating, hydrogen production, sour water treating, and sulfur recovery. The hydrotreating unit treats the raw shale oil with hydrogen over a proprietary catalyst to remove the nitrogen, oxygen and sulfur. This process produces a high quality syncrude which will exceed specifications for pipelining and conventional refinery feed. The hydrotreating and hydrogen units are sized to accommodate oil production from both the MIS and AGR retorts.

The hydrogen unit is a conventional reformer which utilizes natural gas for feed and a Pressure Swing Absorption (PSA) section to maintain high hydrogen purity. Wash water used for control of salt formation in the hydrotreating unit exchangers is stripped of H₂S and ammonia before recirculation to the hydrotreating unit.

Hydrogen sulfide produced by hydrogenation is converted to elemental sulfur in a conventional Claus unit with a SCOT tail gas unit provided to reduce the sulfur emissions to prescribed limits.

Ammonia is recovered by means of a proprietary process, Phosam-W.

Circulating Fluidized Bed Combustor Power Generation

Low-BTU off-gas from MIS and off-gas streams from other units are fed to the CFBC along with spent shale from the HRS retort. Superheated steam at 1,325 psia and 955°F is generated in the CFBC for the Commercial size plant. Steam at the same conditions is generated in the Demonstration size plant. The superheated steam is fed to a steam turbine generator to produce power and to extract steam at various pressures required within the facilities. Virgin oil shale and/or retorted shale, which contains considerable calcium and alkali minerals, capture SO₂ from the feed materials. Coal is provided as a supplemental fuel for CFBC flame stability.

Product Oil Transport Facilities

Syncrude produced in the Commercial size plant (Case 1) is shipped to an existing crude oil pipeline at Rangely, Colorado by means of a syncrude pipeline. For the Pre-commercialization facilities, the product shale oil will be transported by truck.

TECHNICAL FEASIBILITY

Technical feasibility assessments have been carried out on the following major process units:

- MIS Technology
- Above Ground Retorts (AGR) facilities
- Oil Upgrading facilities (OUG)
- Circulating Fluidized Bed Combustor (CFBC)

MIS Technology

MIS retorts have been demonstrated since 1972. Commercial size retorts number 7 and 8 located at Logan Wash produced extensive data for the design basis.

Processing the MIS off-gas utilizes conventional refinery type hydrocarbon processing technologies. These technologies have been used extensively in petroleum refining throughout the world.

Above Ground Retort (AGR) Facility

The HRS retort has been demonstrated on a laboratory scale by LLNL since 1984. Case 3, the Pilot plant, will be used to demonstrate the workability of the design and scale up from laboratory size. Research on a pre-pilot plant scale is also anticipated prior to completion of the design for the pilot plant.

Oil Upgrading Facility (OUG)

Upgrading of the shale oil from both the MIS and HRS retorts utilizes conventional technology. The processes employed have

been demonstrated at commercial scale at the Unocal Parachute, Colorado plant. It has processed over one million Barrels of shale oil through the oil upgrading facility.

Sour water produced will be used in the deashing process and for moisturizing shale ash from the CFBC.

The deashing process is an electrostatic demineralization process used extensively in petroleum refining throughout the world.

Circulating Fluidized Bed Combustor (CFBC) _____

The CFBC has been used at a commercial size for coal processing with limestone as the SO_x adsorbent. The licensor of the technology believes that after testing at pilot scale, the technology is ready for demonstration scale testing utilizing MIS gas and coal, with shale as an adsorbent.

Table 1-1

SHALE OIL PRODUCTION

(BPSD)

	CASE			
	1	2	2A	3
MIS OIL	13,964	1,269	1,269	---
AGR OIL	7,930	615	615	62
TOTAL MIS PLUS AGR OIL	21,894	1,884	1,884	62
TOTAL OIL AFTER UPGRADING	24,344	---	---	---

NOTE: Case 1 is the Commercial Plant
Case 2 is the Demonstration Plant
Case 2A is the Demonstration Plant
with minimum size CFBC
Case 3 is the Pilot Plant

Table 1-2
Design Criteria

Basis	Case 1	Case 2/2A	Case 3
<u>Site</u>			
Location	Commercial C-b tract Rio Blanco County	Demonstration C-b tract Rio Blanco County	Pilot C-b Tract Rio Blanco County
<u>Mining Facilities</u>			
Mine type	Shaft Mine	Shaft Mine	
Classification	Gassy-Nonmetal	Gassy-Nonmetal	
Mining Method	-	-	N/A
Oil shale Grade	-	-	
Productions Days	-	-	
Annual Production	0	0	
<u>MIS Retort Development Mining Facilities</u>			
Mining Method	Rm. & Pillar (ea. void level)	Rm. & Pillar (ea. void level)	
Oil Shale Grade			N/A
- mined to AGR/CFBC	27 GPT Average	27 GPT Average	
- rubblized-in-place	27 GPT Average	27 GPT Average	
Production Days	357 Days per Year	357 Days per Year	
Annual Production	4,700,000 Tons	420,000 Tons	
<u>Material Handling Facilities</u>			
Local Coarse Shale Stockpile	37,000 T Live, 13,500 T Dead	4500 T Live, 13,500 T Dead	Coarse shale stockpile from mine
Remote Coarse Shale Stockpile	3.6 Million Tons	-	development
Retort Feed Storage	7,000 Tons (13 hours)		
<u>Aboveground Retort Facilities (AGR)</u>			
Retort Technology	LLNL HRS	LLNL HRS	LLNL HRS
Retort Feed	12,800 TPSD	1000 TPSD	100 TPSD
Feed Shale Grade	27 Gallons per Ton	27 Gallons per Ton	27 Gallons per Ton
Steady State Stream Factor	95%	95%	95%
No. of Retorts	1	1	1

Table 1-2
Design Criteria (Continued)

Basis	Case 1	Case 2/2A	Case 3
<u>Modified in Situ Processing Facilities</u>			
Underground Retorting System			
Retort Technology	Occidental MIS Technology	Occidental MIS Technology	
Retort Processing Rate	22 Retorts Burning Simultaneously 1 Retort Ignited Every 14 Days 27.5 Retorts Processed per Year	2 Retorts Burning Simultaneously 1 Retort Ignited Every 146 Days 2.5 Retorts Processed per Year	N/A
<u>Oil Upgrading Facilities</u>			
Hydrotreating Technology	Union Oil		
Normal Feed Rate	21,894 BPSD (20,799 BPCD)	N/A	N/A
Sulfur Removal Technology	Claus Unit		
Syncrude Production	8.4 Million Barrels per Year		
<u>Syncrude Pipeline Facilities</u>			
Capacity	23,000 BPCD	N/A	N/A
Destination	Chevron Rangely Terminal		
<u>Utilities and Offsite Facilities</u>			
Intermediate and Syncrude Tankage	7 days	15 days storage for light and bulkhead	Drums
Water Source	Mine Inflow supplemented with wells	Mine Inflow supplemented with wells	Mine in flow supplemented with wells
Overcapacity	Minimal	Minimal	Minimal
Power Source	Power generated at site	Power generated at site	Purchased
<u>Coal</u>			
Feed to CFBC, TPD	1044	504/95	
Coal Stockpile, Tons	7000	3400/650	N/A
Feed Storage, Tons	250	50/25	
<u>Capacity of Product/By-Products</u>			
Light Oil, BPCD	-	366	-
Bulkhead Oil, BPCD	-	840	-
Power to Grid, MW	39	25/4	-
Treated Oil, BPCD	23,126	1790*	58*

* Raw untreated shale oil.

Table 1-3

CAPITAL COST SUMMARY
(\$ Millions)

AREA/UNIT NUMBER	DESCRIPTION	CASE 1	CASE 2	CASE 2A	CASE 3
--	MINE	148.3	27.0	27.0	0.0
--	MIS RETORT RUBBLIZATION & CONSTRUCTION	34.6	4.2	4.2	0.0
3700	UTILITIES	16.8	5.2	5.2	0.0
4000	POWER DISTRIBUTION	15.7	4.9	4.9	0.0
4100	INTERCONNECTING PIPEWAYS	16.8	4.3	4.3	0.0
4200	BUILDINGS	21.3	13.8	13.8	0.5
4300	SITE PREPARATION & DEVELOPMENT	16.8	5.8	5.8	0.2
4400	MOBILE EQUIPMENT	6.7	2.9	2.9	0.1
4500	TANK FARM, YARD & FLARE	7.8	1.2	1.2	0.0
4560	SYNCRUDE PIPELINE	11.2	0.0	0.0	0.0
4611-14	HRS RETORT, QUENCH, DEASHING & RECYCLE GAS	31.5	11.6	11.6	9.2
4615	FRACTIONATION	9.5	0.0	0.0	0.0
4700	SHALE PREPARATION & HANDLING	6.6	4.0	4.0	0.7
4900	CONTROL SYSTEMS	4.4	1.1	1.1	0.0
5000	OIL UPGRADING FACILITIES	121.0	0.0	0.0	0.0
6000	MIS PROCESS FACILITIES	134.7	23.4	23.4	0.0
7000	CFBC/POWER GENERATION	162.5	52.3	43.6	0.0
TOTAL DIRECT FIELD COST		766.2	161.7	153.0	10.7
INDIRECT FIELD COST		188.7	39.8	37.7	2.6
TOTAL FIELD COST		954.9	201.5	190.7	13.3
HOME OFFICE COST		106.6	22.5	21.3	1.5
TOTAL FIELD AND HOME OFFICE COST		1061.5	224.0	212.0	14.8
SPARE PARTS		7.1	1.5	1.4	0.1
STATE & LOCAL TAXES		25.4	5.4	5.1	0.3
UNALLOCATED COST AND ROYALTIES		68.8	12.6	12.4	4.3
TOTAL PROJECT COST		1162.8	243.5	230.9	19.5

The sunk capital costs expended to-date are not included in the capital costs listed above.

△ 2-5-90

Table 1-4

ANNUAL OPERATING COSTS
(\$ thousands/year)

		Case 1		Case 2		Case 2A		Case 3	
		Usage	Cost	Usage	Cost	Usage	Cost	Usage	Cost
Natural Gas	\$2.00 /MMBTU	702	12,299	11	193	11	193	1	18
Coal	\$1.25 /MMBTU	896	9,811	433	4,741	82	892	0	9 (3)
Electricity	\$0.05 /kwh	0	0	0	0		0	171	75
Diesel Fuel	\$1.25 /gallon		1,115		85		85		5
Raw Water	\$250 /ac-ft	3055	361	145	0	145	0	61	30 (4)
Catalysts and Chemicals			7,600		29		29		0
Operating Labor		343	13,720	150	6,000	150	6,000	92	2,208 (5)
Maintenance Material & Labor			20,515		4,330		4,097		286
Spent Shale Disposal			300		27		27		24
Retort Rubblization & Construction			44,324		4,708 (2)		4,708 (2)		0
Mining			42,942		5,920 (2)		5,920 (2)		0
Unallocated Support			25,051		8,541		8,314		2,305
			178,039		34,574		30,265		4,960

Notes:

1. Does not include income taxes or Federal lease royalties.
2. First year of operation costs. Retort rubblization complete in two years of operation and retort construction in four years. Mining costs decrease for next two years as mining of retorts is completed.
3. Cost to dig and crush shale for feedstock.
4. Costs for raw water and for a steam boiler and water treating.
5. Cost for contract operators and maintenance for 1/2 year.

CASH FLOW PROJECTIONS - 0% REAL GROWTH
(\$ millions as spent)

[illegible]

CASH FLOW PROJECTIONS - 0% REAL GROWTH
(\$ millions as spent)

[illegible]

Commercial Plant - Case 1

[illegible]

Table 1-6

CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ millions as spent)

Commercial Plant - Case 1

YEAR	0	1	2	3	4	5	6	7	8	9	10
PRODUCTION AND PRICES:											
OIL PRODUCTION,MMBBL/YR	0	0	0	0.422049	4.220495	7.174841	8.44099	8.44099	8.44099	8.44099	8.44099
ANNUAL OIL PRICE	23.35	25.01	26.78	28.69	30.72	32.90	35.24	37.74	40.42	43.29	46.36
CASH FLOW;											
OIL REVENUES	0.0	0.0	0.0	12.1	129.7	236.1	297.5	318.6	341.2	365.4	391.4
BY-PRODUCT CREDITS	0.0	0.0	0.0	0.0	10.5	20.7	29.0	30.4	31.9	33.5	35.2
REVENUES	0.0	0.0	0.0	12.1	140.2	256.8	326.4	349.0	373.1	398.9	426.5
O AND M COSTS	0.0	0.0	0.0	4.0	50.1	221.3	248.3	262.4	346.4	289.4	304.0
INTEREST EXPENSE						7.0	128.1	128.1	128.1	128.1	128.1
NET OPERATING INCOME	0.0	0.0	0.0	8.1	90.1	28.5	-50.0	-41.5	-101.4	-18.6	-5.6
TAX DEPRECIATION	0.0	10.9	47.4	127.6	228.6	279.1	256.0	205.0	162.6	135.4	102.8
DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EARNINGS BEFORE TAX	0.0	-10.9	-47.4	-119.5	-138.5	-250.6	-306.1	-246.5	-263.9	-154.0	-108.3
INCOME TAXES	0.0	-4.1	-17.7	-44.6	-51.7	-93.5	-114.2	-91.9	-98.4	-57.4	-40.4
EARNINGS AFTER TAX	0.0	-6.8	-29.7	-74.9	-86.8	-157.1	-191.9	-154.5	-165.5	-96.6	-67.9
+ TAX DEPRECIATION	0.0	10.9	47.4	127.6	228.6	279.1	256.0	205.0	162.6	135.4	102.8
+ DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- EQUITY COSTS	0.0	38.0	63.5	176.6	99.6	49.3	0.0	0.0	0.0	0.0	0.0
- REPLACEMENT COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- INCREASE WORKING CAP	0.0	0.0	0.0	7.4	22.3	10.8	5.4	2.7	-2.9	9.1	3.4
NET CASH FLOW	0.0	-33.9	-45.8	-131.3	19.9	61.9	58.7	47.7	0.0	29.8	31.5
CUM. NET CASH FLOW	0.0	-33.9	-79.7	-211.0	-191.2	-129.3	-70.6	-22.8	-22.8	6.9	38.4

Table 1-6 (continued)

CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ millions as spent)

Commercial Plant - Case

[illegible]

**CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ MILLIONS AS SPENT)**

[illegible]

COMMERCIAL PLANT

[illegible]

COMMERCIAL PLANT

[illegible]

Table 1-8
OVERALL MATERIAL BALANCE - CASE 2
DEMONSTRATION PLANT

[illegible]

Table 1-8 (Continued)

OVERALL MATERIAL BALANCE - CASE 2

DEMONSTRATION PLANT

[illegible]

Figure 1-1
PROJECT SCHEDULE
CASE 1 - COMMERCIAL

Figure 1-2
PROJECT SCHEDULE
CASE 2 AND 2A - DEMONSTRATION

Figure 1-3
PROJECT SCHEDULE
CASE 3 - PILOT PLANT

Figure 1-4

PRE-COMMERCIALIZATION SCHEDULE

Figure 1-5

COMMERCIAL SHALE OIL ECONOMICS

IRR vs OIL PRICE - Case 1

Figure 1-7
BLOCK FLOW DIAGRAM
DEMONSTRATION SIZE PLANT
CASES 2, 2A

Figure 1-8

**BLOCK FLOW DIAGRAM
PILOT SCALE PLANT
CASE 3**

UTILITIES AND OFFSITE FACILITIES

UTILITIES

3710	Mine Water System
3740	Cooling Water System
3750	Inert Gas Generation System
3760	Instrument & Plant Air System
3770	Fuel Gas System
3780	Potable Water System
3781	Fire Water System
3782	Service Water System
3783	Oily/Storm Water System
3784	Sanitary Sewer System

OFFSITE FACILITIES

4000	Power Distribution
4100	Interconnecting Pipeways
4200	Buildings
4300	Site Preparation & Development
4400	Mobile Equipment
4530	Tank Farm
4540	Rifle Marshalling Yard
4550	Emergency Flare System
4900	Control System

Figure 1-9

HRS RETORT ASSEMBLY

Figure 1-10
HRS RETORT GAS PROCESSING
FLOW DIAGRAM

Figure 1-11

**MRS SPENT SHALE
PNEUMATIC TRANSPORT AND COOLING SYSTEM - CASE 3**

Figure 1-12
MIS MINE ISOMETRIC

INTRODUCTION

This conceptual design study report presents technical data, costs and economic analyses of plants producing shale oil using Occidental Oil Shale, Inc.'s Modified-In-Situ (MIS) retorting technology, and a Hot-Recycled-Solids (HRS) retort developed by Lawrence Livermore National Laboratory (LLNL). A Circulating Fluidized Bed Combustor (CFBC) is used for the clean-up of effluent gas streams as well as for power generation.

Four cases have been examined in this study based on a site located on federal lease C-b, comprising a 5,094 acre tract of land in Rio Blanco County, Colorado.

The cases are as follows:

Case 1 is the Commercial size facility which involves mining facilities, MIS processing, materials handling, HRS above ground retorting, CFBC, oil upgrading and a syncrude pipeline. This process is sized with 22 simultaneously operating MIS retorts and four CFBC's. The Above Ground retort processing facility is designed for a throughput of 12,850 tons of raw shale per day which is the production of shale from the 22 simultaneously burning retorts. The total oil production from the HRS and MIS processes is 24,344 BPSD and net power production is 39 megawatts.

Case 2 is the Demonstration size plant. The areas involved are MIS mining, MIS retorts, above ground retorting and the CFBC. Two MIS simultaneous retorts and one CFBC are in operation for this plant. The CFBC used is sized to be one of the four required for the Commercial case. This combustor is larger than will be required for the Demonstration plant, and supplemental fuel (coal) will be required to maintain the flame stability. The increased fuel consumption will require additional handling and transportation costs, but will also reduce the capital cost required in the Commercial size facility. The CFBC can serve as one of the four combustors needed in the Commercial size plant. The raw shale throughput to the Above Ground Retort will be 1,000 tons/day. This case will produce 25 megawatts of power. The use of coal may qualify the plant for benefits under the government's Clean Coal Technology program.

Case 2A is also a Demonstration size plant. The difference between this case and Case 2 is the size of the CFBC. The combustor is sized to optimally handle the effluents from the above and below ground retorts with a minimum of supplemental fuel. This reduced size CFBC will reduce the capital investment for the

Demonstration plant, but it is smaller than desired for the Commercial size facility. Case 2A will produce 4 megawatts of power.

Case 3 is the Pilot size plant. The objective of this size plant is to optimize the process design and operating conditions for the HRS retort. The throughput is 100 tons/day of raw shale. The only facilities involved are the materials handling and the above ground retorting system. There will not be any mining involved as the shale is mined and stockpiled, ready for crushing and loading into the retort.

This study report consists of the following sections in addition to the Executive Summary.

The DESIGN BASIS section summarizes the bases used in the design of the various plant units. In addition, the key characteristics and capacities of the various units are described.

The COSTS section presents capital and operating costs for all four cases. It describes the basis and methodology used to estimate capital costs, and the costs associated with operation and maintenance of the facilities.

The SCHEDULE section contains project schedules for Cases 1, 2/2A and 3. There is also a schedule for a Pre-commercialization plan, which combines the Pilot and Demonstration plants into an integrated schedule.

The ECONOMIC ANALYSIS section summarizes the economics of producing shale oil and power for these cases. The shale oil prices to produce a range of internal rates of return (IRR) on equity were calculated for Case 1.

The PROJECT DESCRIPTION section describes the sequence and operation of the various processing units within the plant. Included in this section are block flow diagrams, material/energy balances, utility balances, and catalyst/chemical consumptions.

The TECHNICAL FEASIBILITY section discusses the design reliability of the various process units.

The APPENDICES include backup information referred to under Costs and Project Description.

DESIGN BASIS

The key design parameters for the four cases included in this report are summarized in Table 3-1.

The following major processing units are included in the various production facilities.

Area Unit	Major Plants	Case No.
--	MIS Retort Development and Mining	1, 2, & 2A
6000	MIS Retorts and Processing Facilities	1, 2, & 2A
4700	Mined Shale Handling/Processing	All
7000	CFBC/Power Generation	1, 2, & 2A
4600	Above Ground Retort Facilities (AGR)	All
5000	Oil Upgrading Facilities (OUG)	1
4560	Syncrude Pipeline	1
3700	Utilities/Offsites	All

The design basis used for the major process units are detailed on the following pages.

CASE 1 - COMMERCIAL PLANT

As noted above, Case 1 incorporates all the processing units listed. A block flow diagram of the commercial size plant is presented in Figure 3-1.

MIS Retort Development and Mining

While the MIS section envisions 22 retorts burning at any given time, the following description gives details on the development and mining of a single retort.

Mined cross section (sq ft)	165X165
Mined height (ft)	270

Mined void (%)	23.0
Rubblized cross section (sq ft)	160.1X160.1
Rubblized height (ft)	260
Rubblized plenum height (ft)	10.0
Rubblized void (%)	18.5
Retort volume (cu ft)	7,242,544
Plenum volume (cu ft)	272,250
Rubblized void volume (cu ft)	1,391,500
Rubble rock volume (cu ft)	5,579,860
Average shale rock density (lbs/cu ft)	137.5
Rubblized rock (tons)	384,700
Rubblized Fischer Assay (GPT)	27.0
Oil in place rubblized (Bbl)	247,307
MIS tons mined, with development, per retort (tons)	168,000
MIS tons mined, void only, per retort (tons)	111,500
Mined grade (GPT)	27.0

Production Parameters

Length of work shift (collar to collar)	10 hours
Mine operating shifts	2 shifts per day, 12 shifts per week (1 shift per day on weekends), 3 crews in rotation working 4 shifts per week each
Mine production days	357 days per year (607 shifts per year)
Time between retort ignitions	14 days
MIS tons required to be mined	4,620,000 per year (168,000 per each of 27.5 retorts, including development)
MIS tons per mine shift	7,650 tons per shift
Total available operating hours	8 hours per shift (after deducting travel, lunch and other interruptions)
Productive operating hours	7.6 per shift (efficiency adjusted for 2 shifts per day)

MIS Retorts and Processing Facilities

MIS Retort

Retort Technology Steady State Stream Factor	Occidental Oil Shale, Inc. 95%	
	<u>Annual Average</u>	<u>Design</u>
Number of burning retorts	22	22
Burning time/Retort-days	292	292
Ignition Cycle days	13.3	13.3
Number of retorts burned/year	27.5	27.5
Total Retort-Oil yield	77%	77%
Air Feed Rate/Retort		
SCFM (CD)	126,324	
SCFM (SD)	132,968	
Water Infiltration rate		
per active retort - GPM	25	25
per quench retort - GPM	25	25
Product Streams		
Total MIS Retort Off-gas MMSCFD, wet	900	948
Total Bulkhead Oil BPD	9,586	10,090
Bulkhead Oil Used as Fuel BPD	55	58
Bulkhead Oil in Water (lost) BPD	286	301
Net Bulkhead Oil Recovered BPD	9,245	9,731
Aerosol Oil (with Off-gas) BPD	1,930	2,040
Light oil in Off-gas BPD	2,790	2,940

	<u>Annual Average</u>	<u>Design</u>
Retort Water		
Total produced in active retort		
GPM	400	440
Quench Water		
Total consumed in spent retort		
GPM	400	440
Product Conditions		
Total MIS Retort Off-gas (at surface inlet to Off-gas processing)		
Press., psia	8.5	8.5
Temp., °F	156	156
Bulkhead Oil (at surface)		
Temp., °F	140	140
Retort Water (at surface)		
Temp., °F	140	140
MIS Retort Off-gas		
Total Off-gas Composition (vol % dry)		
H ₂	8.17	8.58
N ₂ + Ar	55.35	54.46
O ₂ +	0.14	0.10
CO	2.87	2.96
CO ₂	29.73	30.06
CH ₄	1.20	1.28
C ₂ H ₄	0.09	0.08
C ₂ H ₆	0.28	0.29
C ₃ H ₆	0.09	0.09
C ₃ H ₈	0.11	0.11
C ₄ 's	0.09	0.09
C ₅ 's	0.04	0.04
C ₆ +	0.40	0.45
NH ₃	0.58	0.62
H ₂ S	0.77	0.77
COS	20 ppm	20 ppm
CS ₂	36 ppm	36 ppm
CH ₃ SH	71 ppm	71 ppm
C ₂ H ₅ SH	71 ppm	71 ppm
Water content, vol %	37.8	39.3
Aerosol Oil API Gravity	39.7	39.7

Off-gas Processing

Off-gas Processing Technology	General Refinery Type Hydrocarbon Processing Technology	

Steady State Stream Factor	95%	

<u>Annual Average</u>	<u>Design</u>

Feed Streams

MIS Retort Off-gas MMSCFD, wet	540.3	568.7

Aerosol Oil BPD	1,930	2,040

Stripped Water, GPM		2,750

Feed Condition

MIS Retort Off-gas, Press., psia	8.5
MIS Retort Off-gas, Temp., °F	156
Stripped Water, Temp., °F	82

Feed Properties	Same as MIS Retort Off-gas	

Product Streams

Low-Btu Off-gas MMSCFD	540	569

Foul Water, GPM	3,828	4,400

Aerosol Oil (in foul water) BPD	1,930	2,040

Recovered Light Oil BPD	2,091	2,200

Total Light Oil Product BPD	4,021	4,240

Light Oil Recovery, %	75	75

Product Conditions

	<u>Annual Average</u>	<u>Design</u>
Low-Btu Off-gas, Press., psia		6.95
Low-Btu Off-gas, Temp., °F		50
Foul Water, Temp., °F		120
Recovered Light Oil, Temp., °F		110

Product Properties Low-Btu Off-gas Composition
(Vol % dry)

H ₂	8.71	8.71
N ₂ + Ar	55.31	55.31
O ₂	0.10	0.10
CO	3.01	3.01
CO ₂	29.93	29.93
CH ₄	1.30	1.30
C ₂ H ₄	0.08	0.08
C ₂ H ₆	0.29	0.29
C ₃ H ₆	0.09	0.09
C ₃ H ₈	0.11	0.11
C ₄	0.09	0.09
C ₅	0.06	0.06
C ₆ +	0.09	0.09
NH ₃	0.03	0.03
H ₂ S	0.77	0.77
COS	20 ppm	20 ppm
CS ₂	32 ppm	32 ppm
CH ₃ SH	70 ppm	70 ppm
C ₂ H ₅ SH	<u>66 ppm</u>	<u>66 ppm</u>
	100.00	100.00
LHV, BTU/SCF	69	69
H ₂ O Content, vol % of total	2.5	2.5
Aerosol Oil, API Gravity	39.7	39.7
Recovered Light Oil, API Gravity	51.8	51.8

Off-gas Compression

Feed Stream

	<u>Annual Average</u>	<u>Design</u>
Flow MMSCFD	540	569
Pressure - PSIA	7.1	6.95
Temp. - °F	50	50

Product Requirement

Pressure - PSIA	27	27
Temp. - °F	(isentropic Temperature)	

Foul Water Stripping

Feed Stream

Foul water, GPM	3,828	4,400
Composition and Conditions, ppmw		
CO ₂	7,481	7,481
NH ₃	3,018	3,018
H ₂ S	136	136
Temperature, °F	145	120
Aerosol Oil, (in foul water) BPD	1,930	2,040

Products

Stripped water, GPM	3,795	4,360
Composition, ppmw		
NH ₃	50	50
H ₂ S	8	8
CO ₂	TR	TR
Sour Gas MMSCFD	132.1	139.0
Composition, vol %		
CO ₂	5.41	5.41
NH ₃	5.72	5.72
H ₂ S	0.13	0.13
H ₂ O	<u>88.74</u>	<u>88.74</u>
Total	100.00	100.00

	<u>Annual Average</u>	<u>Design</u>
Aerosol Oil		
BPD	1,930	2,040
API Gravity	39.7	39.7
Stripping Efficiencies %		
CO ₂	100.0	100.0
NH ₃	98.6	98.6
H ₂ S	95.4	95.4

Mined Shale Handling and Processing

Mining

Underground Primary Crusher Material	-8" nominal, 20" x 12" x 8" max. lump size
Hoist Schedule	18.5 hrs/stream day
Tons Hoisted per hour (Normal Operating)	850 TPSH
Tons Hoisted per hour (Design)	2000 TPSH
Mine Production (days/year)	357 days
Bulk Density of Hoisted Rock	80 lb/cu ft
Fines Present in Hoisted Rock	5%
Rock Surface Moisture	2%

Local Coarse Shale Stockpile

Normal Feed Rate	850 TPSH
Design Feed Rate	2000 TPSH
Normal Reclaim Rate	540 TPSH
Design Reclaim Rate	650 TPSH
Live Capacity	37,000 tons (3 days)

Dead Capacity	117,700 tons (9 days)
Primary Crushing	
Normal Feed Rate	540 TPSH
Design Feed Rate	650 TPSH
Feed Size	+ 2" x -10"
Product Size	-2"
Type of Crusher	Double Roll
Redundancy	100% spare
Secondary Crushing	
Normal feed rate	540 TPSH
Design feed rate	650 TPSH
Feed size	-2"
Product Size	-1/4" x 0
Type of Crusher	Single roll
Redundancy	100% spare
Surge Bin	
Purpose	2-1/2 hr storage for final feed to the HRS retort and the CFBC during interrupted supply from crushing plant
Capacity	1350 tons
Dust Control	
Headframe to Lowering Well	Water Sprays
Reclaim from Storage Pile	Baghouses

Weather Protection

Crushers	Closed building (maintained above freezing)
Fine Ore Surge Bin	Closed building (maintained above freezing)
Elevated Transfer House	Roof with open sides
Conveyors	Covered
Control Room and Laboratory	Closed building, heated (68°F) and pressurized

CFBC/Power Generation

The design basis for the steam/power plant incorporates Circulating Fluidized Bed Combustor technology.

Feed Streams

MIS Off-gas	1,008 TPSH
MIS Sour Gas	74 TPSH
HRS Flue Gas	393 TPSH
HRS Fuel Gas	11 TPSH
HRS Spent Shale	338 TPSH
HRS Dirty Water	5 TPSH
Coal	43.5 TPSH

Product Streams

Electric Power	114 Megawatts
600 PSI Steam	278 TPSH
150 PSI Steam	130 TPSH

The compositions of the gas streams are shown on Table 7-1.

The coal analysis is (ultimate analysis, as received):

Coal Analysis

Moisture	10.5%
Carbon	58.44%
Hydrogen	4.14%
Nitrogen	1.17%
Chlorine	0.02%
Sulfur	
Pyretic	0.04%
Organic	0.46%
Sulfate	0.0%
Ash	16.0%
Oxygen	9.23%
Net Heating Value (LHV) ^Δ	10,300 Btu/lb

Above Ground Retorting Facilities

Retort Technology	Lawrence Livermore National Laboratory HRS
Number of Retorts	One
Steady-state Stream Factor	95%
Raw Shale Feed Rate	12,207 TPCD 12,850 TPSD
Shale Properties	
Grade	27 GPT
Size Requirements	-1/4"
Product Recovered	
Recovery (crude oil)	94%
Deashed Shale Oil	7,534 BPCD 7,930 BPSD
Spent shale	10,164 TPCD 10,699 TPSD
AGR Make Gas	332 TPSD
Sour Water	70 TPSD

^Δ Rev 1, 2-5-90

Oil Upgrading Facilities

Hydrotreating Technology	Union Oil
Hydrogen Technology	Natural Gas Reforming with Purification
Feed for H ₂ make	Natural Gas
Sulfur Recovery Technology	Claus w/SCOT Tailgas Unit
Ammonia Recovery Technology	Phosam-W

Oilfeed

BPCD	20,799
BPSD	21,894
API gravity	28.89
Viscosity - CS @ 100°F	[12]
Pour point - °F	[70]
Nitrogen Content	[1.5]
Sulfur Content	[1.2]
Arsenic Content - wppm	[50]

Treated Product

BPCD	[23,125]
BPSD	[24,344]
API gravity	[42]
Viscosity - CS @ 100°F	[< 12]
Nitrogen Content - wppm	{ 100 max }
Sulfur Content - wppm	{ < 5 }
Arsenic Content - wppm	{ < 0.5 }

By-products Recovered

Sulfur - TPCD	25.5
Ammonia - TPCD	76.0

[ ] denotes estimated value;   { } denotes specification

Syncrude Pipeline

Capacity	
BPCD	23,000
GPM	700
Total Length - miles	46
No. Pump Stations	One at Plant Site

Utilities/Offsites

The utility systems that are included in the Case 1, Commercial Plant are:

- Mine Water System
- Cooling Water System
- Inert Gas Generation System
- Instrument and Plant Air System
- Fuel Gas System
- Potable Water System
- Fire Water System
- Service Water System
- Oily/Storm Water System
- Sanitary Sewer System

The offsite facilities that are included in the Case 1, Commercial Plant are:

- Power Distribution
- Interconnecting Pipeways
- Buildings
- Site Preparation and Development
- Mobile Equipment
- Tank Farm
- Rifle Marshalling Yard
- Emergency Flare System
- Control System

CASE 2 and 2A - Demonstration Plant

As noted at the beginning of this section, Case 2/2A incorporates all of the processing units except the oil upgrade facilities and the syncrude pipeline. A block flow diagram of the demonstration size plant is presented in Figure 3-2.

MIS Retort Development and Mining

Mined cross section (ft ²)	165 x 165
Mined height (ft)	278
Mined void (%)	23.0
Rubblized cross section (ft ²)	160.1 x 160.1
Rubblized height (ft)	268
Rubblized plenum height (ft)	10.0
Rubblized void (%)	18.5
Retort volume (ft ³)	7,242,544
Plenum volume (ft ³)	272,250
Rubblized void volume (ft ³)	1,391,500

Rubble rock volume (ft ³)	5,579,860
Average shale rock density (lbs/cu ft)	137.5
Rubblized rock (tons)	384,700
Rubblized Fischer Assay (GPT)	27.0
Oil in place rubblized (Bbl)	247,307

MIS tons mined, with development, per retort (tons)	168,000
MIS tons mined, void only, per retort (tons)	111,500
Mined grade (GPT)	27.0

Production Parameters

Length of work shift (collar to collar)	10 hours
Mine operating shifts	2 shifts per day, 12 shifts per week (1 shift per day on weekends), 3 crews in rotation working 4 shifts per week each
Mine production days	357 days per year (607 shifts per year)
Time between retort ignitions	146 days
MIS tons required to be mined	420,000 per year (168,000 per each of 2.5 retorts, including development)
MIS tons per mine shift	700 tons per shift

Total available operating hours	8 hours per shift (after deducting travel, lunch, and other interruptions)
Productive operating hours	7.6 per shift (efficiency adjusted for 2 shifts per day)

MIS Retorts and Processing Facilities

Retort Technology	Occidental Oil Shale, Inc.	
Steady State Stream Factor	95%	
	<u>Annual Average</u>	<u>Design</u>
Number of burning retorts	2	2
Burning time/Retort-days	292	292
Ignition Cycle days	146	146
Number of retorts burned/year	2.5	2.5
Total Retort Oil Yield	77%	77%
Air Feed Rate/Retort		
SCFM (CD)	11,484	
SCFM (SD)	12,088	
Water Infiltration rate		
per active retort - GPM	25	25
per quench retort - GPM	25	25
Product Streams		
Total MIS Retort Off-gas		
MMSCFD, wet	81.9	86.2
Total Bulkhead Oil		
BPD	871	917
Bulkhead Oil Used as Fuel		
BPD	5	5.3
Bulkhead Oil in Water (lost)		
BPD	26	27
Net Bulkhead Oil Recovered		
BPD	840	884

	<u>Annual Average</u>	<u>Design</u>
Aerosol Oil (with Off-gas) BPD	175	185
Light oil in Off-gas BPD	253	266
Retort Water Total produced in active retort GPM	36.6	40.1
Quench Water Total consumed in spent retort GPM	36.6	40.1
Product Conditions		
Total MIS Retort Off-gas (at surface inlet to Off-gas processing)		
Press., psia	8.5	8.5
Temp., °F	156	156
Bulkhead Oil (at surface) Temp., °F	140	140
Retort Water (at surface) Temp., °F	140	140
MIS Retort Off-gas		
Total Off-gas Composition (vol % dry)		
H ₂	8.17	8.58
N ₂ + Ar	55.35	54.46
O ₂ +	0.14	0.10
CO	2.87	2.96
CO ₂	29.73	30.06
CH ₄	1.20	1.28
C ₂ H ₄	0.09	0.08
C ₂ H ₆	0.28	0.29
C ₃ H ₆	0.09	0.09
C ₃ H ₈	0.11	0.11
C ₄ 's	0.09	0.09
C ₅ 's	0.04	0.04
C ₆ +	0.40	0.45
NH ₃	0.58	0.62

	<u>Annual Average</u>	<u>Design</u>
H ₂ S	0.77	0.77
COS 20 ppm	20 ppm	
CS ₂ 36 ppm	36 ppm	
CH ₃ SH	71 ppm	71 ppm
C ₂ H ₅ SH	71 ppm	71 ppm
Water content, vol %	37.8	39.3
Aerosol Oil API Gravity	39.7	39.7

Off-gas Processing

Off-gas Processing	General Refinery Type Hydrocarbon Processing Technology	
Steady State Stream Factor	95%	

Feed Streams

MIS Retort Off-gas MMSCFD, wet	81.9	86.2
Aerosol Oil BPD	175	185
Stripped Water, GPM		250

Feed Condition

MIS Retort Off-gas, Press., psia	8.5
MIS Retort Off-gas, Temp., °F	156
Stripped Water, Temp., °F	82

Feed Properties Same as MIS Retort Off-gas

Product Streams

Low-Btu Off-gas MMSCFD	49.1	51.7
Foul Water, GPM	348	400

	<u>Annual Average</u>	<u>Design</u>
Aerosol Oil (in foul water) BPD	175	185
Recovered Light Oil BPD	191	200
Total Light Oil Product BPD	366	385
Light Oil Recovery, %	75	75
Product Conditions		
Low-Btu Off-gas, Press., psia		6.95
Low-Btu Off-gas, Temp., °F		50
Foul Water, Temp., °F		120
Recovered Light Oil, Temp., °F		110
Product Properties		
Low-Btu Off-gas Composition (Vol % dry)		
H ₂	8.71	8.71
N ₂ + Ar	55.31	55.31
O ₂	0.10	0.10
CO	3.01	3.01
CO ₂	29.93	29.93
CH ₄	1.30	1.30
C ₂ H ₄	0.08	0.08
C ₂ H ₆	0.29	0.29
C ₃ H ₆	0.09	0.09
C ₃ H ₈	0.11	0.11
C ₄	0.09	0.09
C ₅	0.06	0.06
C ₆ +	0.09	0.09
NH ₃	0.03	0.03
H ₂ S	0.77	0.77

	<u>Annual Average</u>	<u>Design</u>
COS	20 ppm	20 ppm
CS ₂	32 ppm	32 ppm
CH ₃ SH	70 ppm	70 ppm
C ₂ H ₅ SH	<u>66 ppm</u>	<u>66 ppm</u>
	100.00	100.00
LHV, BTU/SCF	69	69
H ₂ O Content, vol % of total	2.5	2.5
Aerosol Oil, API Gravity	39.7	39.7
Recovered Light Oil, API Gravity	51.8	51.8

Off-gas Compression

Feed Stream

Flow		
MMSCFD	49.1	51.7
Pressure - PSIA	7.1	6.95
Temp. - °F	50	50

Product Requirement

Pressure - PSIA	27	27
Temp. - °F	(isentropic Temperature)	

Foul Water Stripping

Feed Stream

Foul water, GPM	348	400
Composition and Conditions, ppmw		
CO ₂	7,481	7,481
NH ₃	3,018	3,018
H ₂ S	136	136
Temperature, °F	145	120
Aerosol Oil, (in foul water) BPD	175	185

Products

	<u>Annual Average</u>	<u>Design</u>
Stripped water, GPM	345	395
Composition, ppmw		
NH ₃	50	50
H ₂ S	8	8
CO ₂	TR	TR
Sour Gas MMSCFD	12.01	12.64
Composition, vol %		
CO ₂	5.41	5.41
NH ₃	5.72	5.72
H ₂ S	0.13	0.13
H ₂ O	<u>88.74</u>	<u>88.74</u>
Total	100.00	100.00
Aerosol Oil		
BPD	175	185
API Gravity	39.7	39.7
Stripping Efficiencies %		
CO ₂	100.0	100.0
NH ₃	98.6	98.6
H ₂ S	95.4	95

Mined Shale Handling and Processing

Mining

Underground Primary Crusher Material	-8" nominal, 20" x 12" x 8" max. lump size
Hoist Schedule	18.5 hrs/stream day
Tons Hoisted per hour (Normal Operating)	80 TPSH
Tons Hoisted per hour (Design)	200 TPSH
Mine Production (days/year)	357 days
Bulk Density of Hoisted Rock	80 lb/cu ft

Fines Present in Hoisted Rock	5%

Rock Surface Moisture	2%

Local Coarse Shale Stockpile

Capacity	243 days storage (239 days dead, 4 days live)

Normal Feed Rate	80 TPSH

Design Feed Rate	200 TPSH

Normal Reclaim Rate	42 TPSH

Design Reclaim Rate	50 TPSH

Live Capacity	6200 tons (4 days)

Dead Capacity	360,000 tons. This represents stockpile from the development of the first two retorts, before theoretical ignition and which is assumed to be worked off during a 10-year life of the project

Primary Crushing

Normal Feed Rate	42 TPSH

Design Feed Rate	50 TPSH

Feed Size	+ 2" x -10"

Product Size	-2"

Type of Crusher	Double Roll

Redundancy	100% spare

Secondary Crushing

Normal feed rate	42 TPSH
Design feed rate	50 TPSH
Feed size	-2"
Product Size	-1/4" x 0
Type of Crusher	Single roll
Redundancy	100% spare

Surge Bin

Purpose	3 hr storage for final feed during interrupted supply from crushing plant
Capacity	150 tons

Dust Control

Headframe to Lowering Well	Water Sprays
Reclaim from Storage Pile to CFBC	Baghouses

Weather Protection

Crushers	Closed building (maintained above freezing)
Fine Ore Surge Bin	Closed building (maintained above freezing)
Elevated Transfer House	Roof with open sides
Conveyors	Covered
Control Room and Laboratory	Closed building, heated (68°F) and pressurized

CFBC/Power Generation

The design basis for the steam/power plant incorporates Circulating Fluidized Bed Combustor technology.

CASE 2

Feed Streams

MIS Off-gas	92 TPSH
MIS Sour Gas	7 TPSH
HRS Flue Gas	30 TPSH
HRS Fuel Gas	0.8 TPSH
HRS Spent Shale	26 TPSH
HRS Dirty Water	0.5 TPSH
Coal	21 TPSH
Limestone	5 TPSH

Product Streams

Electric Power	31 Megawatts
600 PSI Steam	23 TPSH
150 PSI Steam	5.5 TPSH

CASE 2A

Feed Streams

MIS Off-gas	92 TPSH
MIS Sour Gas	7 TPSH
HRS Flue Gas	30 TPSH
HRS Fuel Gas	0.8 TPSH
HRS Spent Shale	26 TPSH
HRS Dirty Water	0.5 TPSH
Coal	4 TPSH

Product Streams

Electric Power	10 Megawatts
600 PSI Steam	23 TPSH
150 PSI Steam	5.5 TPSH

The compositions of the gas streams are shown on Table 7-2.

The coal analysis is (ultimate analysis, as received):

Coal Analysis

Moisture	10.5%
Carbon	58.44%
Hydrogen	4.14%
Nitrogen	1.17%
Chlorine	0.02%
Sulfur	
Pyretic	0.04%
Organic	0.46%
Sulfate	0.0%
Ash	16.0%
Oxygen	9.23%
Net Heating Value	10,300 Btu/lb

Above Ground Retorting Facilities

Retort Technology	Lawrence Livermore National Laboratory HRS

Number of Retorts	One

Steady-state Stream Factor	95%

Raw Shale Feed Rate	950 TPCD 1,000 TPSD

Shale Properties	
Grade	27 GPT
Size Requirements	-1/4"

Product Recovered

Recovery (crude oil)	96%
Deashed Shale Oil	584 BPCD 615 BPSD
Spent Shale	791 TPCD 833 TPSD
AGR Make Gas	26 TPSD
Sour Water	5 TPSD

Utilities/Offsites

The utility systems that are included in the Case 2 Demonstration Plant are:

- Mine Water System
- Cooling Water System
- Inert Gas Generation System
- Instrument and Plant Air System
- Fuel Gas System
- Potable Water System
- Fire Water System
- Service Water System
- Oily/Storm Water System
- Sanitary Sewer System

The offsite facilities that are included in the Case 2, Demonstration Plant are:

- Power Distribution
- Interconnecting Pipeways
- Buildings
- Site Preparation and Development
- Mobile Equipment
- Tank Farm
- Rifle Marshalling Yard
- Emergency Flare System
- Control System

CASE 3 - Pilot Plant

As noted at the beginning of this section, Case 3 incorporates only the materials handling and the HRS above ground retort. A block flow diagram of the pilot size plant is presented in Figure 3-3.

Mined Shale Handling and Processing

The shale feed for the pilot plant will be from an existing stockpile of shale generated during the early mine development work.

Local Coarse Shale Stockpile

Nominal/Rock Size	-8" nominal, 20" x 12" x 8" max. lump size
Bulk Density of Rock	80 lb/cu ft
Fines Present in Rock	5%
Rock Surface Moisture	2%
Normal Reclaim Rate	5 TPSH

Primary Crushing

Normal Feed Rate	5 TPSH
Feed Size	+ 2" x -10"
Product Size	-2"
Type of Crusher	Double Roll
Redundancy	100% spare

Secondary Crushing

Normal Feed Rate	5 TPSH
Feed Size	-2"
Product Size	-1/4" x 0
Type of Crusher	Single Roll
Redundancy	100% spare

Surge Bin

Purpose	2-1/2 hr storage for final feed to the HRS retort during interrupted supply from crushing plant

Dust Control

Storage Pile to Lowering Well Reclaim from Storage Pile	Water Sprays Baghouses

Weather Protection

Crushers	Closed building (maintained above freezing)
Fine Ore Surge Bin	Closed building (maintained above freezing)
Elevated Transfer House	Roof with open sides
Conveyors	Covered
Control Room and Laboratory	Closed building, heated (68°F) and pressured

Above Ground Retorting Facilities

Retort Technology	Lawrence Livermore National Laboratory HRS
Number of Retorts	One
Steady-state Stream Factor	95%
Raw Shale Feed Rate	95 TPCD

	100 TPSD
Shale Properties	
Grade	27 GPT
Size Requirements	-1/4"
Product Recovered	
Recovery (crude oil)	96%
Deashed Shale Oil	58 BPCD
	62 BPSD
Spent shale	79 TPCD
	83 TPSD
AGR Make Gas	3 TPSD
Sour Water	0.5 TPSD
Pneumatic Transport	
Spent Shale	79 TPCD
	83 TPSD
Transport Air	684 MSCFCD
	720 MSCFSD
Quench Water	8.200 Gal/CD
	8,640 Gal/SD
Gas Clean up	
Feeds	Retort Flue Gas Spent Shale
Equipment	
Primary	Cyclone
Secondary	Baghouse

Utilities/Offsites

The required utilities for the Case 3, Pilot Plant, will be supplied to the unit battery limits from existing or temporary facilities.

The temporary offsite facilities that will be provided for the Case 3, Pilot Plant are:

- Power Distribution
- Interconnecting Pipeways
- Buildings
- Site Preparation and Development
- Mobile Equipment
- Tank Farm
- Emergency Flare System
- Control System

Table 3-1
Design Criteria

Basis	Case 1	Case 2/2A	Case 3
<u>Site</u>			
Location	Commercial C-b tract Rio Blanco County	Demonstration C-b tract Rio Blanco County	Pilot C-b Tract Rio Blanco County
<u>Mining Facilities</u>			
Mine type	Shaft Mine	Shaft Mine	
Classification	Gassy-Nonmetal	Gassy-Nonmetal	
Mining Method	-	-	N/A
Oil shale Grade	-	-	
Productions Days	-	-	
Annual Production	0	0	
<u>MIS Retort Development Mining Facilities</u>			
Mining Method	Rm. & Pillar (ea. void level)	Rm. & Pillar (ea. void level)	
Oil Shale Grade			N/A
- mined to AGR/CFBC	27 GPT Average	27 GPT Average	
- rubblized-in-place	27 GPT Average	27 GPT Average	
Production Days	357 Days per Year	357 Days per Year	
Annual Production	4,700,000 Tons	420,000 Tons	
<u>Material Handling Facilities</u>			
Local Coarse Shale Stockpile	37,000 T Live, 13,500 T Dead	4500 T Live, 13,500 T Dead	Coarse shale stockpile from mine development
Remote Coarse Shale Stockpile	3.6 Million Tons	-	
Retort Feed Storage	7,000 Tons (13 hours)		
<u>Aboveground Retort Facilities (AGR)</u>			
Retort Technology	LLNL HRS	LLNL HRS	LLNL HRS
Retort Feed	12,800 TPSD	1000 TPSD	100 TPSD
Feed Shale Grade	27 Gallons per Ton	27 Gallons per Ton	27 Gallons per Ton
Steady State Stream Factor	95%	95%	95%
No. of Retorts	1	1	1

Table 3-1

Design Criteria (Continued)

Basis	Case 1	Case 2/2A	Case 3
<u>Modified in Situ Processing Facilities</u>			
Underground Retorting System			
Retort Technology	Occidental MIS Technology	Occidental MIS Technology	
Retort Processing Rate	22 Retorts Burning Simultaneously 1 Retort Ignited Every 14 Days 27.5 Retorts Processed per Year	2 Retorts Burning Simultaneously 1 Retort Ignited Every 146 Days 2.5 Retorts Processed per Year	N/A
<u>Oil Upgrading Facilities</u>			
Hydrotreating Technology	Union Oil		
Normal Feed Rate	21,894 BPSD (20,799 BPCD)	N/A	N/A
Sulfur Removal Technology	Claus Unit		
Syncrude Production	8.4 Million Barrels per Year		
<u>Syncrude Pipeline Facilities</u>			
Capacity	23,000 BPCD	N/A	N/A
Destination	Chevron Rangely Terminal		
<u>Utilities and Offsite Facilities</u>			
Intermediate and Syncrude Tankage	7 days	15 days storage for light and bulkhead	Drums
Water Source	Mine Inflow supplemented with wells	Mine Inflow supplemented with wells	Mine in flow supplemented with wells
Overcapacity	Minimal	Minimal	Minimal
Power Source	Power generated at site	Power generated at site	Purchased
<u>Coal</u>			
Feed to CFBC, TPD	1044	504/95	
Coal Stockpile, Tons	7000	3400/650	N/A
Feed Storage, Tons	250	50/25	
<u>Capacity of Product/By-Products</u>			
Light Oil, BPCD	-	366	-
Bulkhead Oil, BPCD	-	840	-
Power to Grid, MW	39	25/4	-
Treated Oil, BPCD	23,126	1790*	58*

* Raw untreated shale oil.

Figure 3-1
BLOCK FLOW DIAGRAM
COMMERCIAL SIZE PLANT
CASE 1

Figure 3-2
BLOCK FLOW DIAGRAM
DEMONSTRATION SIZE PLANT
CASES 2, 2A

Figure 3-3
BLOCK FLOW DIAGRAM
PILOT SCALE PLANT
CASE 3

UTILITIES AND OFFSITE FACILITIES

<u>UTILITIES</u>	
3710	Mine Water System
3740	Cooling Water System
3750	Inert Gas Generation System
3760	Instrument & Plant Air System
3770	Fuel Gas System
3780	Potable Water System
3781	Fire Water System
3782	Service Water System
3783	Oily/Storm Water System
3784	Sanitary Sewer System

<u>OFFSITE FACILITIES</u>	
4000	Power Distribution
4100	Interconnecting Pipeways
4200	Buildings
4300	Site Preparation & Development
4400	Mobile Equipment
4530	Tank Farm
4540	Rifle Marshalling Yard
4550	Emergency Flare System
4900	Control System

COSTS

The capital and operating costs for the cases presented in this report are based on criteria, design basis and facilities described in the Design Basis and Process Description sections. These sections summarize the extensive technical information generated during the period 1982 through 1989.

CAPITAL COSTS

The capital costs for the cases are summarized in Table 4-1. The total installed costs for the facility are determined by adding indirect field costs, home office costs, spare parts, sales tax, county tax and unallocated cost/royalties. The accuracy of the estimate is predicted to be +/- 30 percent. The cost basis is mid-1989.

- Mining costs were calculated for the Commercial and the Demonstration facilities by the mining consulting firm of Agapito and Associates, Inc. Copies of the reports are in the appendix.
- A detailed equipment list was generated for the HRS Above Ground Retort (Units 4611, 4612, 4613, 4614). Current pricing is used to determine the mid-1989 costs.
- Oil upgrading Facilities (Area 5000) are essentially the same as before and were adjusted to reflect the amount of oil being processed in Area 5000. A capacity and escalation factor was used to prorate the costs from the 1987 estimate to a mid-1989 basis.
- Shale Handling Facilities (Area 4700) including Coal Handling are based on the flow sketches shown on Figures 7-8, 7-9, and 7-10.
- Utilities and Offsite Facilities (Areas 3700/4000-4500/4900) were adjusted to reflect new balances. A capacity and escalation factor was used to adjust costs from the 1987 estimate which was then escalated to a mid-1989 basis.
- Syncrude Pipeline (Area 4560) costs were modified by using a capacity and escalation factor to update costs from the 1987 estimate.

- The price estimate for the complete CFBC/Power Generation (Area 7000) is based on vendor information.
- The costs for indirect cost, home office costs, spare parts, and state and local tax are calculated as a percentage of direct cost. The percentages used were determined from the 1987 estimate.
- The capitalized unallocated cost and royalties include the Occidental management, engineering, environmental, and accounting staff expenses during the design and construction of the facility. It also includes the ad valorem taxes on improvements on the site as the equipment is installed. In the commercial case, Case 1, it includes the Union Oil hydrotreating royalty as a capitalized lump sum.

OPERATING COSTS

The steady-state operating costs are summarized in Table 4-2 for all of the cases developed in this study. The costs were developed using utility balances, estimates of manpower, estimates of catalyst and chemicals, and historical factors.

- **Natural Gas.** The cost of natural gas is assumed to be \$2.00 per million BTU which reflects the current gas pricing in the area. The consumptions were calculated for each case.
- **Coal.** A small quantity of coal is consumed in the CFBC to provide additional heat for flame stability. This can be clean coal or lower value cleaning plant refuse from nearby coal mines in the Meeker area. For the economic analysis, it has been assumed that local coal mines would furnish the coal at \$1.25/MMBTU delivered by truck from their mine.
- **Electric Power.** Power balances were made for each case. Due to the excess power generated in Cases 1, 2, and 2A, no power is purchased in these cases; in fact these cases generate surplus power for sale. Case 3, the pilot plant, purchases power. Pricing of the purchased power and surplus power is 5 cents per kilowatt hour.
- **Chemicals and Catalyst.** Annual consumptions of catalyst and chemicals were calculated based upon processing requirements. Unit prices were then used to arrive at annual costs.

- **Maintenance Materials.** Annual cost of maintenance materials, maintenance labor and contract maintenance labor was calculated at seven (7) percent of the material cost of the plant facilities.
- **Operating Labor.** Annual operating labor costs were estimated using an average annual rate of \$40,000 per year per laborer. The estimated manpower requirements are shown in Table 4-3.
- **Spent Shale Disposal.** Spent shale disposal costs were scaled annual costs from detailed disposal plans developed in 1984-1985. The costs were scaled upon the quantity of spent shale for disposal.
- **Retort Rubblization and Construction.** The cost to drill and rubblize the MIS retort after it is mined out to the proper void fraction is \$0.5 million per retort. The cost to construct the MIS retort bulkheads and too install the necessary piping and instrumentation is \$1.1 million per retort.
- **Mining Costs.** The mining costs were developed by Agapito & Associates using plans for the demonstration and commercial mines. The costs include all mining labor costs, supplies and equipment. The above costs for electric power and natural gas are included based on the overall utility balance.
- **Unallocated Support.** The unallocated support costs include the administrative and technical staff required to operate the project for each case. Table 4-4 presents a summary of office staffing and expenses and the ad valorem taxes. The ad valorem taxes (property taxes) are estimated at 1.8 percent of the direct field cost of the plant.

PRODUCTS AND BY PRODUCTS

The steady state product and by product production rates, assumed values and annual credits are summarized in Table 4-5.

- **Shale Oil.** The raw shale is credited at \$18.50 per barrel at the plant gate. the hydrotreated syncrude is credited at \$24.50^Δ per barrel at the plant gate. Based upon discussions with Union Oil, syncrude could be worth \$3 to \$6 per barrel more than conventional crude.
- **Electric Power.** The credit for surplus power sales is based upon current avoided costs in Colorado under the Public Utilities Regulatory Policy Act (PURPA). Currently power is

purchased by Public Service of Colorado at 5 cents per kilowatt hour.

- **Sulfur.** The credit for elemental sulfur produced in Case 1 is \$50 per ton based upon U.S. Gulf Coast prices adjusted for shipping charges.
- **Ammonia.** The credit for anhydrous ammonia produced in Case 1 in the wastewater treatment is \$80 per ton based upon current prices in the region.

Table 4-1

CAPITAL COST SUMMARY
(\$ Millions)

AREA/UNIT NUMBER	DESCRIPTION	CASE 1	CASE 2	CASE 2A	CASE 3
--	MINE	148.3	27.0	27.0	0.0
--	MIS RETORT RUBBLIZATION & CONSTRUCTION	34.6	4.2	4.2	0.0
3700	UTILITIES	16.8	5.2	5.2	0.0
4000	POWER DISTRIBUTION	15.7	4.9	4.9	0.0
4100	INTERCONNECTING PIPEWAYS	16.8	4.3	4.3	0.0
4200	BUILDINGS	21.3	13.8	13.8	0.5
4300	SITE PREPARATION & DEVELOPMENT	16.8	5.8	5.8	0.2
4400	MOBILE EQUIPMENT	6.7	2.9	2.9	0.1
4500	TANK FARM, YARD & FLARE	7.8	1.2	1.2	0.0
4560	SYNCRUDE PIPELINE	11.2	0.0	0.0	0.0
4611-14	HRS RETORT, QUENCH, DEASHING & RECYCLE GAS	31.5	11.6	11.6	9.2
4615	FRACTIONATION	9.5	0.0	0.0	0.0
4700	SHALE PREPARATION & HANDLING	6.6	4.0	4.0	0.7
4900	CONTROL SYSTEMS	4.4	1.1	1.1	0.0
5000	OIL UPGRADING FACILITIES	121.0	0.0	0.0	0.0
6000	MIS PROCESS FACILITIES	134.7	23.4	23.4	0.0
7000	CFBC/POWER GENERATION	162.5	52.3	43.6	0.0
TOTAL DIRECT FIELD COST		766.2	161.7	153.0	10.7
INDIRECT FIELD COST		188.7	39.8	37.7	2.6
TOTAL FIELD COST		954.9	201.5	190.7	13.3
HOME OFFICE COST		106.6	22.5	21.3	1.5
TOTAL FIELD AND HOME OFFICE COST		1061.5	224.0	212.0	14.8
SPARE PARTS		7.1	1.5	1.4	0.1
STATE & LOCAL TAXES		25.4	5.4	5.1	0.3
UNALLOCATED COST AND ROYALTIES		68.8	12.6	12.4	4.3
TOTAL PROJECT COST		1162.8	243.5	230.9	19.5

The sunk capital costs expended to-date are not included in the capital costs listed above. 2-4-90

Table 4-2

ANNUAL OPERATING COSTS
(\$ thousands/year)

		Case 1		Case 2		Case 2A		Case 3	
		Usage	Cost	Usage	Cost	Usage	Cost	Usage	Cost
Natural Gas	\$2.00 /MMBTU	702	12,299	11	193	11	193	1	18
Coal	\$1.25 /MMBTU	896	9,811	433	4,741	82	892	0	9 (3)
Electricity	\$0.05 /kwh	0	0	0	0		0	171	75
Diesel Fuel	\$1.25 /gallon		1,115		85		85		5
Raw Water	\$250 /ac-ft	3055	361	145	0	145	0	61	30 (4)
Catalysts and Chemicals			7,600		29		29		0
Operating Labor		343	13,720	150	6,000	150	6,000	92	2,208 (5)
Maintenance Material & Labor			20,515		4,330		4,097		286
Spent Shale Disposal			300		27		27		24
Retort Rubblization & Construction			44,324		4,708 (2)		4,708 (2)		0
Mining			42,942		5,920 (2)		5,920 (2)		0
Unallocated Support			25,051		8,541		8,314		2,305
			-----		-----		-----		-----
			178,039		34,574		30,265		4,960

Notes:

1. Does not include income taxes or Federal lease royalties.
2. First year of operation costs. Retort rubblization complete in two years of operation and retort construction in four years. Mining costs decrease for next two years as mining of retorts is completed.
3. Cost to dig and crush shale for feedstock.
4. Costs for raw water and for a steam boiler and water treating.
5. Cost for contract operators and maintenance for 1/2 year.

Table 4-3

ESTIMATED MANPOWER REQUIREMENTS *

AREA DESCRIPTION	Case 1	Case 2	Case 2A	Case 3
Process Operators				
Hoisting & Materials Handling	28	20	20	8
Above Ground Retorting	20	12	12	16
MIS: Surface	40	12	12	--
MIS: Underground	24	12	12	--
CFCB and Generator	8	8	8	--
Oil Upgrading	16	--	--	--
Offsites and Utilities	12	8	8	8
Relief	12	10	10	6
Total Operators	160	82	82	38
Operations Supervision	40	8	8	8
Maintenance Labor				
Hoisting & Materials Handling	21	6	6	8
Above Ground Retorting	24	10	10	16
MIS: Surface	24	6	6	--
MIS: Underground	12	6	6	--
CFCB and Generator	8	8	8	--
Oil Upgrading	24	--	--	--
Offsites and Utilities	10	6	6	8
Site Maintenance	10	10	10	10
Total Maintenance Labor	133	52	52	42
Maintenance Supervision	10	8	8	4
Total Operators and Maintenance	343	150	150	92

* These manpower requirements do not include the office personnel listed in Table 4-4, Unallocated Support Cost, or the miners. There will be 273 miners for Case 1 and 74 miners for Cases 2 and 2A. There are no miners required for Case 3, the pilot plant.

Table 4-4

UNALLOCATED SUPPORT COSTS

(Office Salaries and Expenses plus Ad Valorem Taxes)
(\$ thousands per year)

	Unit Salary \$k/yr	Commercial Plant		Demonstration Plant				Pilot Plant	
		Case - 1 No.	\$k/yr	Case - 2 NO.	\$k/yr	Case - 2A NO.	\$k/yr	Case - 3 NO.	\$k/yr
President	150	1	150	1	150	1	150	1	150
Secretary	30	1	30	1	30	1	30	1	30
Project Director	115	1	115	1	115	1	115		0
Technical Manager	100	1	100	1	100	1	100		0
Chemical Engineers	70	2	140	2	140	2	140	1	70
Mechanical Engineers	65	2	130	2	130	2	130	1	65
Electrical Engineers	65	1	65	1	65	1	65		0
Mine Engineers	60	2	120	1	60	1	60		0
Blasting	95	1	95	1	95	1	95		0
Geologist	70	1	70	1	70	1	70		0
Construction Manager	90	1	90	1	90	1	90		0
Project Engineer	60	2	120	1	60	1	60	1	60
Environmental Manager	75	1	75		0		0		0
Air	60	1	60	1	60	1	60	1	60
Water	40	2	80	1	40	1	40		0
Reporting	40	1	40	1	40	1	40	1	40
Samplers	35	4	140	4	140	4	140	2	70
Health & Safety	50	1	50	1	50	1	50	1	50
Inspectors	40	3	120	3	120	3	120		0
Accounting Manager	85	1	85	1	85	1	85		0
Accountants	40	2	80	2	80	2	80	1	40
Payroll	30	2	60	1	30	1	30		0
Personnel Administration	60	1	60	1	60	1	60		0
Clerk	20	2	40	1	20	1	20	1	20
Secretaries	25	4	100	3	75	3	75	2	50
Legal	100	1	100	1	100	1	100		0
Public Affairs	55	1	55	1	55	1	55		0
Laboratory									
Chief Chemist	75	1	75	1	75	1	75	1	75
Chemists	50	2	100	1	50	1	50	2	100
Total Direct Payroll Expense		46	2545	38	2185	38	2185	17	880
Salary fringe and Benefits		45%	1145.2		983.25		983.25		396
Total Wages and Benefits			3690.2		3168.2		3168.2		1276
Office Expense			500		500		500		250
Travel Expense			250		250		250		200
Corporate Charges									
Bonds & Insurance			600		400		400		300
Subtotal			5040.2		4318.2		4318.2		2026
Ad Valorem Taxes			20011		4222		3996		279
Total			25051		8541		8314		2305

Table 4-5

PRODUCTS AND BY-PRODUCTS
Production Rates and Revenues

	Case 1		Case 2		Case 2A		Case 3	
	Rate	Revenue \$ k/Yr	Rate	Revenue \$ k/Yr	Rate	Revenue \$ k/Yr	Rate	Revenue \$ k/Yr
Oil								
Raw Shale Oil, B/CD @ \$18.50/bbl			1,790	12,087	1,790	12,087	58	65
Syn Crude, B/CD @ \$24.50/bbl	23,126	206,804					**	
Electric Power								
Net, kw-hr/hr @ \$0.05/kwh	43,293	18,962	25,244	11,057	4,344	1,903		
Sulfur								
Metric Tons/CD @ \$50.00/ton	23	422						
Anhydrous Ammonia								
Tons/CD @ \$80.00/TON	76	2,219						
TOTAL REVENUES		228,408		23,144		13,990		65

** Pilot plant operation will produce 2 months of rated capacity of oil.

SCHEDULE

CASE 1 - COMMERCIAL PLANT

The Commercial plant schedule is expected to require six years from kickoff to completion of the commissioning and startup activities. The project schedule is shown in Figure 5-1.

CASE 2/2A - DEMONSTRATION PLANT

The Demonstration plant schedule is expected to require four years from kickoff to completion of the commissioning and startup activities. The project schedule is shown in Figure 5-2.

CASE 3 - PILOT PLANT

The Pilot plant schedule is expected to require three years from kickoff to completion of the construction activities. The project schedule is shown in Figure 5-3.

If process development on the three cases is done sequentially, the overall schedule would be approximately 15 years. This allows the Pilot and Demonstration plants one year each of operation before design of the next size facility. A more economical alternate to straight sequential activities is an integrated Pre-commercialization schedule.

PRE-COMMERCIALIZATION PLAN

The Pre-commercialization plan, which integrates the schedules of the Pilot and Demonstration Plants, and takes into account the advanced readiness of the MIS retort, will take a total of 10 years. This integrated schedule would allow for a faster startup of the MIS Commercial size plant and accommodate the longer development schedule for the HRS process. The project schedule for the Pre-commercialization plan is presented in Figure 5-4.

Figure 5-1

PROJECT SCHEDULE
CASE 1 - COMMERCIAL

Figure 5-2
PROJECT SCHEDULE
CASE 2 AND 2A - DEMONSTRATION

Figure 5-3
PROJECT SCHEDULE
CASE 3 - PILOT PLANT

Figure 5-4

PRE-COMMERCIALIZATION SCHEDULE

ECONOMIC ANALYSIS

SUMMARY

Financial analyses have been conducted for the commercial case, demonstration case and pilot plant case, Cases 1 to 3 respectively.

For the commercial case, Case 1, the financial analyses have generated oil prices in 1989 dollars required to produce an acceptable rate of return on the investment. For a 24,000 BPD plant, an oil price of \$23.35 per barrel will yield a 20 percent IRR for the financial assumptions of the model. This price can be interpreted as a per barrel oil price which generates enough revenue for the project to recover project costs including return on equity capital and debt service. These economics provide a first test of commercial project economics.

For the demonstration case and pilot plant case, the construction and operating costs for each program were developed for the complete program. The demonstration program is a 10 year program which totals \$206.6 million to construct the plant and operate it for seven years. If oil or electricity prices increase over inflation, the cost of the demonstration program decreases. The pilot program is a 4 year program to construct the pilot plant and operate it for one year to gather sufficient data to scale up the technology. The cost of the pilot program is \$18.0 million.

FINANCIAL ANALYSES

Using 1989 dollar estimates of capital and operating costs, the financial simulations determine the as spent cash flow requirements of the three cases. For the commercial case, the 1989 dollar oil price required to yield a target after tax return on equity was calculated for various assumptions.

Commercial Case

For the commercial facility, Case 1, the financial results are summarized in Figure 6-1 and Table 6-1. Figure 6-1 shows the current oil price required to achieve returns on equity between 5 and 30 percent. The curves assume a financing structure of 75 percent debt and 25 percent equity, a 10 percent interest rate on debt and a 37.3 percent composite federal and state income tax rate. Curves were developed for oil prices increasing with inflation (at no real growth) and inflation plus two percent per year real

growth. The required oil prices to yield a 20 percent return on equity are:

\$29.35/Barrel at 0% Real Growth
\$23.35/Barrel at 2% Real Growth.

These oil prices are at the pipeline terminal and exclude transportation cost to a final destination. There is also no premium quality credit assumed for the hydrotreated syncrude which could be between 3 to 6 dollars per barrel.

A cash flow projections for the commercial case are included in Tables 6-1 and 6-2.

Demonstration Case

For the demonstration and pilot plant cases, Cases 2, 2A and 3, the capital and operating costs in 1989 dollars were escalated during the construction and operating periods. Tables 6-3, 6-4, and 6-5 show the as spent cash flow requirements of these programs. The cumulative cash flow requirements are summarized below.

	\$ Millions (As Spent)	
	Before Tax	After Tax
Case 2 Demonstration	-318.4	-206.6
Case 1 Pilot	-27.9	-18.0
Pre-commercialization	-330.0	-213.4

The demonstration program would provide a demonstration of the MIS technology on a continuous basis and a large scale demonstration of the LLNL retorting concept.

ECONOMIC EVALUATION ASSUMPTIONS

The analyses are based on the assumptions summarized in the tabulation on the following page and discussed in the paragraphs following this table.

The sunk capital cost expended to date are not included in the economic analysis consideration. Δ 2-5-90

SUMMARY OF ECONOMIC EVALUATION ASSUMPTIONS

	Demonstration	Commercial	Pilot
Time basis for cost estimates	1989	1989	1989
Annual inflation rates (escalation), %	5	5	5
Annual debt cost (interest rate), %	None	10	None
Federal income tax rate, %	34	34	34
State income tax rate, %	5	5	5
Book life, years	7	25	1
Operating capacity factor, %	90-95	90-95	20-25
Depreciation tax life, years	7	7	1
Depreciation option	Double declining balance	Double declining balance	
Construction time, years	3	5	2

Timing

The construction and operating period is: 4 years for the pilot case, 10 years for the demonstration case and 30 years for the commercial case.

Cash flows are assumed to occur at mid-year.

The cash flows are based on as-spent dollars; the required oil price results are expressed in constant mid-1989 dollars.

Return on Equity

Return on equity investment is computed as a discounted internal rate of return assuming a consolidated corporate return, using tax benefits as generated.

Tax Considerations

All capital equipment is assumed to have a seven-year useful life under the Tax Reform Act of 1986, except the pilot plant which is used only one year.

Tax depreciation was calculated using the double declining balance factors presented below:

Year	Percent	Year	Percent
1	14.3	5	8.9
2	24.5	6	8.9
3	17.5	7	8.9
4	12.5	8	4.4

Depreciation was assumed to begin when the equipment was ready to perform. The depreciation was calculated on one-half of the current year's and the previous years' investments.

In the commercial cases, preproduction costs are capitalized through start of operations and are expensed over the operating life of 25 years. Interest during construction is capitalized.

The mineral depletion allowance is the lesser of 15 percent of mining revenues or 50 percent of taxable income before depletion.

The effective combined state and federal income tax rate is assumed to be 37.3 percent, based on 5 percent state and 34 percent federal income tax rates.

Federal Royalty_____

The Federal lease royalty was based upon the actual tonnage of material mined and adjusted for grade and current oil price.

Debt Repayment_____

In the commercial projects, project financing was assumed at 75 percent debt and 25 percent equity. The demonstration cases were run at 100 percent equity since a demonstration case could probably not be financed on a project basis.

For the commercial cases, debt repayment was assumed to take place as a lump-sum payment after 25 years of operation.

CASH FLOW PROJECTIONS - 0% REAL GROWTH
(\$ millions as spent)

[illegible]

CASH FLOW PROJECTIONS - 0% REAL GROWTH
(\$ millions as spent)

[illegible]

Commercial Plant - Case 1

[illegible]

Table 6-2

CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ millions as spent)

	Commercial Plant - Case 1										
YEAR	0	1	2	3	4	5	6	7	8	9	10
PRODUCTION AND PRICES:											
OIL PRODUCTION,MMBBL/YR	0	0	0	0.422049	4.220495	7.174841	8.44099	8.44099	8.44099	8.44099	8.44099
ANNUAL OIL PRICE	23.35	25.01	26.78	28.69	30.72	32.90	35.24	37.74	40.42	43.29	46.36
CASH FLOW:											
OIL REVENUES	0.0	0.0	0.0	12.1	129.7	236.1	297.5	318.6	341.2	365.4	391.4
BY-PRODUCT CREDITS	0.0	0.0	0.0	0.0	10.5	20.7	29.0	30.4	31.9	33.5	35.2
REVENUES	0.0	0.0	0.0	12.1	140.2	256.8	326.4	349.0	373.1	398.9	426.5
O AND M COSTS	0.0	0.0	0.0	4.0	50.1	221.3	248.3	262.4	346.4	289.4	304.0
INTEREST EXPENSE						7.0	128.1	128.1	128.1	128.1	128.1
NET OPERATING INCOME	0.0	0.0	0.0	8.1	90.1	28.5	-50.0	-41.5	-101.4	-18.6	-5.6
TAX DEPRECIATION	0.0	10.9	47.4	127.6	228.6	279.1	256.0	205.0	162.6	135.4	102.8
DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EARNINGS BEFORE TAX	0.0	-10.9	-47.4	-119.5	-138.5	-250.6	-306.1	-246.5	-263.9	-154.0	-108.3
INCOME TAXES	0.0	-4.1	-17.7	-44.6	-51.7	-93.5	-114.2	-91.9	-98.4	-57.4	-40.4
EARNINGS AFTER TAX	0.0	-6.8	-29.7	-74.9	-86.8	-157.1	-191.9	-154.5	-165.5	-96.6	-67.9
+ TAX DEPRECIATION	0.0	10.9	47.4	127.6	228.6	279.1	256.0	205.0	162.6	135.4	102.8
+ DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- EQUITY COSTS	0.0	38.0	63.5	176.6	99.6	49.3	0.0	0.0	0.0	0.0	0.0
- REPLACEMENT COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- INCREASE WORKING CAP	0.0	0.0	0.0	7.4	22.3	10.8	5.4	2.7	-2.9	9.1	3.4
NET CASH FLOW	0.0	-33.9	-45.8	-131.3	19.9	61.9	58.7	47.7	0.0	29.8	31.5
CUM. NET CASH FLOW	0.0	-33.9	-79.7	-211.0	-191.2	-129.3	-70.6	-22.8	-22.8	6.9	38.4

CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ millions as spent)

[illegible]

**CASH FLOW PROJECTIONS - 2% REAL GROWTH
(\$ MILLIONS AS SPENT)**

[illegible]

Table 6-3

CASH FLOW PROJECTIONS
(\$ millions as spent)

Demonstration Plant - Case 2

YEAR	0	1	2	3	4	5	6	7	8	9	10	Total
PRODUCTION AND PRICES:												
OIL PRODUCTION,MMBBL/YR	0.00	0.00	0.00	0.03	0.62	0.65	0.65	0.65	0.65	0.65	0.65	4.6
ANNUAL OIL PRICE	18.50	19.43	20.40	21.42	22.49	23.61	24.79	26.03	27.33	28.70	30.13	
CASH FLOW:												
OIL REVENUES	0.0	0.0	0.0	0.7	14.0	15.4	16.2	17.0	17.9	18.8	19.7	119.6
BY-PRODUCT CREDITS	0.0	0.0	0.0	0.6	12.8	14.1	14.8	15.6	16.3	17.2	18.0	109.4
REVENUES	0.0	0.0	0.0	1.3	26.7	29.5	31.0	32.6	34.2	35.9	37.7	229.0
O AND M COSTS	0.0	0.0	0.0	8.9	42.3	42.7	36.1	34.7	36.0	36.6	38.0	275.2
INTEREST EXPENSE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET OPERATING INCOME	0.0	0.0	0.0	-7.6	-15.5	-13.2	-5.0	-2.2	-1.8	-0.7	-0.3	-46.3
TAX DEPRECIATION	0.0	3.6	15.6	35.3	50.2	47.0	35.3	27.5	23.4	19.1	15.1	272.2
DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EARNINGS BEFORE TAX	0.0	-3.6	-15.6	-42.9	-65.7	-60.2	-40.3	-29.6	-25.2	-19.8	-15.4	-318.4
INCOME TAXES	0.0	-1.4	-5.8	-16.0	-24.5	-22.4	-15.0	-11.1	-9.4	-7.4	-5.8	-118.8
EARNINGS AFTER TAX	0.0	-2.3	-9.8	-26.9	-41.2	-37.7	-25.3	-18.6	-15.8	-12.4	-9.7	-199.6
+ TAX DEPRECIATION	0.0	3.6	15.6	35.3	50.2	47.0	35.3	27.5	23.4	19.1	15.1	272.2
+ DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- EQUITY COSTS	10.0	40.6	80.5	126.8	14.8	0.0	0.0	0.0	0.0	0.0	0.0	272.8
- DEBT REPAYMENT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- REPLACEMENT COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- INCREASE WORKING CAP	0.0	0.0	0.0	0.9	4.9	0.3	-0.4	0.0	0.2	0.2	0.3	6.3
NET CASH FLOW	-10.0	-39.3	-74.7	-119.3	-10.7	9.0	10.4	8.9	7.4	6.5	5.2	-206.6
CUM. NET CASH FLOW	-10.0	-49.3	-124.0	-243.3	-254.0	-245.0	-234.6	-225.7	-218.3	-211.8	-206.6	

Table 6-4

CASH FLOW PROJECTIONS
(\$ millions as spent)

Demonstration Plant - Case 2A

YEAR	0	1	2	3	4	5	6	7	8	9	10	Total
PRODUCTION AND PRICES:												
OIL PRODUCTION,MMBBL/YR	0.00	0.00	0.00	0.03	0.62	0.65	0.65	0.65	0.65	0.65	0.65	4.6
ANNUAL OIL PRICE	18.50	19.43	20.40	21.42	22.49	23.61	24.79	26.03	27.33	28.70	30.13	
CASH FLOW:												
OIL REVENUES	0.0	0.0	0.0	0.7	14.0	15.4	16.2	17.0	17.9	18.8	19.7	119.6
BY-PRODUCT CREDITS	0.0	0.0	0.0	0.1	2.2	2.4	2.5	2.7	2.8	3.0	3.1	18.8
REVENUES	0.0	0.0	0.0	0.8	16.2	17.9	18.7	19.7	20.7	21.7	22.8	138.4
												0.0
O AND M COSTS	0.0	0.0	0.0	6.5	37.0	37.9	32.2	32.4	29.6	29.9	31.0	236.6
INTEREST EXPENSE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET OPERATING INCOME	0.0	0.0	0.0	-5.7	-20.8	-20.1	-13.5	-12.7	-8.9	-8.2	-8.2	-98.1
TAX DEPRECIATION	0.0	3.4	14.7	33.3	47.3	44.4	33.3	25.9	22.1	18.1	14.3	256.8
DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EARNINGS BEFORE TAX	0.0	-3.4	-14.7	-39.1	-68.2	-64.4	-46.8	-38.6	-31.0	-26.3	-22.5	-355.0
INCOME TAXES	0.0	-1.3	-5.5	-14.6	-25.4	-24.0	-17.4	-14.4	-11.6	-9.8	-8.4	-132.4
EARNINGS AFTER TAX	0.0	-2.1	-9.2	-24.5	-42.8	-40.4	-29.3	-24.2	-19.5	-16.5	-14.1	-222.6
+ TAX DEPRECIATION	0.0	3.4	14.7	33.3	47.3	44.4	33.3	25.9	22.1	18.1	14.3	256.8
+ DEPLETION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- EQUITY COSTS	10.0	37.8	76.0	119.7	14.0	0.0	0.0	0.0	0.0	0.0	0.0	257.4
- DEBT REPAYMENT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- REPLACEMENT COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
- INCREASE WORKING CAP	0.0	0.0	0.0	0.6	3.8	0.2	-0.4	0.1	-0.2	0.1	0.2	4.5
NET CASH FLOW	-10.0	-36.5	-70.5	-111.5	-13.2	3.8	4.4	1.6	2.8	1.5	0.0	-227.7
CUM. NET CASH FLOW	-10.0	-46.5	-117.0	-228.5	-241.7	-237.9	-233.6	-232.0	-229.2	-227.7	-227.7	

Pilot Plant - Case 3

[illegible]

Figure 6-1
COMMERCIAL SHALE OIL ECONOMICS
IRR vs OIL PRICE - Case 1

PROJECT DESCRIPTION

This section describes the mining system and the processing facilities that will be used to produce oil and by-products.

SITE DESCRIPTION

Federal Oil Shale Tract C-b is located in the Piceance Creek basin between the Colorado River on the south and the White River on the north. The basin is dominated by a large central plateau, which represents more than 75 percent of the basin's land surface. The area represents a sparsely populated portion of Rio Blanco County in northwestern Colorado. Terrain on the tract consists primarily of undulating valleys and ridges trending in a northeasterly direction and draining into Piceance Creek. The northern edge of the tract is approximately 0.5 mile south of Piceance Creek between Willow Creek and Stewart Gulch. West of the tract, Piceance Creek flows northwesterly approximately 24 miles to its confluence with the White River. Irrigated-grassland ranching predominates along Piceance Creek. The towns nearest the tract are Meeker (48 miles), Rifle (45 miles), and Rangely (65 miles).

The location of the tract relative to other existing and proposed oil shale projects in northwestern Colorado is shown in Figure 7-1. The tract, as legally described in U.S. Department of the Interior Oil Shale Lease C-20341, consists of 5,094 acres, more or less, which is shown in Figure 7-2 and is located in Rio Blanco County, Colorado, as follows:

T3S, R96W, 6th P.M.

Section 5, W 1/2, SE 1/4, and SW 1/4
Section 6, lots 6 and 7, E 1/2, SW 1/4, and E 1/2
Section 7, lots 1, 2, 3 and 4, E 1/2, W 1/2, and E 1/2
Section 8, W 1/2, NE 1/4, NW 1/4, NW 1/4, and S 1/2
Section 9, SW 1/4
Section 16, NW 1/4, and W 1/2, SW 1/4
Section 17
Section 18, lots 1, 2, 3, and 4, E 1/2, W 1/2, and E 1/2

T3S, R97W, 6th P.M.

Section 1, S 1/2
Section 2, SE 1/4
Section 11, E 1/2

Section 12
Section 13, N 1/2
Section 14, N 1/2, NE 1/4

MINE PLAN

Typical MIS Retort Design

Results of an extensive research and development program by Occidental at the Logan Wash Mine Site form the basis for the MIS retort design used in this study. A MIS mining isometric is shown in Figure 7-3.

The underground retort will be the basic production unit for the modified in-situ method. A retort will be a rectangular column of fragmented shale with a uniform particle size distribution. Each retort will be 165 ft. square by 270 ft. high. A retort will be created by:

- Mining void rooms.

A total of 23 percent of the overall retort volume will be removed by excavating shale from three separate levels; upper, intermediate, and lower. The mined rooms on the upper and lower levels will be 19 ft. high. On each of these levels, two pillars 17 ft. X 115 ft. will be left to support the roof. The excavated opening on the intermediate level will be 42 ft. high, with a central pillar 60 by 90 ft. left for support.

- Drilling Blastholes.

Vertical blastholes will be drilled into the retort block from the upper and intermediate void rooms. Horizontal blastholes will be drilled into the support pillars on the three levels.

- Rubblization.

All blastholes will be loaded with conventional explosives, or blasting agents primed with delay detonators, and stemmed. Rubblization of a retort will be a "one shot" sequential blast which will begin with the blasting of pillars followed by the explosive expansion of shale into void rooms.

Having created a retort, it will be ignited at the upper level, and burned by air injection so that the flame front moves slowly down through the permeable rubblized mass with the resulting gas and oil products flowing out at the haulage level.

A retort contains 385,000 tons of retortable shale averaging 27 gallons per ton. Average yield of 80 percent is expected, giving a total yield of approximately 198,000 barrels per retort.

General Mine Layout

Mining activities can be divided into two categories: preproduction mining and production mining. Preproduction mining will include all the development and excavations within the mine pillar area. Production mining will include all mining outside the mine pillar.

The mine pillar will serve as a buffer zone from the possible influence resulting from mine subsidence. All shafts and all underground mine support facilities will be located within the mine pillar. Also included within the mine pillar will be the drifts and boreholes necessary for the off-gas handling system.

The production portion of the mine will be broken down into a system of panels. Each panel will contain a number of clusters. Panels will be accessed through a double-entry system of panel drifts. A cluster contains five retorts and will be the basic building block of the mine layout. The mining system will be an advancing system starting with the first cluster in the southern end of Panel 1 and working north. Adjacent panels will be developed in sequence until the western boundary is reached. Mining will progress from the mine pillar to the east and southeast according to expansion phase development plans.

There will be three major mining levels: upper void, intermediate void, and lower void. Shaft stations will be located on each level. Warehouse and shops will be located on the intermediate and lower levels. A system of ramps within the mine pillar will connect at all levels.

A system of ore passes and ventilation raises in the panels will provide ventilation paths between the mining levels and will provide for transfer of mined shale to the conveyor levels. All mined material is conveyed to the production shaft for hoisting.

Overall Plot Plan

The plot plan for the C-b tract is shown on Figure 7-4.

GENERAL PROCESS FACILITY DESCRIPTION

Case 1: The facilities include underground retorts and retort development; underground retorting, above ground MIS gas processing and compression; foul water stripping; surface shale

processing, coal receiving, storage and handling of feed to the CFBC; CFBC/power generation; above ground retort facilities; oil upgrading facilities; and utilities/support facilities. The Case 1 facility will produce oil and excess power. Figure 7-5 and Table 7-1 show the arrangement of the process facilities for Case 1 and the material balance based on steady-state operation of twenty-two retorts burning simultaneously.

Case 2. The facilities include underground retorts and retort development; underground retorting, above ground MIS gas processing and compression; foul water stripping; surface shale processing, coal receiving, storage and handling of feed to the CFBC; CFBC/power generation; above ground retort facilities; and utilities/support facilities. The Case 2 facility will produce oil and excess power. Figure 7-6 and Table 7-2 show the arrangement of the process facilities for Case 2 and the material balance based on steady-state operation of two retorts burning simultaneously.

Case 3. The facilities include surface shale processing and the HRS above ground retort. Figure 7-7 and Table 7-3 show the arrangement of the process facilities for Case 3 and the material balance based on steady-state operation.

The units described in this section include:

- MIS Retort and Processing Facilities
- Mined Shale Handling and Processing
- CFBC/Power Generation
- Above Ground Retorting
- Oil Upgrading
- Syncrude Pipeline
- Utilities and Offsites

MIS Retorting and Processing Facilities

MIS retorting comprises the following operations:

- Underground retorting and oil recovery
- Off-gas processing to recover light oil from the gas and clean the gas of foul components

- Off-gas compression to draw the gas through the MIS retort and gas processing system and to overcome the backpressure of the boilers and other downstream systems
- Purification of foul water generated in off-gas processing

Underground Retorting. The MIS retorts operate in sequence. Once steady state is reached with two retorts in operation, a new retort will be started up and an exhausted retort will be shut down every 146 days. The exhausted retort, after shutdown, goes through a quench cycle that lasts roughly 10 months.

Retort Construction. Bulkheads must be constructed to isolate and seal individual retorts from adjacent retorts. Steel plate bulkheads reinforced with structural steel members are installed at all retort openings to the mine. The steel plates are welded to rock bolts installed on both sides and on top of the drift. The peripheral area between the plate, the side, and the top of the drift is shotcreted to provide the final air seal. Insulation is provided to protect the steel plate.

Ignition. The objective of the ignition phase is to establish a nearly uniform combustion zone across the whole retort. Ignition or startup of a retort requires the following actions:

- Purging the air (oxygen) from the retort rubble voids into the off-gas ducts in a safe manner
- Rapid and uniform heating of the top surface of the rubble column to the temperature at which combustion will occur, using hot inert gas
- Introducing air to initiate and establish the combustion zone

A retort is ignited every 14 days (Case 1). The hot inert gas generator (HIGG) will be used for ignition and pre-ignition to purge the retort of oxygen. The retort startup requires the HIGG to produce inert gas with an oxygen concentration less than 0.5 percent. The combined off-gas from all retorts will be maintained below the oxygen content of four percent during retort startup.

When the purge step is completed, the HIGG firing rate is increased. It takes approximately 18 hours to bring the surface of the rubble to the ignition temperature. At this point, excess air is introduced through the HIGG and combustion commences on the surface of the rubble. The plenum acts as a mixing zone, resulting in uniform temperatures over the surface of the rubble.

Oil Production and Recovery. The shale oil will condense as it flows down through the rubblized shale. The liquid flows to the bottom of the retort and is collected inside the bulkhead at the product drift. The off-gas and liquid oil are drawn from the mined lower void level to a product collection drift.

The primary separation of the bulkhead oil and retort water occurs in the product drift behind the bulkhead. Bulkhead oil is pumped to the central compartment of the oil/water separator tank for further separation. A demulsifier is added to the suction of the oil/water pump or behind the bulkhead to promote oil/water separation.

Bulkhead oil from the oil/water separation tank is pumped to the retort oil tank on the surface. Retort water is utilized for retort bulkhead sprays and quench, or is pumped to the retort water tank on the surface.

The off-gas from each retort is piped to a collection system and ultimately to the off-gas raise to the surface processing facilities.

During the later stages of retorting, water recirculated from the surface facilities and from the bottom of the liquid pool behind the bulkhead compartment is sprayed into the vapor phase of the compartment behind the bulkhead. This permits cooling of the gas and allows retorting to go to completion to yield maximum recovery of oil.

Spent Retort Management. A retort contains over 100,000 MMBtu's of energy in hot spent shale at the end of the retorting cycle. This energy must be removed to prevent heat degradation of retort pillars. Water distributed over the top of the retort evaporates, cooling the retort and purifying the quench water which exits as a vapor. The water will be consumed by the water gas reaction, in calcium and magnesium slaking, and spent shale wetting. The water gas shift reaction occurs at high temperatures early in the quench phase. Slaking and wetting occur following the cooling of the shale to approximately 200°F at which point the water will react as a liquid.

The quench operation of each retort will last approximately 10 months. It will improve the off-gas heating value, clean process water, and complement the overall process water balance by consuming low-quality water.

Off-gas Processing. Processing of the MIS off-gas stream consists of (1) cooling the gas to remove water vapor and aerosol oil, (2) scrubbing it with stripped water to remove ammonia, (3) refrigerating and scrubbing it with a sponge oil to recover valuable

hydrocarbon products and (4) compressing the gas to boiler feed pressure requirements.

The cleaned gas is burned in the CFBC. The ammoniated water is stripped of all volatile constituents and used elsewhere in the process.

Refrigeration is produced in an ammonia/water absorption system, utilizing low level heat in the form of 85 psig steam.

Cooling and Ammonia Recovery. Off-gas from the MIS retorts at 156°F and 8.5 psia enters near the bottom of the direct contact condenser, a tower with five contact sections; one spray and four packed. Cooled stripped water at 82°F is fed to the top of the second (from the bottom) 15-foot packed section where final traces of ammonia are removed from the MIS gas. The water flows downward to the first (lower) packed section where the main gas cooling and bulk ammonia removal takes place. Heat removal is accomplished with a pump-around loop around this first packed section. Water vapor and some aerosol oil mist are condensed in this lower section.

Excess water and any oil from the pump-around loop at 120°F are sprayed into the bottom section of the tower which performs some cooling of the incoming gas stream and condenses the bulk of the aerosol oil. All oil and water from this spray section falls to the bottom of the tower where the two phases separate and flow to their respective compartments. The aqueous phase consisting of foul water is pumped to the foul water stripper unit. The oily phase is pumped to the aerosol settling tank where it is separated into water and oil phases.

Light Oil Recovery. The cleaned, cooled gas from the top of the second packed section enters the bottom of the third packed section, where it is further cooled to 50°F by a pump-around loop of refrigerated sponge oil. The pump-around loop is refrigerated to hold the bottom of the packed section temperature at 50°F. Here some of the heavier hydrocarbons in the gas stream as well as additional water are condensed. The cooled gas stream enters the fourth (top) packed section countercurrent to a lean (regenerated) cold sponge oil stream which absorbs most of the C5+ compounds. The lean sponge oil is composed of the heavier ends of the recovered hydrocarbons. The lean sponge oil feed is at 42°F to permit maintenance of the 50°F as it drops onto the third packed section thus providing some refrigeration to the pump-around loop. A withdrawal, equal to feed sponge oil plus absorbed hydrocarbons, is made from the warm end of the pump-around loop.

Lean gas at 50°F and approximately 7.3 psia is sent to the off-gas compression unit.

The rich oil withdrawn from the pump-around loop is pumped through a coalescer, heated against lean sponge oil, and distilled in the sponge oil fractionator. A light naphtha overhead and lean oil bottom are produced in the fractionator. The former is stabilized by flashing to a slight vacuum. The flash gases are pumped to the MIS gas header. Most of the lean oil is recycled to the absorber as lean sponge oil, but a small fraction is withdrawn and combined with the stabilized naphtha overhead. The stream of hydrocarbons removed from the off-gas in the top two packed sections of the direct contact/condenser is combined with the oil recovered from the aerosol settling tank and the foul water stripper surge tank and is sent to the retort oil tank.

Foul water streams from the aerosol settling tank, coalescer and splitter overhead accumulator are combined with the water phase from the direct contact condenser and are sent to the foul water stripper.

A holding tank for all MIS oil is provided. This tank acts as a surge during outage of above ground processing facilities, and allows a constant feed rate to the OUG facilities.

The off-gas processing system will consist of a single train of equipment.

Off-gas Compression. Off-gas compressors draw the MIS gas through the retorts and processing equipment and compress it for use at the CFBC.

The system consists of two equally sized parallel centrifugal compressors with individual suction knockout drums. For reliability, one compressor is steam driven, the other motor driven.

Incoming gas at 50°F is compressed from 6.75 psia to 27 psia and is delivered, without cooling, to the CFBC. Knockout condensate is pumped to the foul water surge tank in the foul water stripper unit. Antisurge recycle gas is returned for cooling to the direct contact condenser in the off-gas processing system.

The off-gas compression system maintains a slight vacuum at the top of the MIS retorts to permit the introduction of the required amount of air to each retort. The vacuum progressively increases toward the compressors.

During operation, capacity regulation is accomplished by base loading the motor-driven (constant speed) compressor and modulating the speed of the turbine-driven compressor to maintain constant pressure at the off-gas entrance to the direct contact condenser. Manual valves at the lower bulkheads of each retort are adjusted to balance capacity between the retorts. Control valves at the upper bulkhead of each active retort regulate the air volumes to each retort.

During outage of the turbine-driven compressor, the suction of the motor-driven machine is throttled to maintain the controlled pressure.

On shutdown of one or both compressors, the air to the active retorts is shut off. This action immediately reduces gas production from all retorts to about 60 percent of normal. When only one compressor is shut down, there should be sufficient compressor capacity to handle the evolved gas; especially if immediate action is taken to increase the set point for the controlled pressure at the suction side of the direct contact condenser and to open all lower bulkhead valves.

Should both compressors shut down, the auxiliary engine-driven vent fan is started. This fan is necessary because the gas evolved from the retorts, when air to the retorts is off, will produce a pressure drop in the retort gas line to the surface greater than the natural draft. The fan will exhaust to the vent stack.

Foul Water Stripping. The foul water stripping section receives sour process condensate from the off-gas processing section including the direct contact condenser. The combined water is treated for oil and sludge removal and ammonia is stripped so that the water can be recirculated to the contact condenser and used elsewhere in the plant. Any excess stripped water is used for retort quench and ash wetting.

The foul water stream contains dissolved ammonia, carbon dioxide, and light organics with lesser quantities of hydrogen sulfide, carbon monoxide, and other contaminants, and will contain less than 10 ppm of free oil. This stream is pumped from the foul water surge tank, heat exchanged with stripped water and fed to the top of the foul water stripper.

The overhead gas from the foul water stripper contains primarily NH_3 , CO_2 , light organics, and other contaminants. The gas is ultimately consumed in the CFBC, where the ammonia is converted to N_2 and H_2O and combustibles are burned.

The stripped foul water from the bottom of the tower contains less than 50 ppmw of free ammonia. It is cooled by heat exchange with the feed and by air cooling to 120°F, and is distributed for use as follows:

- As makeup absorption water to the upper section of the direct contact condenser after further cooling to 82°F
- Other plant uses as required

To minimize steam usage, provisions are made to send foul water to the retort water tank without stripping.

The tank off-gas blower compresses vent gases collected from tank vents for disposal in the boiler fire box along with the foul gas.

Mined Shale Handling and Processing

The mined shale processing systems prepare shale for the AGR and CFBC and are shown on Figures 7-8 and 7-9.

Oil shale is mined and crushed to a nominal 8-inch lump size before being hoisted to the surface and discharged into the production headframe storage bin. The shale is drawn from the bin with an apron feeder and conveyor which transfers the shale to a live stockpile to maintain a four-day supply of feed to the shale preparation plant.

Coarse shale is reclaimed by belt feeders discharging to two primary crushers. Belt scales on the crusher feed conveyors weight the shale and, by means of a feedback circuit, set the rate of the belt feeders. Four belt feeders are provided, each capable of handling up to 50 percent of the required rate. A dust collection system controls fugitive dust.

Primary crusher feed conveyors deliver the coarse shale to two single-stage roll crushers. An electromagnet, installed on the discharge end of each conveyor, captures any tramp iron in the shale.

The roll crushers discharge to secondary crusher feed conveyors which feed the secondary crusher's surge bin. The shale is recovered from this surge bin via bottom vibratory feeders which feed the secondary crushers. Here shale is crushed to the nominal -1/4" X 0" required by the HRS above ground retort.

The final prepared material is conveyed to the HRS above ground retort.

There is a 100 percent redundancy in all conveying and crushing equipment to assure the required stream factor for the boilers. The crushers are capable of much more feed than the normal conveyor carrying capacity to assure that they will not stall in the event of a sudden surge. The primary and secondary crusher buildings are insulated and heated to maintain a minimum temperature of 45°F.

Coal Handling System. The coal handling system is required only for Cases 1 and 2. The coal handling system for Case 1 is shown on Figure 7-10. In view of the small quantity of coal used, coal delivery to the plant site will be via trucks.

Trucks will discharge into a receiving hopper. The coal will be delivered from this hopper to a live storage site by belt conveyors. Coal will be reclaimed from this live storage site and delivered by belt conveyor to an intermediate storage hopper supplying the crushers.

The coal will be crushed to a nominal -1/4" X 0" size and delivered by belt conveyor to the boiler feed silo.

Feed to each conveyor system will be controlled with vibratory feeders. Magnetic separators to remove tramp iron will be installed at the head end of the conveyor feeding the 10-ton intermediate storage.

A dual 100 percent redundant conveying and crushing system will be used to assure continuous feed to the CFBC.

Dust collection, fire protection and ventilation requirements are provided. The crusher building will be heated and insulated to maintain a minimum temperature of 45°F. The maximum temperature will be controlled by ventilation only.

Steam/Power Generation Plant

Circulating Fluid Bed Combustors (CFBC) will be used to burn the various forms of fuels available from the shale oil process plants, including raw shale. They produce process steam and power for the process and mining operations. Excess power will be sold to local utilities.

Five such units of essentially the same size are utilized in Case 1 to consume all the fuels that are available. Cases 2 and 2A will each require one steam/power generation plant.

CFBC fuels in Case 1, 2 and 2A will consist of MIS gases, AGR spent shale, fuel gas and flue gas, and coal.

Circulating Fluid Bed Combustor. CFBC is a relatively new type of boiler and is used extensively for removal of SO_2 by adsorption using lime or limestone. Thus, the need for expensive flue gas scrubbers is eliminated. In this application, shale will be the source of the alkaline minerals comparable to limestone. Flow diagrams of the CFBC/Power Plant are presented in Figures 7-11 and 7-12.

The primary CFBC components are the combustion chamber, the hot cyclone collector, and the heat recovery section. Combustion and sulfur reactions take place in the combustion chamber which is usually of membrane waterwall welded panel construction. Fuel and other materials such as limestone or shale are fed into the lower combustion chamber. Primary air is blown through the fluidization grid plate to create a velocity sufficient to fluidize the bed. Dense fluidized system material is retained in the lower portion of the chamber, while the upper portion contains the entrained less-dense materials. This process gives the CFBC an excellent mixing characteristics. The less-dense system material is carried through the combustion chamber into the hot cyclone collector where most of the entrained material is separated from the hot gases. The former is reinjected into the combustion chamber through a nonmechanical seal. Hot flue gases leave the cyclone collector and enter a conventional boiler heat recovery section. From there the flue gas continues to a dust collection system, where the remaining entrained particles are removed to meet environmental requirements. The flue gas is then discharged to the stack via an induced-draft fan.

Combustion air is supplied by primary and secondary fans. The primary air is supplied below the fluidizing grid plate which forms the bottom of the combustion chamber. Secondary air is supplied at various levels in the lower portion of the combustion chamber for staged combustion. This staged combustion process and the low combustion temperatures practically eliminate thermal NO_x formation. Secondary air is also ducted to the startup burners. High-pressure air is provided by a rotary positive displacement blower. This air is used to fluidize solids in the nonmechanical seal and return them to the lower combustion chamber. The design of the steam and water circuits associated with the CFBC system is similar to that of conventional boilers. Feedwater is supplied to the economizer, where it is heated before delivery to the steam drum. From the drum, the water is delivered via downcomers and headers to the combustion chamber membrane walls where it receives additional heat from the fluidized

combustion reaction and is returned as a steam/water mixture to the steam drum. Depending on the type of fuel and steam conditions, a convective boiler bank section may also be required for the remaining evaporative duty not provided by the combustion chamber. All evaporative sections are arranged for natural circulation. Air preheater and superheater sections are included as required.

Solid fuels are typically conveyed to separate surge hoppers located adjacent to the boiler. From these surge hoppers, the fuels are fed to the boiler via appropriate feed systems and controls.

Bottom ash is removed from the lower part of the combustion chamber through a special nonmechanical device which classifies and cools the ash material. Fines are reinjected into the combustion chamber as required.

Since the combustion chamber temperature is well below the ash fusion point for most fuels, the need for waterwall soot blowers is eliminated. Due to the nature of the ash formed at these lower combustion temperatures, general soot blowing requirements are substantially less than in conventional boilers.

Each CFBC is capable of producing 380,000 lb/hr of steam at 1,300 psig and 955°F. This steam will be expanded in conventional turbines having extraction provisions for process steam requirements. The turbine is capable of accepting full steam flow when process steam is not required. The turbine will exhaust to a surface condenser at 3.5 inch of mercury back pressure.

One of the primary advantages of using a CFBC for power/steam production is that it makes possible utilization of the spent shale for sulfur adsorption. In-situ adsorption of sulfur using limestone as the source of calcium is a well established technology. And although the use of spent shale has not been demonstrated on a large scale, preliminary indications from pilot plant tests conducted by the EPA are that this method is also effective.

A critical determinant of effectiveness is the ratio of calcium in the spent shale to sulfur in the fuel streams. The normal range for a typical CFBC burning coal with limestone as the sulfur adsorbent is a 2:1 to 3:1 molar ratio of Ca to S. However, the EPA tests for shale were based on a molar ratio of 10:1. The calcium content of the spent shale from the HRS retort is as shown below:

calcite [CaCO ₃] content	9.2%

dolomite $[\text{CaMg}(\text{CO}_3)_2]$ content 7.0%

Incorporating these data, Table 7-4 shows the molar ratio of calcium to sulfur for Case 1. The calcium in the form of calcite is known to be useful for sulfur capture, but the calcium in dolomite may not be as useful. The magnesium in dolomite is not useful for sulfur capture. The table shows the ratio for calcium from calcite alone as well as for calcium from both calcite and dolomite. Even after taking credit for the calcium in dolomite, the Ca to S ratio is still only slightly over 2. Therefore, a very high reactivity rate is necessary for this quantity of shale to prove adequate. Ultimately, its effectiveness can only be established by testing. If testing proves that this ratio is inadequate, limestone will be required.

Table 7-5 shows the calcium to sulfur ratios for Case 2. As compared to Case 1, counteracting trends are evident. First, the scaled down MIS operation produces less off-gas requiring desulfurization, but it also produces less shale. While these two effects cancel each other, the increased quantity of coal requires more calcium. The net result is that limestone is required to maintain a sufficient calcium to sulfur ratio.

Case 2A is one-eleventh (1/11) of the size of Case 1 and the calcium to sulfur ratios would be proportionately the same as shown in Table 7-4, for Case 1.

The decision to use coal rather than raw shale for supplemental firing is based both on technical and economic factors. A major consideration is the effect on HRS oil production. Because any shale used as fuel would otherwise be fed to the HRS retort, using raw shale in the CFBC represents a significant loss of oil production capacity. In the commercial case, approximately 50 percent of the raw shale would have to be used as supplemental fuel. Furthermore, a reduced quantity of HRS fuel gas would be available to the CFBC. This would necessitate greater quantities of supplemental fuel to maintain flame stability.

At the same time, the MIS process is not affected by the choice of supplemental fuel. The low Btu MIS off-gas is the main reason supplemental firing is required. Therefore, the total heating value of fuel required for supplemental firing remains the same regardless of the type of fuel used because the MIS process is unaffected.

The heating value of raw shale is less than 25 percent that of coal. Therefore, even ignoring the loss of HRS fuel gas mentioned above, the amount of supplemental fuel required would be four

times as much using raw shale. Raw shale would have to be much cheaper than coal to make that option economically viable.

The CFBC material balances for Cases 1, 2, and 2A are presented in Tables 7-6, 7-7, and 7-8, respectively.

Above ground Retorting and Processing

The AGR plant performs the following operations:

- Retorting
- Retort effluent quenching
- Deashing
- Recycle gas separation
- Spent shale processing

The material balances for Cases 1, 2/2A, and 3, for the HRS above ground retort are presented in Tables 7-9, 7-10, and 7-11, respectively.

Hot-Recycled-Solids Retorting. Raw shale together with hot-recycled-solids pass by gravity and in plug flow through the Pyrolyzer. Oil vapor and gas liberated from the shale pass radially across the Pyrolyzer and are collected and removed at several points along the Pyrolyzer for downstream processing. The pyrolyzed shale is conveyed pneumatically through an Air Lift Combustor to a Classifier where the hot solids disengage from the flue gases. The hot solids fall from the Classifier through a Delayed Fall Combustor, then through a Fluidized Bed Combustor (FBC). At this point, essentially all combustibles have been burned from the shale. Removal of spent shale from the FBC is regulated to maintain the proper level in the FBC. The hot recycled solids from the FBC are combined with raw shale in a Fluid Bed Mixer before entering the Pyrolyzer. The rate of raw shale addition is varied to maintain the desired temperature in the Pyrolyzer.

Secondary air for the Circulating Fluidized Bed Combustor (CFBC) is used to convey spent shale pneumatically to the CFBC.

There is a single HRS retort in each of the cases in the study. Each retort is sized to process the design raw shale feed rate.

Case	1	2 & 2A	3
Feed Rate (tons/stream/day)	12,800	1,000	100

A diagram of the HRS retort is shown on Figure 7-13.

Retort Effluent Quenching. As shown on Figure 7-14, reactor effluent consisting of recycle gas and pyrolysis product flows to a high temperature quench tower where it is cooled by pump-around streams. The tower contains disk and doughnut trays to minimize holdup of solids contained in the feed. The overhead goes to a low temperature quench tower where it also is cooled by a pump-around stream. Again, disk and doughnut trays are used.

The degree of separation in these towers is admittedly low, however the heaviest fraction contained in the overhead from the low temperature quench tower will be a light naphtha which will separate readily from water condensed from the overhead. The separator following the overhead condenser will be provided with a baffle and level and interface controls so that sour water and naphtha are recovered separately.

Deashing. As shown on Figure 7-14, the bottom product streams from the two quench towers are cooled to 280°F. The naphtha stream is heated to 280°F. Process water in the amount of about 10 percent by weight of the total hydrocarbon is heated to 280°F under sufficient pressure to prevent boiling. These streams are all combined and passed through a mixing device to cause intimate contact between the oil and the water. Prior to mixing, an appropriate additive is added to the water to allow such vigorous mixing with minimum formation of a stable emulsion. The combined stream goes to a separator where dirty water (containing fine particles of shale carried over in the retort effluent) is separated from deashed oil. The separator drum will have provision for the intermittent removal of any emulsion at the oil-water interface.

The emulsion removal system treats any persistent emulsion from the deasher. Any emulsion formed is routed to the deasher emulsion tanks. The emulsion is mixed with an emulsion-breaking chemical and heated in the tanks. After phase separation, the oil phase is drawn off, cooled and returned to the deashing section. The water phase, containing some shale fines, is pumped to the spent shale cooling system.

Recycle Gas Separation. As shown on Figure 7-14, the gas stream from the low temperature quench separator drum goes through a knockout drum on its way to a compressor where it is compressed to 33.5 psia. The compressed gas is divided into a product gas stream and a recycle stream. The product gas is

used as plant fuel. The recycle gas is heated in a furnace to 1000°F on its way to the retort.

Spent Shale Processing. In Cases 1, 2, and 2A, the spent shale is carried pneumatically by secondary air from the spent shale lock hopper on the HRS retort to the CFBC. The spent shale ultimately becomes a part of the ash from the CFBC.

In Case 3, the spent shale is carried pneumatically to a baghouse. En route, the shale is cooled by means of water sprays in the transfer line (see Figure 7-15). The maximum allowable temperature to the baghouse is about 300°F. If additional cooling is required beyond that attained in the transfer line, a vortex type of mixer may be added between the line and the baghouse. In this case, a shale-water slurry would be produced in addition to dry shale from the baghouse. The flue gases from the retort are cooled in a similar manner on their way to the baghouse.

Oil Upgrading.

Before processing in most conventional refineries, raw shale oil must be fractionated and pretreated to remove excess nitrogen and arsenic and to lower the pour point of the oil.

Union Oil Company's proprietary upgrading technology is used in this study. The raw shale oil is subjected to severe hydrotreatment to remove arsenic, nitrogen, and sulfur. Process operations include hydrotreating, hydrogen production, and recovery of sulfur and anhydrous ammonia.

Fractionation. The primary purpose of the fractionation unit is to produce a shale oil suitable for storage and further processing.

Deashed oil is preheated to 400°F. The hot feed passes through a pressure control valve which maintains a back pressure on the upstream equipment sufficient to prevent flashing. The feed then enters the fractionation unit. The overhead vapors are partially condensed and cooled in the fractionator overhead condenser and collected in the reflux accumulator, where vapor liquid separation takes place. The condensed liquids include all of the water contained in the fractionator feed.

The water settles out in the accumulator boot and is pumped to the sour water treating unit. The net vapor stream from the reflux accumulator is compressed and fed to the debutanizer.

The fractionator reboil heat is provided by a pump-through reboiler. The reboiler heating medium is hot oil circulated from a fired

heater. The net bottoms from the fractionation unit are cooled in a heat exchange train which includes the fractionator feed/bottoms exchanger, the product oil/crude shale oil preheat exchanger (in the deashing area), and the shale oil product cooler and are then sent to the hydrotreating unit.

The net overhead liquid from the fractionator reflux accumulator is preheated to 300°F in the debutanizer feed/bottoms exchanger, and fed to the debutanizer. The debutanizer overhead vapors are cooled and condensed in the overhead condenser. The noncondensable vapor stream containing all the gases and a very small amount of C5+ material is sent to the fuel gas system. All of the overhead condensate is refluxed to the debutanizer. There is no net overhead hydrocarbon liquid produced. The small amount of water in the feed to the debutanizer is collected overhead, condensed, and settles out in the reflux accumulator. It is combined with the sour water from the fractionator reflux accumulator and sent to the sour water treating unit. The debutanizer bottoms are combined with the partially cooled, stabilized shale oil from the fractionator (bottoms), further cooled with the fractionator bottom stream and are sent to the hydrotreating unit.

Hydrotreating Unit. The hydrotreating unit accomplishes two important processing steps: dearsenizing/pretreating and hydrotreating. The dearsenizing/pretreating section treats deashed shale oil to remove arsenic, particulates and metals. This section also hydrogenates mono-olefins, diolefins, and other compounds in the oil which could cause catalyst bed fouling and catalyst deactivation in the downstream treating section. The dearsenizer/pretreater also converts some sulfur, nitrogen, and oxygen compounds in the oil to hydrogen sulfide, ammonia, and water. The hydrotreating/hydrocracking section reduces nitrogen and sulfur and improves viscosity and pour point of the shale oil.

Dearsenizing/Pretreater. Deashed shale oil is pumped from raw oil tankage to the pretreating feed drum. The oil feed from the surge drum mixes with cold recycle gas and the mixture is preheated by exchange with hot reactor effluent. The preheated recycle gas and oil then flow to the fired process heater and are heated to reaction temperature. The oil and gas mixture flows from the fired heater to a series of fixed bed reactors in which the oil is filtered, dearsenized, and mildly hydrotreated.

There are three parts to the reactor section of the dearsenizer/pretreater. The first consists of the guard reactors which are filled with inerts that have a high capacity for holding particulates while minimizing plugging. These guard reactors are

designed to prevent plugging in the downstream reactors by filtering out ash and particulates components that were not removed in the upstream deashing unit. The second part of the reactor section contains the dearsenizing reactors which are filled with an absorbent that removes arsenic from the oil. The last part of the reactor section contains the pretreating reactor designed to stabilize the oil and remove any compounds that would cause catalyst bed fouling of the hydrotreating/ hydrocracking section.

Effluent from the final reactor is cooled by exchange with the reactor charge and flows to a hot separator where it flashes to produce an overhead vapor and a bottoms liquid product. The liquid stream is routed directly to the hydrotreating feed surge drum. The overhead vapor from the hot separator is cooled and further flashed in the cold separator. The vapor from this separator is compressed and recycled back to the reactors. The liquid phase is combined with the liquid from the hot separator and is routed to the hydrotreating feed surge drum.

Hydrotreating/Hydrocracking. The hydrotreating/hydrocracking section processes shale oil that has been filtered, dearsenized, and mildly hydrotreated in an upstream dearsenizing/pretreating unit. The hydrotreating/hydrocracking section is designed to severely hydrotreat the oil to substantially reduce its nitrogen content and improve viscosity and pour point characteristics.

Dearsenized oil from the hot and cold separators of the dearsenizing/pretreating section flows into the hydrotreating feed surge drum. The shale oil feed from the surge drum is preheated by exchange with the product stabilizer bottoms and the hot reactor effluent. The heated feed is combined with heated hydrotreater recycle gas and injected into the first hydrotreating reactor. Cool recycle gas is injected into selected locations in the reactor beds to absorb the heat of reaction, thereby, holding bed temperatures to predetermined levels.

The effluent from the bottom of the first reactor is passed to the second and third reactors, respectively. Cold recycle gas is likewise injected into selected locations of the second and third reactor to absorb heat of reaction and limit temperature rise. Hot effluent from the third reactor is passed through the feed and recycle gas preheaters to cool and condense oil. The cooled product is phase separated. The vapor phase (unreacted hydrogen) is scrubbed, combined with makeup hydrogen, and recompressed for recycle. The liquid phase is flashed to remove volatile constituents and fed to the stabilizer reboiler. The resultant gases from flashing are washed to remove foul constituents and

sent to sour gas treating. The resultant foul water is sent to foul water treating.

The stabilizer is a distillation operation used to remove most of the light constituents from the treated oil, thereby, lowering the vapor pressure. Reboil heat is obtained from the third reactor effluent (part of the cooling train for the effluent). Reflux consists of condensate generated from the flash operations prior to feeding the stabilizer. The light overheads are combined with other sour gases and sent to sour gas treating. The bottom is cooled and constitutes the hydrotreated products.

Hydrogen Unit. The hydrogen unit uses natural gas as a feed stock to produce hydrogen for use in the hydrotreating unit.

Natural gas is compressed from 45 psig to 433 psig by the first- and second-stage compressor and heated to 700°F in a feed preheat exchanger. The gas is then passed through a cobalt-moly bed and a zinc oxide bed to remove trace amounts of hydrogen sulfide or mercaptans. Steam is added to the treated feed gas and the mixture is heated and partially reformed. The partially reformed gas is cooled in the waste heat boiler and reformed further in a high-temperature shift converter.

The reformed mixture is cooled in the boiler feedwater/product gas exchanger and the resulting two-phase mixture is separated in the first condensate knockout drum. The liquid, being relatively pure water, is sent to the stripping section of the deaerator. The vapor is cooled to 110°F in the product cooler, and the two-phase mixture is separated in the second condensate knockout drum. The liquid is stripped of carbon dioxide in the decarbonator, and also sent to the stripping section of the deaerator.

The vapor from the drum is sent to the pressure swing adsorbers (PSA) for purification into the hydrogen product. The hydrogen is filtered in the hydrogen product filter and is sent to the hydrotreating unit. The purge gas from the pressure swing adsorbers is used as fuel in the reformer furnace.

The steam system in the hydrogen unit is designed to handle the steam requirements of the entire OUG facilities. The system consists of a deaerator, high-pressure boiler feedwater pumps, reformer waste heat boiler feedwater pumps, and condensate pumps.

Sour Water and Sour Gas Treating Unit. The sour water treating unit removes ammonia and hydrogen sulfide. It produces anhydrous ammonia from sour water generated by the quenching

of hydrogen recycle gas in the hydrotreating unit, from that produced in the AGR unit, and from sour water from the OUG sulfur recovery unit. The combined sour water stream is steam stripped to remove hydrogen sulfide and ammonia. The stripped water is recycled to the hydrotreating unit quenching process. The sour gases from the sour water stripper overhead are then routed to a proprietary process, the Phosam-W process. In the Phosam-W process, the ammonia is removed from these sour gases by absorbing with a lean phosphoric acid solution. The ammonia-free sour gas is then routed to the OUG sulfur recovery unit for H₂S removal.

The rich phosphoric acid (ammonium phosphate) is heated; whereupon, the ammonium phosphate decomposes into ammonia and phosphoric acid. The regenerated phosphoric acid is recycled and the ammonia recovered as anhydrous ammonia for sale.

Syncrude Pipeline

The syncrude pipeline is a 46-mile pipeline to connect the plant site with an existing Chevron Oil crude oil network at Rangely, Colorado. One pump station, located at the plant site, is provided. The pipeline capacity is a nominal 700 GPM.

Utilities

Electrical System. The electrical systems provided for the power generation plant include:

- Main generator step-up transformer (13.8KV/345KV)
- Normal station service transformer (13.8 KV/4160V)
- Station auxiliary power transformers (345KV/4160V)
- 4160 switchgear
- 480V MCC

- Lighting
- Communication

These systems provide power to the plant for oil shale processes and for sale to the local utilities.

Plant Auxiliaries. Plant auxiliaries include auxiliary steam and boiler feedwater.

Auxiliary Steam. Auxiliary steam will be required for startup and for certain services while the CFBC is down for repairs or inspection. This auxiliary steam will be generated by a packaged oil fired boiler. The capacity will be 150,000 lb/hr at 350 psig.

Boiler Feedwater. Boiler feedwater treatment will consist of mixed resin bed demineralizers. A single 100 gpm train will be provided for each boiler. Each demineralizer will have its own chemical injection system.

UTILITY REQUIREMENTS

The utility requirements for Cases 1, 2/2A and 3 are shown in Tables 7-12, 7-13, and 7-14, respectively.

The CFBC will generate all power and steam requirements in Cases 1 and 2. Where there is excess power, it will be sold. Power for Case 3 is available from local utilities.

The power for the cooling water system and plant and instrument air supply is included in the utilities and offsite section.

Power requirements were derived by summing equipment brake horsepower quantities. The brake horsepower values were those calculated in sizing specific equipment.

An item of concern is the amount of raw water required for each of the cases. This large quantity is primarily for cooling tower makeup. The large cooling water load is caused by the high heat rejection in the steam turbine condensers. The quantity of cooling water required will be minimized by using air cooling to the extent possible. This will be determined in the design phase.

CATALYST AND CHEMICAL CONSUMPTION

The catalyst and chemical consumption for Cases 1, 2 and 2A are shown in Tables 7-15 and 7-16, respectively.

COMMERCIAL PLANT

[illegible]

Table 7-2
OVERALL MATERIAL BALANCE - CASE 2
DEMONSTRATION PLANT

[illegible]

Table 7-2 (Continued)

OVERALL MATERIAL BALANCE - CASE 2

DEMONSTRATION PLANT

[illegible]

Table 7-3
OVERALL MATERIAL BALANCE - CASE 3
PILOT PLANT

		ABOVEGROUND RETORTING FACILITIES - AREA 4600						
STREAM NO.		8	9	10	11	12	13	14
COMPONENT	MW	SHALE FEED	AGR OIL	COMB. AIR	FLUE GAS	FUEL GAS	SPENT SHALE	SOUR WATER
H2	2					3		
N2	28			3,319	3,319			
O2	32			882	219			
CO	28					10		
CO2	44				785	54		
CH4	16					17		
C2H4	28							
C2H6	30					13		
C3H6	42							
C3H8	44					29		
C4'S	57					45		
C5'S	71					10		
C6+	--					18		
NH3	17							
S	32							
H2S	34							
SO2	64							
CXHYSZ	--							
H2O	18				117	17		131
CaCO3	100							
CaO	56							
MgCO3	84							
MgO	40							
INERTS	--						6,946	
ORGANICS	--							
OIL	--		803					
COAL	--							
TOTAL PPH		8,333	803	4,201	4,440	216	6,946	131
AV MW								
BTU/SCF								
BTU/LB								
Gpm								3
BPCD			58					
API GRAV			27.3					
MMBTU/H								

Table 7-4

CALCIUM/SULFUR MOLAR RATIOS
CASE 1

STREAM		SULFUR CONTENT	Ca IN CaCO3 REQUIRED AVAILABLE TPSD	PLUS Ca IN DOLOMITE AVAILABLE	PLUS Mg IN DOLOMITE AVAILABLE
SPENT SHALE	8,123 TPSD 0 Btu/lb	21 TPSD	26.3	299	447
HRS FLUE GAS	6,855 TPSD 0 Btu/lb	0			
PLUS SHALE FINES	2,570 TPSD 0 Btu/lb	6.64 TPSD	8.3	95	142
HRS DIRTY WATER	127 TPSD 0 Btu/lb				
INCLUDES SHALE FINES	13 TPSD 0 Btu/lb	0.034 TPSD	0.04		
HRS FUEL GAS	265 TPSD 13,200 Btu/lb	negl.			
MIS SOUR GAS	1,776 TPSD 0 Btu/lb	4 TPSD	5.0		
MIS OFFGAS	24,187 TPSD 864 Btu/lb	204 TPSD H2S 192.0 TPSD Sulfur	240.0		
SUPPLEMENTAL COAL	1,044 TPSD 10,300 Btu/lb	0.5 % SULFUR 5.22 TPSD	6.5		
TOTAL			286.1	393.5	588.8
MOLAR RATIO				1.38	2.06
RAW SHALE REQU'D FOR MOLAR RATIO OF (ASSUMING DOLOMITE IS NOT EFFECTIVE)			2 3	WHICH IS WHICH IS	2,128 TPSD 5,534 TPSD

Table 7-5

CALCIUM/SULFUR MOLAR RATIOS
CASE 2

STREAM	QUANTITY	SULFUR CONTENT	Ca IN CaCO ₃ REQUIRED TPSD	CaCO ₃ AVAILABLE	PLUS Ca IN DOLOMITE AVAILABLE	PLUS Mg IN DOLOMITE AVAILABLE
SPENT SHALE	625 TPSD 0 Btu/lb	1.62 TPSD	2.0	23	34	41
HRS FLUE GAS	527 TPSD 0 Btu/lb	0.00				
PLUS SHALE FINES	198 TPSD 0 Btu/lb	0.04 TPSD	0.0	7	11	13
HRS DIRTY WATER	10 TPSD 0 Btu/lb					
INCLUDES SHALE FINES	1 TPSD 0 Btu/lb	0.00 TPSD	0.0			
HRS FUEL GAS	20 TPSD 13,200 Btu/lb	negl.				
MIS SOUR GAS	161 TPSD 0 Btu/lb	0.36 TPSD	0.5			
MIS OFFGAS	2,199 TPSD 864 Btu/lb	18.55 TPSD H ₂ S 17.45 TPSD Sulfur	21.8			
SUPPLEMENTAL COAL	2,640 TPSD 10,300 Btu/lb	0.50 % sulfur 13.20 TPSD	16.5			
TOTAL			40.8	30.3	45.3	54.3
MOLAR RATIO				0.74	1.11	1.33
LIMESTONE REQUIRED FOR MOLAR RATIO OF: (ASSUMING DOLOMITE IS NOT EFFECTIVE)			2.0 2.5 3.0	WHICH IS WHICH IS WHICH IS	162 TPSD = 227 TPSD = 291 TPSD =	6.8 TPH 9.5 TPH 12.1 TPH

Table 7-6

CFBC

MATERIAL/UTILITY BALANCE
Case 1

ITEM	TOTAL		PER BOILER	
Material Streams				
Feeds				
MIS Offgas	2,015,559	pph	403,112	pph
MIS Sour Gas	148,027	pph	29,605	pph
HRS Fuel Gas	22,087	pph	4,417	pph
HRS Flue Gas (w/ fines)	571,225	pph	114,245	pph
HRS Dirty Water	10,583	pph	2,117	pph
Spent Shale	338	tph	68	tph
Shale Fines	107	tph	21	tph
Coal	44	tph	9	tph
Ash				
Fly Ash	110-320	tph	20-65	tph
Bottom Ash	110-320	tph	20-65	tph
Total Ash	431	tph	86	tph
Steam Cycle				
Steam Produced	1,878,100	pph	375,620	pph
HP Extraction				
Process	555,000	pph		
FW Heating	260,000	pph		
LP Extraction				
Process	99,000	pph		
FW Heating	260,000	pph		
Turbine Exhaust	704,100	pph		
a	990	Btu/lb		
Circ Water [1]	76,500	gpm		
	571	MMBtu/hr		
Power Production				
Gross Heat Rate	14,128	Btu/kw0.hr		
Total	135	MW		
Power to CFBC Plant	21	MW		
Net Production	114	MW		
Miscellaneous				
Instrument Air	800	cfm		
a	100	psig		
Demineralized				
Makeup Water	50	gpm		

NOTES

[1] These circ water requirements are based on condensing main turbine exhaust only. Process steam is assumed to be returned to the CFBC plant as condensate.

Table 7-7

CFBC

MATERIAL/ UTILITY BALANCE
CASE 2

ITEM	QUANTITY	
Material Streams		
Feeds		
MIS Offgas	183,182	pph
MIS Sour Gas	13,457	pph
HRS Fuel Gas	1,699	pph
HRS Flue Gas (w/ fines)	43,940	pph
HRS Dirty Water	814	pph
Spent Shale	26	tph
Shale Fines	8.2	tph
Coal	21	tph
Limestone	5.1	tph
Ash		
Fly Ash	11-34	tph
Bottom Ash	11-34	tph
Total Ash	45	tph
Steam Cycle		
Steam Produced	375,620	pph
HP Extraction		
Process	46,000	pph
FW Heating	52,000	pph
LP Extraction		
Process	11,000	pph
FW Heating	52,000	pph
Turbine Exhaust	214,620	pph
	990	Btu/lb
Circ Water [1]	23,500	gpm
	174	MMBtu/hr
Power Production		
Gross Heat Rate	14,716	Btu/kw0.hr
Total	35.3	MW
Power to CFBC Plant	4.2	MW
Net Production	31.1	MW
Miscellaneous		
Instrument Air	200	cfm
	100	psig
Demineralized		
Makeup Water	10	gpm

NOTES

[1] These circ water requirements are based on condensing main turbine exhaust only. Process steam is assumed to be returned to the CFBC plant as condensate.

Table 7-8

CFBC

MATERIAL/ UTILITY BALANCE
CASE 2A

ITEM	QUANTITY	
Material Streams		
Feeds		
MIS Offgas	183,182	pph
MIS Sour Gas	13,457	pph
HRS Fuel Gas	1,699	pph
HRS Flue Gas (w/ fines)	43,940	pph
HRS Dirty Water	814	pph
Spent Shale	26	tph
Shale Fines	8.2	tph
Coal	4.2	tph
Ash		
Fly Ash	11-33	tph
Bottom Ash	11-33	tph
Total Ash	44	tph
Steam Cycle		
Steam Produced	166,260	pph
HP Extraction		
Process	46,000	pph
FW Heating	23,000	pph
LP Extraction		
Process	11,000	pph
FW Heating	23,000	pph
Turbine Exhaust	63,260	pph
	990	Btu/lb
		a
Circ Water [1]	7,000	gpm
	51	MMBtu/hr
Power Production		
Gross Heat Rate	14,124	Btu/kw0.hr
Total	12.0	MW
Power to CFBC Plant	2.0	MW
Net Production	10.0	MW
Miscellaneous		
Instrument Air	200	cfm
	100	psig
		a
Demineralized		
Makeup Water	4	gpm

NOTES

[1] These circ water requirements are based on condensing main turbine exhaust only. Process steam is assumed to be returned to the CFBC plant as condensate.

Table 7-9

HRS ABOVE GROUND RETORT FACILITIES

MATERIAL BALANCE - CASE 1

COMMERCIAL PLANT

	TPSD	M LB/SHr
INPUT:		
RAW SHALE	12,850	1,071
RECYCLE SHALE	38,551	3,213
RECYCLE GAS	822	69
COMBUSTION AIR	6,478	540
	-----	-----
TOTAL	58,701	4,892
OUTPUT:		
PRODUCT OIL	1,238	103
PRODUCT FUEL GAS	332	28
DIRTY WATER	132	11
SHALE FINES IN DIRTY WATER	11	1
NET SOUR WATER	70	6
FLUE GAS	6,846	571
SHALE IN FLUE GAS	2,570	214
RECYCLE GAS	822	69
RECYCLE SHALE	38,551	3,213
SPENT SHALE	8,129	677
	-----	-----
TOTAL	58,701	4,892

Table 7-10

HRS ABOVE GROUND RETORT FACILITIES

MATERIAL BALANCE - CASES 2 & 2A

DEMONSTRATION PLANT

	TPSD	LB/SHr
INPUT:		
RAW SHALE	1,000	83,333
RECYCLE SHALE	3,000	250,000
RECYCLE GAS	64	5,331
COMBUSTION AIR	504	42,010
	-----	-----
TOTAL	4,568	380,674
OUTPUT:		
PRODUCT OIL	96	8,028
PRODUCT FUEL GAS	26	2,153
DIRTY WATER	10	856
SHALE FINES IN DIRTY WATER	1	71
NET SOUR WATER	5	454
FLUE GAS	533	44,397
SHALE IN FLUE GAS	200	16,667
RECYCLE GAS	64	5,331
RECYCLE SHALE	3,000	250,000
SPENT SHALE	633	52,717
	-----	-----
TOTAL	4,568	380,674

Table 7-11

HRS ABOVE GROUND RETORT FACILITIES

MATERIAL BALANCE - CASE 3

PILOT PLANT

	TPSD	LB/SHr
INPUT:		
RAW SHALE	100	8,333
RECYCLE SHALE	300	25,000
RECYCLE GAS	6	533
COMBUSTION AIR	50	4,201
	----	-----
TOTAL	457	38,067
OUTPUT:		
PRODUCT OIL	10	803
PRODUCT FUEL GAS	3	215
DIRTY WATER	1	86
SHALE FINES IN DIRTY WATER	<1	7
NET SOUR WATER	1	45
FLUE GAS	53	4,440
SHALE IN FLUE GAS	20	1,667
RECYCLE GAS	6	533
RECYCLE SHALE	300	25,000
SPENT SHALE	63	5,272
	----	-----
TOTAL	457	38,067

Table 7-12

UTILITY REQUIREMENTS
CASE 1 - COMMERCIAL SIZE PLANT

AREA		MINING	6000 MIS PROCESS FACILITIES	7000 STEAM/POWER PLANT (CFBC)	4710 SHALE PREP. AREA	4600 ABOVE GROUND RETORTING	5000 OIL UPGRADING	UTILITIES/ OFFSITES	TOTALS STREAM DAY BASIS	TOTALS CALENDAR DAY BASIS
STREAM FACTOR		1.00	0.95	1.00	0.95	0.95	0.92	0.95		
ELECTRICAL POWER (KW)		13,000	34,268	(114,000)	1,620	15,200	10,800	4,050	(35,062)	(38,683)
STEAM (M LB/HR)	1500 PSIG									0
	600 PSIG		450	(555)			33	103	31	0
	150 PSIG		211	(99)			(4)	(103)	5	(0)
	50 PSIG						(72)		(72)	(66)
	BFW			25			195		220	204
	CLEAN CONDENSATE		(661)	654			186		179	197
	BD			(25)					(25)	(25)
WATER (M LB/HR)	RAW WATER	(925)	(460)		15	22		2,395	1,047	948
	WASTE WATER								0	0
COOLING (MM BTU/HR)	AIR		783						783	744
	WATER		702			93	36		831	789
COOLING WATER	(GPM)		84,500	76,500	10	9,268	2,900	50	173,228	168,305
FUEL (MM BTU/HR)	NG/FG	15		292 **		61 *	671	10	757	700
	SHALE			---					0	0
	MIS GAS			1,746					0	0
	COAL			896					896	896
AIR (SCFM)	PLANT/INSTR.	400	850	800	100	300	800		3,250	3,124

( ) INDICATES NET PRODUCTION OF UTILITY

* NET FUEL NG/FG REQUIRED: RETORT PRODUCT = 27,633 LB/HR LESS FUEL GAS TO CFBC = 22,087 LB/HR IS 5,546 LB/HR. (114 MMBTU/HR HEAT RELEASED/0.85)-(365 RETORT PRODUCT - 292 FG TO CFBC)=61 MM BTU/HR THIS CALCULATION TAKES CREDIT FOR THE BTU CONTENT OF THE FUEL GAS NOT FED TO THE CFBC.

** FUEL GAS PRODUCED BY ABOVE GROUND RETORT

Table 7-13

UTILITY REQUIREMENTS
CASE 2/2A - DEMONSTRATION SIZE PLANT

AREA		MINING	6000 MIS PROCESS FACILITIES	7000 STEAM/POWER PLANT (CFBC)	4710 SHALE PREP. AREA	4600 ABOVE GROUND RETORTING	UTILITIES/ OFFSITES	TOTALS STREAM DAY BASIS	TOTALS CALENDAR DAY BASIS
STREAM FACTOR		1.00	0.95	1.00	0.95	0.95	0.95		
ELECTRICAL POWER (KW)		1,353	3,115	(31,100/10,200)	127	1,183	315	(25,007/4,107)	(25,244/4,344)
STEAM (M LB/HR)	1500 PSIG								0
	600 PSIG		41	(46)			8	3	0
	150 PSIG		19	(11)			(8)	0	(0)
	50 PSIG							0	0
	BFW			5/2				5/2	5/2
	CLEAN CONDENSATE		(60)	60				0	3
	BD			(5/2)				(5/2)	(5/2)
WATER (M LB/HR)	RAW WATER	(100)	(38)		1.5	2	186	52	45
	WASTE WATER							0	0
COOLING (MM BTU/HR)	AIR		71					71	68
	WATER		64			7.2		71	67
COOLING WATER	(GPM)		7,700	23,500/7,000		721	4	31,925/15,425	31,504/15,004
FUEL (MM BTU/HR)	NG/FG	1.5		23 **		5 *	1	7	7
	SHALE			---				0	0
	MIS GAS			159				0	0
	COAL			433/81.5				433/81.5	433/81.5
AIR (SCFM)	PLANT/INSTRUMENT	150	250	200	10	21		631	617

( ) INDICATED NET PRODUCTION OF UTILITY

* NET FUEL NG/FG REQUIRED: RETORT PRODUCT = 2,150 LB/HR LESS FUEL GAS TO CFBC = 1,718 LB/HR
IS 431 LB/HR. (9 MMBTU/HR HEAT RELEASED/0.85)-(28.4 RETORT PRODUCT - 22.7 FG TO CFBC)=4.9 MM BTU/HR
THIS CALCULATION TAKES CREDIT FOR THE BTU CONTENT OF THE FUEL GAS NOT FED TO THE CFBC.

** FUEL GAS PRODUCED BY ABOVE GROUND RETORT

Table 7-14

UTILITY REQUIREMENTS
CASE 3 - PILOT SIZE PLANT

AREA		4600 ABOVE GROUND RETORTING	UTILITIES/ OFFSITES	TOTALS STREAM DAY BASIS	TOTALS CALENDAR DAY BASIS
STREAM FACTOR		0.95	0.95		
ELECTRICAL POWER	(KW)	148	32	180	171
STEAM	(M LB/HR)				
	1500 PSIG				
	600 PSIG		0	0	0
	150 PSIG		0	0	0
	50 PSIG				
	BFW				
	CLEAN CONDENSATE				
	BD				
WATER	(M LB/HR)				
	RAW WATER	1	19	20	19
	WASTE WATER				
COOLING	(MM BTU/HR)				
	AIR				
	WATER	1			
COOLING WATER	(GPM)	72	0	72	68
FUEL	(MM BTU/HR)				
	NG/FC	1 *	Neg.	1	1
	SHALE				
	MIS GAS				
	COAL				
AIR	(SCFM)				
	PLANT/INSTRUMENT	2		2	2

( ) INDICATED NET PRODUCTION OF UTILITY

* HEAT ABSORBED IN PROCESS HEATERS

Neg. = Negligible, i.e., less than 0.1 MMBtu/Hr.

Table 7-15

CATALYST AND CHEMICAL CONSUMPTION
CASE 1 - COMMERCIAL SIZE PLANT

		CONSUMPTION		
		UNITS	INITIAL CHARGE	ANNUAL USE
		-----	-----	-----
MIS SURFACE FACILITIES				
AREA 6010	UNDERGROUND RETORT SYSTEM DEMULSIFIER, TRETOLITE RP729	GAL		31,900
AREA 6020	OFFGAS PROCESSING ANHYDROUS AMMONIA	LBS	220,000	27,500
ABOVE GROUND RETORT				
AREA 4615	FRACTIONATION TRETOLITE 96% SULFURIC ACID DEMULSIFIER	LBS LBS GAL	39,585 59,378	158,340 158,200 588
OIL UPGRADING				
AREA 5010	HYDROGEN PLANT REFORMER CATALYST HT SHIFT CATALYST ZINC OXIDE COBALT MOLY CATALYST PSA ADSORBENT HYDRAZINE AMINE CAUSTIC	FT^3 FT^3 FT^3 FT^3 FT^3 GAL GAL GAL	825 924 825 289 26,175 41 41 41	413 309 550 97 NIL NIL NIL NIL
AREA 5020	HYDROTREATING UNIT ALUMINA BALLS DEARSENITING CATALYST PRETREAT CATALYST HYDROTREATING CATALYST HT CATALYST, NON-NOBLE DI-METHYL SULFIDE NITROGEN		PROPRIETARY V	 V 92,400 924

Table 7-16

CATALYST AND CHEMICAL CONSUMPTION
CASES 2 and 2A - DEMONSTRATION SIZE PLANT

			CONSUMPTION	
			INITIAL	ANNUAL
UNITS			CHARGE	USE
-----			-----	-----
MIS SURFACE FACILITIES				
AREA 6010	UNDERGROUND RETORT SYSTEM			
	DEMULSIFIER, TRETOLITE RP729	GAL		2,900
AREA 6020	OFFGAS PROCESSING			
	ANHYDROUS AMMONIA	LBS	20,000	2,500

Figure 7-1

LOCATION OF C-b TRACT

1 2 3 4 5 6 SCALE

Figure 7-2

LOCATION C-b TRACT

Figure 7-3
MIS MINE ISOMETRIC

Figure 7-4

OVERALL PLOT PLAN

Figure 7-5
BLOCK FLOW DIAGRAM
COMMERCIAL SIZE PLANT
CASE 1

Figure 7-6
BLOCK FLOW DIAGRAM
DEMONSTRATION SIZE PLANT
CASES 2, 2A

Figure 7-7

**BLOCK FLOW DIAGRAM
PILOT SCALE PLANT
CASE 3**

UTILITIES AND OFFSITE FACILITIES

UTILITIES

3710	Mine Water System
3740	Cooling Water System
3750	Inert Gas Generation System
3760	Instrument & Plant Air System
3770	Fuel Gas System
3780	Potable Water System
3781	Fire Water System
3782	Service Water System
3783	Oily/Storm Water System
3784	Sanitary Sewer System

OFFSITE FACILITIES

4000	Power Distribution
4100	Interconnecting Pipeways
4200	Buildings
4300	Site Preparation & Development
4400	Mobile Equipment
4530	Tank Farm
4540	Rifle Marshalling Yard
4550	Emergency Flare System
4900	Control System

Figure 7-8
SHALE PROCESSING PLANT

Figure 7-9

Figure 7-10

COAL HANDLING PLANT CASES 1 & 2

CFBC/POWER PLANT COMBUSTION-SIDE SCHEMATIC

Figure 7-12

CFBC/POWER PLANT
STEAM-SIDE SCHEMATIC

Figure 7-13

HRS RETORT ASSEMBLY

Figure 7-14
HRS RETORT GAS PROCESSING
FLOW DIAGRAM

Figure 7-15
MRS SPENT SHALE
PNEUMATIC TRANSPORT AND COOLING SYSTEM - CASE 3

TECHNICAL FEASIBILITY

This section discusses the technical feasibility of the various process areas.

MODIFIED-IN-SITU RETORT

Modified-In-Situ (MIS) technology has been developed and demonstrated by Occidental Oil Shale, Inc. at its Logan Wash site. Field testing at this site began in 1972 and the first experimental retort was ignited in 1973. A total of 11 experimental retorts have been in operation, including two units which were of commercial size. MIS retorting has been demonstrated at other locations. The Demonstration size facility will perfect the MIS system in this specific geological area and integrate the MIS below ground system with the above ground facilities. Improvements for conserving energy in rubblization, obtaining higher oil recovery and reducing mining costs will be forthcoming with more site-specific experience.

MODIFIED-IN-SITU OFF-GAS PROCESSING

Processing the MIS off-gas utilizes conventional refinery type hydrocarbon processing technologies of water scrubbing, sponge oil absorption, gas compression, and foul water stripping. These technologies have been used extensively in petroleum refining throughout the world.

ABOVE GROUND RETORTING

The Above Ground Retort employs an innovative concept developed by Lawrence Livermore National Laboratory (LLNL) which uses a recirculating hot-solid heat carrier in a continuous loop system.

The principle scale-up concern is the maintenance of uniform temperature and composition gradients through the retort in order to verify the laboratory results. For example, the laboratory size retort (in which this concept has been studied by LLNL) is four inches in diameter and the Pilot plant retort is 42 inches in diameter. This represents a scale up on flow area basis of more than 100 to 1.

Similarly, the proper functioning of the air lift combustor, the classifier, the delayed fall combustor, the fluidized bed combustor

and the fluidized bed mixer needs to be verified for this magnitude of scale-up.

CIRCULATING FLUIDIZED BED Combustor (CFBC)

CFBC technology has been demonstrated on a commercial scale, but not with the particular combination of fuels envisioned in this study. These fuels consist of HRS spent shale, HRS fuel gas, HRS flue gas, MIS sour gas, MIS off-gas and coal. Field tests, studies and laboratory evaluations have been conducted on oil shale combustion. A reasonable level of confidence has been reached that the shale will burn satisfactorily in a CFBC. It has also been shown that alkaline materials in the shale will act as an efficient SO₂ adsorbent which will result in the flue gas meeting environmental requirements.

The environment under which the CFBC must perform with the various fuel mixes is unique. Areas deemed necessary for exploration are:

- Boundaries of fuel mixes which will sustain stable combustion. The fuel mix off-gas, raw shale and spent shale is probably the most critical.
- The effect of these low-heating value and high-bulk fuels on the costs and economic viability of the CFBC.
- Equipment life expectancy when using these high-bulk, low-heating value fuels.
- The economic effect of the additional raw shale mining which may be required to supply supplemental fuel for the CFBC.
- Sulfur removal efficiency. The variability of sulfur in the various fuels will need to be established in order that proper estimation of sulfur emissions can be made.

Prior to the final process design, areas of optimization will be identified for each significant design variable. Proper allowances will be made during the detailed equipment design.

OIL UPGRADING FACILITY

The oil upgrading plant consists of standard petroleum refining units including a hydrotreater, a hydrogen plant, a sulfur recovery plant and an ammonia recovery unit, all of which pose little risk. The hydrotreater poses a certain element of risk since it requires somewhat severe operating conditions. The ammonia recovery

unit will operate with a feed different from normal. This feed change is not considered a high risk.

Both the MIS and HRS processes generally produce a lighter oil with a lower N_2 content than typical shale oils. This may reduce the upgrading costs.

Union's Parachute Creek facility has processed 1.5 million barrels of oil shale into a premium syncrude product. Oil shale has been successfully refined in oil shale operations in Sweden, Scotland, Australia, West Germany, the USSR and other countries. These have generally been on a relatively small scale and under special economic conditions.

APPENDIX

[REDACTED]

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CONSULTING GEOTECHNICAL AND MINING ENGINEERS
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GRAND JUNCTION, COLORADO 81506

139-1

June 9, 1989

Dr. Ray Zahradnik
Occidental Oil Shale, Inc.
1250 South Lincoln Avenue, Suite I-5
P. O. Box 880408
Steamboat Plaza
Steamboat Springs, CO 80488

Re: Occidental C-b; 14 Retort Demonstration Project, Mining Costs

Dear Ray:

This letter summarizes our preliminary estimate of costs to mine the access drifts and upper void, intermediate void, lower void, and production levels from the existing C-b service and production shafts. Our costs include personnel, equipment and supplies to:

- excavate shops and developments on each level;
- excavate upper void, intermediate void, lower void, and production levels for 14 retorts;
- excavate one ore pass connection for the upper and intermediate levels to the lower level;
- jaw crusher and associated loading facilities at the lower level;
- a shaft bottom cleanup system;
- ventilation system including surface fans and underground auxiliary distribution system; and
- pumping costs to lift mine water to the surface.

The estimates do not include the cost to rubbilize the material in the retorts, nor the cost to equip and operate the retorts and hoist the oil shale to the surface. Also, not included are the costs to excavate and line a shaft for the retort offgases. We have assumed that the product offgases will require a dedicated lined shaft with finished diameter of six feet. The cost of this shaft with liner could be as much as $\$6.9 \times 10^6$ if excavated by blind hole drilling (as was the USBM Horse Draw Shaft) or substantially lower if raise bore techniques can be used. It may be possible to install the production offgas pipe in the production shaft, but more engineering would be required before a cost estimate of that alternative could be presented.

Dr. Ray Zahradnik
June 9, 1989
Page 2

The mining cost estimate is based on using the existing equipment available at the site and appropriate new equipment where necessary. Table 1 lists the equipment and estimated capital costs.

Personnel costs are based on Unocal's current labor rates with a 1.4 multiplier to cover fringe benefits, FICA, worker compensation, vacation, sick leave, etc. We have assumed operations on a four day, two shifts per day, ten hours per shift basis. Personnel lists and rates are shown in Table 2. We have not included costs for inflation.

The equipment and crew are capable of mining oil shale at a slightly higher rate than required to develop 2-1/2 retorts per year. The project was planned to optimize production rate and assumes minimal interference from other retort activities. The peak rock production is 61,800 tons per month or 3,600 tons per working day. Figure 1 shows the production rate per quarter. At the rate shown, all 14 retorts could be developed in 57 months. Mining of the first retort void level would begin in Month 7. The first two retorts would be ready for rubbilization in Month 16. The total production is 2,414,200 tons.

Based on the above schedule, the steady state mining production costs averaged between the 3rd and 14th quarters were \$9.97 per ton of mined rock. The production costs include labor, supplies, maintenance, equipment operations, installation of crusher, lifting mine water to surface and ventilation (including shaft heating in winter), but not capital costs or depreciation. Table 3 summarizes these operating costs and also lists total costs that include capital amortized over the 57 months. Figure 2 shows the production cost per quarter, Figure 3 the production cost per ton per quarter, and Figure 4 the cumulative production cost per ton.

There are two options for presentation of this cost estimate you might consider. The first is to amortize the capital costs over the mine production. The capital costs (excluding the offgas shaft) is estimated to be \$4,200,000 or approximately \$1.74 per ton. This would bring the overall cost per ton to \$13.23 per ton (total operating cost plus capital/total tons produced).

The second alternative is to extend the mining schedule by nine months using the same equipment and crew. This would be consistent with the 2.5 retorts per year schedule used in the previous studies, and may occur because of unforeseen delays caused by coordination problems with the other underground operations of rubbilization, retort preparation, and retort operation. We have considered the impact on costs of extending the mining schedule by three quarters. Additional costs would include labor, pumping and ventilation (including heating in the winter), and would add \$1.12 to the overall cost, or \$14.35 per ton of mined oil shale.

We intend to address steady state costs of the commercial size operation when Roger Moore returns from Britain. We will be following this up with more complete data next week. If you have any questions or need more backup, please call.

Yours sincerely,

C. E. Brechtel
Senior Associate

MPH/kg

TABLE 1 CAPITAL EXPENDITURES

DESCRIPTION	PERMISSABLE	COST
	Y N E O S	(DOLLARS)
MODIFY EXISTING JUMBO	Y	100000
"COPPER RANGE" JUMBO	Y	550000
BENCH DRILL	N	325000
JACKLEGS	N/A	10000
SHOTCRETE PLANT	N/A	60000
EIMCO 918LHD	Y	N/A
EIMCO 918LHD	Y	N/A
EIMCO 913 LHD	Y	145000
EIMCO 913 LHD	Y	145000
EIMCO 985-T15 DUMP TRUCK	N	125000
EIMCO 985-T15 DUMP TRUCK	N	125000
EIMCO 985-T15 DUMP TRUCK	N	125000
SCALER	Y	290000
POWDER TRUCK	Y	120000
UTILITY LIFT TRUCK	Y	100000
ELEVATING PLATFORM TRK	Y	120000
MECHANICS TRUCK	N	70000
TRACTOR WATER	N	14000
TRACTOR VENT CREW	N	14000
TRACTOR MECHANICS	N	14000
TRACTOR UTILITY	N	14000
TANKER FUEL	N/A	10000
TANKER FUEL	N/A	10000
TANKER FUEL	N/A	10000
TANKER FUEL	N/A	10000
TANKER WATER	N/A	10000
TANKER WATER	N/A	10000
MATERIAL TRAILER	N/A	8000
MATERIAL TRAILER	N/A	8000
MATERIAL TRAILER	N/A	8000
POWDER TRAILER	N/A	15000
POWDER TRAILER	N/A	15000
MINE FAN	N	144000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
AUX FANS	Y	35000
COMPRESSORS		150000
SHOP TOOLS		200000
SHAFT CLEAN-OUT		80000
HYDRAULIC ROCK BREAKER		45000
CRUSHER		465000
CONVEYOR		150000
TOTAL		4129000

TABLE 2 ESTIMATED CB MINING OPERATIONS LABOR COSTS

JOB TITLE	WAGE
MINE MANAGER	60000
MINE ENGINEER	40000
ENGINEER TECH	25000
SECRETARY	12000
MAINT SUPT	35000
MINE SUPT	40000
SHIFT FOREMAN	35000
SHIFT FOREMAN	35000 2ND SHIFT
MAINT FORMAN	35000
MAINT FORMAN	35000 2ND SHIFT
10 TOTAL SALARY	
4 JUMBO OP	16.60
4 HELPER	13.00
1 BENCH DRILLER	13.00
1 HELPER	9.50
4 POWDERMAN	13.00
4 HELPER	9.50
6 LHD OPER	16.60
4 TRUCK DRIVER	13.00
2 SCALER OPER	16.60
2 BULL GANG LEAD	13.00
6 BULL GANG	9.50
2 TOP LANDER	9.50
2 TOP LANDER OP	13.00
2 CRUSHER OP	16.60
2 HELPER	9.50
2 SKIP TENDER	9.50
2 MECHANIC I	16.60
4 MECHANIC II	13.00
4 MECHANIC III	9.50
2 OILER	9.50
2 ELECTRICIAN	16.60
2 HELPER	13.00
64 TOTAL HOURLY	

TABLE 3 MINE PRODUCTION AND COST SUMMARY FOR 14 RETORT DEMONSTRATION PROJECT

QTR	TIME PERIOD	TONS MINED	CUM TONS MINED	MINE OPER COSTS	CUM MINE OPER COSTS	QTRLY OPER COST PER TON	TOTAL MINE COSTS	CUM TOTAL MINE COSTS	QTRLY TOTAL COST PER TON
1	YR 1 1ST QTR	0	0	553	553	50.00	5710.883	5710.883	50.00
2	YR 1 2ND QTR	82532	82532	553	1106	50.00	5710.883	11421.766	50.00
3	YR 1 3RD QTR	82532	165064	553	1659	50.00	5710.883	17132.649	50.00
4	YR 1 4TH QTR	82532	247596	553	2212	50.00	5710.883	22843.532	50.00
1	YR 2 1ST QTR	82532	330128	553	2765	50.00	5710.883	28554.415	50.00
2	YR 2 2ND QTR	82532	412660	553	3318	50.00	5710.883	34265.298	50.00
3	YR 2 3RD QTR	82532	495192	553	3871	50.00	5710.883	40000.181	50.00
4	YR 2 4TH QTR	82532	577724	553	4424	50.00	5710.883	45735.064	50.00
1	YR 3 1ST QTR	82532	660256	553	4977	50.00	5710.883	51469.947	50.00
2	YR 3 2ND QTR	82532	742788	553	5530	50.00	5710.883	57204.830	50.00
3	YR 3 3RD QTR	82532	825320	553	6083	50.00	5710.883	62939.713	50.00
4	YR 3 4TH QTR	82532	907852	553	6636	50.00	5710.883	68674.596	50.00
1	YR 4 1ST QTR	82532	990384	553	7189	50.00	5710.883	74409.479	50.00
2	YR 4 2ND QTR	82532	1072916	553	7742	50.00	5710.883	80144.362	50.00
3	YR 4 3RD QTR	82532	1155448	553	8295	50.00	5710.883	85879.245	50.00
4	YR 4 4TH QTR	82532	1237980	553	8848	50.00	5710.883	91614.128	50.00
1	YR 5 1ST QTR	82532	1320512	553	9401	50.00	5710.883	97349.011	50.00
2	YR 5 2ND QTR	82532	1403044	553	9954	50.00	5710.883	103083.894	50.00
3	YR 5 3RD QTR	82532	1485576	553	10507	50.00	5710.883	108818.777	50.00
4	YR 5 4TH QTR	82532	1568108	553	11060	50.00	5710.883	114553.660	50.00
1	YR 6 1ST QTR	82532	1650640	553	11613	50.00	5710.883	120288.543	50.00
2	YR 6 2ND QTR	82532	1733172	553	12166	50.00	5710.883	126023.426	50.00
3	YR 6 3RD QTR	82532	1815704	553	12719	50.00	5710.883	131758.309	50.00
4	YR 6 4TH QTR	82532	1898236	553	13272	50.00	5710.883	137493.192	50.00
1	YR 7 1ST QTR	82532	1980768	553	13825	50.00	5710.883	143228.075	50.00
2	YR 7 2ND QTR	82532	2063300	553	14378	50.00	5710.883	148962.958	50.00
3	YR 7 3RD QTR	82532	2145832	553	14931	50.00	5710.883	154697.841	50.00
4	YR 7 4TH QTR	82532	2228364	553	15484	50.00	5710.883	160432.724	50.00
1	YR 8 1ST QTR	82532	2310896	553	16037	50.00	5710.883	166167.607	50.00
2	YR 8 2ND QTR	82532	2393428	553	16590	50.00	5710.883	171902.490	50.00
3	YR 8 3RD QTR	82532	2475960	553	17143	50.00	5710.883	177637.373	50.00
4	YR 8 4TH QTR	82532	2558492	553	17696	50.00	5710.883	183372.256	50.00
1	YR 9 1ST QTR	82532	2641024	553	18249	50.00	5710.883	189107.139	50.00
2	YR 9 2ND QTR	82532	2723556	553	18802	50.00	5710.883	194842.022	50.00
3	YR 9 3RD QTR	82532	2806088	553	19355	50.00	5710.883	200576.905	50.00
4	YR 9 4TH QTR	82532	2888620	553	19908	50.00	5710.883	206311.788	50.00
1	YR 10 1ST QTR	82532	2971152	553	20461	50.00	5710.883	212046.671	50.00
2	YR 10 2ND QTR	82532	3053684	553	21014	50.00	5710.883	217781.554	50.00
3	YR 10 3RD QTR	82532	3136216	553	21567	50.00	5710.883	223516.437	50.00
4	YR 10 4TH QTR	82532	3218748	553	22120	50.00	5710.883	229251.320	50.00

FIGURE 1 - QUARTERLY AND CUMULATIVE MINE PRODUCTION
14 RETORT DEMONSTRATION PROJECT

FIGURE 2 - OPERATING AND TOTAL PRODUCTION COST PER TON
14 RETORT DEMONSTRATION PROJECT

FIGURE 3 - QUARTERLY OPERATING AND TOTAL MINING COSTS
14 RETORT DEMONSTRATION PROJECT

FIGURE 4 - CUMULATIVE OPERATING AND TOTAL COST PER TON
14 RETORT DEMONSTRATION PROJECT

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July 6, 1989

Dr. Ray Zahradnik
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1250 South Lincoln Avenue, Suite I-5
P. O. Box 880408
Steamboat Plaza
Steamboat Springs, CO 80488

Re: Occidental C-b; 17 Retort Demonstration Project, Mining Costs

Dear Ray:

This letter summarizes our estimate of costs to mine access drifts and the upper, intermediate, lower and product levels for a 17 retort demonstration project from the existing C-b service and production shafts. This estimate is based upon the same assumptions used in our previous study of the 14 retort case, discussed in our letter report to you on June 9, 1989. The 14 retort case was extended to 17 retorts at the request of Roger Moore.

The 17 retort case requires 64 months, or 7 months longer than estimated for 14 retorts. This rate is based upon optimization of the production process and equipment. Table 1 compares the production and cost values for the 17 and 14 retort cases. The three additional retorts results in a 3 to 4 percent decrease in cost per ton. Figure 1 shows the cumulative production versus time, and Figure 2 shows the variation of cost per ton on a quarterly basis. Production costs begin to rise after the 15th quarter because production drops as the project winds down. A more detailed summary of the cost estimate is presented in the attached Table 2.

Steady state mining costs were estimated to be \$9.80 per ton by averaging operating cost per ton for the 3rd through 15th quarters when quarterly production ranged from 123,000 to 244,000 tons. After the 15th quarter, production rates begin to drop as the project winds down, and costs per ton begin to increase to the \$13 to \$17 per ton range.

Dr. Ray Zahradnik
July 6, 1989
Page 2

Table 1 Comparison of 17 and 14 Retort Cases

Item	17 Retorts	14 Retorts
Production (tons)	2,854,797	2,414,222
Total cost	\$36,240,681	\$31,930,927
Total cost per ton	\$12.69	\$13.23
Capital equipment	4,313,997	4,128,995
Operating cost	\$31,926,684	\$27,801,932
Operating cost per ton	\$11.18	\$11.52

We look forward to discussing this estimate with you in more detail.

Sincerely yours,

Carl E. Brechtel
Sr. Associate

CEB/klg

cc: Roger Moore

FIGURE 1 - CUMULATIVE PRODUCTION
17 RETORT CASE

FIGURE 2 - COMPARISON OF NORMALIZED COST
17 RETORT CASE

TABLE 2 - SUMMARY OF PRODUCTION COST AND NORMALIZED COST
OXY 17 RETORT DEMONSTRATION

ELAPSED QUARTERS	PRODUCTION (TONS)	OPERATING COSTS			OPERATING + CAP. EQUIPMENT COSTS		
		OPERATING COSTS (\$)	NORMALIZED OPERATING COST (\$/TON)	CUMULATIVE OPERATING COST (\$)	OPERATING & CAPITAL COSTS (\$)	NORMALIZED OP&CAP COST (\$/TON)	CUMULATIVE TOTAL COST (\$)
1	0	\$563,179		\$563,179	\$1,321,845		\$1,321,845
2	82,532	\$290,430	\$229.84	\$853,609	\$2,728,429	\$267.97	\$1,589,274
3	184,031	\$400,732	\$218.42	\$1,254,341	\$3,338,731	\$19.23	\$1,608,505
4	165,448	\$298,824	\$179.42	\$1,433,165	\$3,338,731	\$12.32	\$1,620,827
5	177,350	\$298,824	\$169.42	\$1,602,515	\$3,338,731	\$10.11	\$1,630,938
6	177,602	\$298,824	\$169.42	\$1,772,117	\$3,338,731	\$10.11	\$1,641,049
7	167,314	\$298,824	\$169.42	\$1,941,431	\$3,338,731	\$10.11	\$1,651,160
8	140,167	\$298,824	\$169.42	\$2,110,745	\$3,338,731	\$10.11	\$1,661,271
9	178,084	\$298,824	\$169.42	\$2,279,829	\$3,338,731	\$10.11	\$1,671,382
10	244,080	\$298,824	\$169.42	\$2,448,913	\$3,338,731	\$10.11	\$1,681,493
11	123,080	\$298,824	\$169.42	\$2,617,997	\$3,338,731	\$10.11	\$1,691,604
12	195,972	\$298,824	\$169.42	\$2,787,081	\$3,338,731	\$10.11	\$1,701,715
13	143,118	\$298,824	\$169.42	\$2,956,165	\$3,338,731	\$10.11	\$1,711,826
14	196,501	\$298,824	\$169.42	\$3,125,249	\$3,338,731	\$10.11	\$1,721,937
15	148,498	\$298,824	\$169.42	\$3,294,333	\$3,338,731	\$10.11	\$1,732,048
16	92,233	\$298,824	\$169.42	\$3,463,417	\$3,338,731	\$10.11	\$1,742,159
17	111,540	\$298,824	\$169.42	\$3,632,501	\$3,338,731	\$10.11	\$1,752,270
18	83,882	\$298,824	\$169.42	\$3,801,585	\$3,338,731	\$10.11	\$1,762,381
19	100,450	\$298,824	\$169.42	\$3,970,669	\$3,338,731	\$10.11	\$1,772,492
20	112,470	\$298,824	\$169.42	\$4,139,753	\$3,338,731	\$10.11	\$1,782,603
21	76,210	\$298,824	\$169.42	\$4,308,837	\$3,338,731	\$10.11	\$1,792,714
22	4,729	\$298,824	\$169.42	\$4,313,566	\$3,338,731	\$10.11	\$1,802,825
TOTALS	2,854,797	\$31,926,684			\$36,240,681		
AVERAGE OP/CAP COST PER TON			\$12.69				
AVERAGE OP COST PER TON			\$11.18				
STEADYSTATE COSTS (AVERAGE 3RD-15TH QUARTERS)							
OPERATING (\$/TON)		\$9.80					

TABLE 2 - SUMMARY OF PRODUCTION COST AND NORMALIZED COST
OXY 17 RETORT DEMONSTRATION

ELAPSED QUARTERS	PRODUCTION (TONS)	OPERATING COSTS			OPERATING + CAP. EQUIPMENT COSTS		
		OPERATING COSTS (\$)	NORMALIZED OPERATING COST (\$/TON)	CUMULATIVE OPERATING COST (\$)	OPERATING & CAPITAL COSTS (\$)	NORMALIZED OPE&CAP COST (\$/TON)	CUMULATIVE TOTAL COST (\$)
1	62,332	\$583,179		\$583,179	\$1,421,845		\$1,421,845
2	184,031	\$1,290,430	\$29.84	\$1,873,609	\$2,728,429	\$87.97	\$4,250,274
3	185,448	\$1,100,732	\$11.42	\$2,974,341	\$3,828,731	\$19.23	\$4,250,274
4	148,350	\$1,358,162	\$9.42	\$4,332,503	\$5,191,731	\$12.32	\$5,203,005
5	177,802	\$1,489,974	\$10.11	\$5,822,477	\$6,680,955	\$12.32	\$6,828,700
6	187,314	\$1,811,438	\$9.07	\$7,633,915	\$8,492,974	\$10.11	\$7,828,674
7	140,187	\$1,584,107	\$9.47	\$9,218,022	\$9,811,438	\$8.07	\$8,938,112
8	178,194	\$1,475,009	\$10.52	\$10,693,031	\$11,189,307	\$8.47	\$9,927,419
9	244,080	\$1,823,373	\$9.20	\$12,516,404	\$12,495,009	\$10.52	\$11,997,428
10	123,175	\$1,593,875	\$8.53	\$14,110,279	\$13,823,373	\$8.20	\$12,820,803
11	143,118	\$1,587,631	\$12.73	\$15,697,910	\$15,483,873	\$8.33	\$13,919,214
12	153,972	\$1,852,159	\$8.43	\$17,549,369	\$17,853,631	\$12.73	\$15,200,782
13	143,118	\$1,895,884	\$11.15	\$19,445,253	\$19,853,631	\$8.43	\$16,434,468
14	196,501	\$1,824,357	\$8.27	\$21,269,610	\$21,853,631	\$11.15	\$17,549,871
15	148,498	\$1,639,185	\$11.04	\$22,908,795	\$23,853,631	\$8.27	\$18,654,889
16	92,233	\$1,313,971	\$16.41	\$24,222,766	\$25,853,631	\$11.04	\$19,769,904
17	111,340	\$1,355,808	\$13.02	\$25,578,574	\$26,853,631	\$16.41	\$20,934,025
18	83,382	\$1,450,179	\$16.14	\$27,028,753	\$27,853,631	\$13.02	\$22,064,161
19	100,450	\$1,410,179	\$14.04	\$28,438,932	\$28,853,631	\$16.14	\$23,220,286
20	112,470	\$1,462,313	\$13.00	\$29,901,245	\$29,853,631	\$14.04	\$24,361,967
21	76,210	\$1,338,940	\$17.34	\$31,240,185	\$30,853,631	\$13.00	\$25,496,146
22	4,729	\$415,082	\$87.77	\$31,655,267	\$31,311,802	\$17.34	\$26,668,559
TOTALS		2,854,797	\$31,928,884		\$38,240,681		
AVERAGE OPE&CAP COST PER TON			\$12.89				
AVERAGE OF COST PER TON			\$11.18				
STEADYSTATE COSTS (AVERAGE 3RD-15TH QUARTERS)							
OPERATING (\$/TON)			\$9.80				

COMPARISON OF NORMALIZED COST 17 RETORT CASE

QRY 17 RETORT DEMONSTRATION PROJECT OPERATING COSTS EXCLUDING CAPTITAL EQUIPMENT

[illegible]

01-Apr-93

01-Jul-93

01-Oct-93

01-Jan-94

01-Apr-94

01-Jul-94

01-Oct-94

\$198,110
\$164,000
\$117,700
\$27,931
\$44,331
\$679,173
\$18,400
\$51,800
\$273,375
\$24,639
\$7,812
\$16,338

\$198,110
\$95,000
\$102,000
\$163,207
\$679,173
\$77,700
\$273,375
\$24,639
\$7,812
\$16,338

\$80,512
\$118,700
\$97,981
\$2,875
\$136,767
\$679,173
\$77,700
\$273,375
\$24,639
\$7,812
\$16,338

\$198,110
\$163,000
\$196,500
\$183,000
\$679,173
\$89,172
\$273,375
\$24,639
\$7,812
\$16,338

\$198,110
\$68,713
\$49,000
\$146,568
\$123,922
\$679,173
\$89,172
\$273,375
\$24,639
\$7,812
\$16,338

\$198,110
\$49,000
\$146,568
\$123,922
\$679,173
\$89,172
\$273,375
\$24,639
\$7,812
\$16,338

\$198,110
\$195,470
\$165,155
\$679,173
\$100,551
\$273,375
\$24,639
\$7,812
\$16,338

\$1,624,557

\$1,639,165

\$1,513,971

\$1,452,136

\$1,355,806

\$1,410,179

\$1,462,513

KEY COST MODEL FOR 17 RETORT DEMONSTRATION - TOTAL COST (OPERATING AND AMORTIZED CAPITAL)

DESCRIPTION	01-Jan-90	01-Apr-90	01-Jul-90	01-Oct-90	01-Jan-91	01-Apr-91
START/ORG	\$0	\$0	\$0	\$0	\$0	\$0
LINE SH	\$20,000	\$0	\$0	\$0	\$0	\$0
PUR SH	\$0	\$0	\$0	\$0	\$0	\$0
SHAFT BOT	\$20,000	\$0	\$0	\$0	\$0	\$0
TEMP. GR	\$40,000	\$0	\$0	\$0	\$0	\$0
BYD. EX	\$15,000	\$0	\$0	\$0	\$0	\$0
REC. SH	\$0	\$0	\$0	\$0	\$0	\$0
MINE OR	\$0	\$27,488	\$0	\$0	\$0	\$0
MINE SHOP	\$0	\$27,224	\$0	\$0	\$0	\$0
OFF-GAS S	\$0	\$0	\$0	\$0	\$0	\$0
CONST. SH	\$0	\$107,000	\$0	\$0	\$0	\$0
ERR-918 L	\$0	\$5,000	\$0	\$0	\$0	\$0
MINE CRSE	\$0	\$8,333	\$0	\$0	\$0	\$0
BORE OR	\$0	\$121,333	\$18,667	\$0	\$0	\$0
CONST. CR	\$0	\$0	\$127,500	\$0	\$0	\$0
INST. CR	\$0	\$0	\$127,500	\$0	\$0	\$0
L&P 4	\$0	\$42,182	\$0	\$0	\$0	\$0
FC 3	\$0	\$29,787	\$23,143	\$0	\$0	\$0
FC 1	\$0	\$0	\$81,456	\$0	\$0	\$0
FC 6	\$0	\$0	\$43,310	\$0	\$0	\$0
FC 9	\$0	\$0	\$32,410	\$0	\$0	\$0
LL DOORS	\$0	\$29,154	\$44,000	\$0	\$0	\$0
LC 1	\$0	\$0	\$113,387	\$137,000	\$0	\$0
UL DOORS	\$0	\$0	\$40,540	\$0	\$0	\$0
LC 2	\$0	\$0	\$37,849	\$0	\$0	\$0
UL DOORS	\$0	\$0	\$44,000	\$0	\$0	\$0
LC 1	\$0	\$0	\$63,500	\$154,400	\$0	\$0
LC 2	\$0	\$0	\$41,421	\$0	\$0	\$0
LC 3	\$0	\$0	\$45,282	\$0	\$0	\$0
LC DOORS	\$0	\$0	\$44,000	\$0	\$0	\$0
LC 1	\$0	\$0	\$61,289	\$193,548	\$193,548	\$61,289
LC 2	\$0	\$0	\$0	\$23,033	\$35,787	\$35,787
LC 3	\$0	\$0	\$0	\$0	\$75,897	\$7,421
LC 4	\$0	\$0	\$0	\$23,228	\$7,213	\$0
LC 5	\$0	\$0	\$0	\$0	\$17,158	\$0
LC 6	\$0	\$0	\$0	\$0	\$138,181	\$88,717
LC 7	\$0	\$0	\$0	\$0	\$0	\$37,339
LC 8	\$0	\$0	\$0	\$0	\$0	\$29,188
LC 9	\$0	\$0	\$0	\$0	\$0	\$49,495
LC 10	\$0	\$0	\$0	\$0	\$0	\$85,222
LC 11	\$0	\$0	\$0	\$0	\$0	\$31,190
LC 12	\$0	\$0	\$0	\$0	\$0	\$56,103
LC 13	\$0	\$0	\$0	\$0	\$0	\$85,180
LC 14	\$0	\$0	\$0	\$0	\$0	\$31,163
LC 15	\$0	\$0	\$0	\$0	\$0	\$31,712
LC 16	\$0	\$0	\$0	\$0	\$0	\$2,706
LC 17	\$0	\$0	\$0	\$0	\$0	\$0
LABOR1	\$262,623	\$0	\$0	\$0	\$0	\$0
LABOR2	\$0	\$542,109	\$0	\$0	\$0	\$0
LABOR3	\$0	\$0	\$679,173	\$679,173	\$679,173	\$679,173
DEWATER1	\$10,304	\$5,152	\$0	\$0	\$0	\$0
DEWATER2	\$0	\$14,380	\$7,190	\$0	\$0	\$0
DEWATER3	\$0	\$0	\$17,192	\$25,789	\$8,596	\$33,375
DEWATER4	\$0	\$0	\$0	\$0	\$22,250	\$0
DEWATER5	\$0	\$0	\$0	\$0	\$0	\$0
DEWATER6	\$0	\$0	\$0	\$0	\$0	\$0
DEWATER7	\$0	\$0	\$0	\$0	\$0	\$0
DEWATER8	\$0	\$0	\$0	\$0	\$0	\$0
DEWATER9	\$0	\$0	\$0	\$0	\$0	\$0
SUPPLY1	\$105,434	\$105,434	\$273,375	\$273,375	\$273,375	\$273,375
SUPPLY2	\$0	\$91,125	\$0	\$0	\$0	\$0
SUPPLY3	\$0	\$0	\$0	\$0	\$0	\$0
SUPPLY4	\$0	\$0	\$0	\$0	\$0	\$0
SUPPLY5	\$0	\$0	\$0	\$0	\$0	\$0
SUPPLY6	\$0	\$0	\$0	\$0	\$0	\$0
SHAFT HEA	\$16,426	\$24,639	\$24,639	\$24,639	\$24,639	\$24,639
VENT DUCT	\$62,500	\$93,750	\$93,750	\$0	\$0	\$0
REP VENT	\$0	\$0	\$0	\$7,812	\$7,812	\$7,812
SHOTCRETE	\$10,892	\$18,338	\$18,338	\$18,338	\$18,338	\$18,338
CAPITAL E	\$958,666	\$1,437,999	\$1,437,999	\$478,333	\$0	\$0
QUARTERLY TOTAL OPERATING COST	\$1,521,845	\$2,728,429	\$3,538,731	\$2,037,695	\$1,499,974	\$1,611,438
TOTAL PROJECT OPERATING COST	\$36,240,681					

01-Jul-91	01-Oct-91	01-Jan-92	01-Apr-92	01-Jul-92	01-Oct-92	01-Jan-93
\$217,000	\$143,422					
\$170,100	\$10,578					
\$162,300	\$65,874					
	\$10,175					
	\$2,500					
	\$38,680	\$9,113				
	\$57,103	\$188,740	\$219,175	\$8,473		
	\$19,138	\$37,386	\$100,267			
	\$32,136	\$113,425				
	\$32,224	\$67,525				
	\$20,613	\$161,460	\$52,959			
				\$41,439		
				\$22,720		
				\$79,906	\$221,143	\$121,545
				\$78,974	\$168,815	\$900
				\$45,974		
				\$970,812	\$89,627	\$89,231
				\$159,669		\$74,153
					\$44,877	\$91,526
					\$70,959	\$161,760
\$679,173	\$679,173	\$679,173	\$679,173	\$679,173	\$679,173	\$679,173
\$33,300	\$11,100	\$44,388	\$44,388	\$14,796	\$55,401	\$55,401
	\$29,592			\$36,934		
\$273,375	\$273,375	\$273,375	\$273,375	\$273,375	\$273,375	\$273,375
\$24,639	\$24,639	\$24,639	\$24,639	\$24,639	\$24,639	\$24,639
\$7,812	\$7,812	\$7,812	\$7,812	\$7,812	\$7,812	\$7,812
\$16,338	\$16,338	\$16,338	\$16,338	\$16,338	\$16,338	\$16,338
\$1,584,307	\$1,475,009	\$1,623,375	\$1,593,875	\$1,567,631	\$1,652,159	\$1,595,864

01-Apr-93

01-Jul-93

01-Oct-93

01-Jan-94

01-Apr-94

01-Jul-94

01-Oct-94

\$198,144

\$164,663

\$117,761

\$27,931

\$44,382

\$679,173

\$19,488

\$51,867

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$198,144

\$95,998

\$102,888

\$163,207

\$679,173

\$77,793

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$80,513

\$116,705

\$97,981

\$2,874

\$136,767

\$679,173

\$77,793

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$196,584

\$165,433

\$679,173

\$89,172

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$196,584

\$68,713

\$679,173

\$89,172

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$49,080

\$146,658

\$123,922

\$679,173

\$89,172

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$195,470

\$163,114

\$679,173

\$100,551

\$273,375

\$24,639

\$7,812

\$16,338

\$0

\$1,624,557

\$1,639,165

\$1,513,971

\$1,452,136

\$1,355,806

\$1,410,179

\$1,462,513

CUMULATIVE PRODUCTION
17 RETORT CASE

[illegible]

[illegible]

Quarter	0-14	15-24	25-34	35-44	45-54	55-64	65-74
01-Jan-93	143,118	35,268	28,832	21,019	44,964	4,465	7,433
01-Apr-93	196,501	46,874	64,024	27,211	32,198	53,603	32,198
01-Jul-93	148,498	27,211	64,024	27,211	5,195	52,069	5,195
01-Oct-93	92,233	26,013	38,187	28,031	28,031	28,031	28,031
01-Jan-94	111,540	64,324	47,216	47,216	47,216	47,216	47,216
01-Apr-94	83,982	64,324	19,658	19,658	19,658	19,658	19,658
01-Jul-94	100,450	16,060	48,606	35,784	35,784	35,784	35,784

01-Oct-94

01-Jan-95

01-Apr-95

01-Jul-95

TOTAL

64,780
47,69064,780
11,4304,729
0

112,470

76,210

4,729

0 *****

9,404
9,5588,558
93113,875
18,500
26,450
14,646
20,96784,386
11,819
11,04984,170
12,076
13,361153,489
19,785
26,48910,175
5,653
75,24010,175
8,890
122,61518,243
61,601
18,50026,449
10,175
10,17575,240
10,175
8,890122,615
18,243
61,60118,500
26,449
10,17510,175
75,240
10,1758,890
122,615
18,50061,601
41,857
113,107182,885
94,904
41,857113,107
182,885
94,904

J. F. T. AGAPITO & ASSOCIATES, INC.
CONSULTING GEOTECHNICAL AND MINING ENGINEERS
715 HORIZON DRIVE, SUITE 340
GRAND JUNCTION, COLORADO 81506

139-1

July 10, 1989

Dr. Ray Zahradnik
Occidental Oil Shale, Inc.
1250 South Lincoln Avenue, Suite I-5
P. O. Box 880408
Steamboat Plaza
Steamboat Springs, CO 80488

Re: Occidental C-b; Estimated Steady State Mining Cost for Commercial Scale

Dear Ray:

This letter presents the results of our estimate of the steady state mining costs to excavate upper, lower, intermediate and product levels from the existing C-b shaft facilities. The estimate is based upon plans for developing the first retorts at the north end of the C-b tract, as per the Cathedral Bluffs Shale Oil Co. drawings that are listed in the table in Attachment A.

The costs are limited to the underground activities required to complete retort development excavations for input to Roger Moore's overall project cost estimate.

Costs include:

- shaft station developments and support facilities (shops, storage, loading, power centers, and pump stations, etc.)
- mining equipment (LHD, trucks, bolters, scalers, etc.)
- ore transport (feeder breakers, conveyors)
- face ventilation
- ore passes, off-gas shaft, and ventilation exhaust shaft
- ramps between levels
- main entries to panels on each level
- face ventilation equipment and ventilation control structures
- break through to V-E shaft on panel advance
- supplies, maintenance and power

- dewatering

Specific underground operations that are not included are:

- rubbilization,
- hoisting of ore,
- retorting operations, and
- surface facilities, operations and support.

We have also assumed that the underground planning and engineering activities will be carried out by an overall site group that is separate from the mining production operation. Main ventilation equipment was not included because OXY has a large main fan in storage. Sales taxes were not considered on materials or equipment purchases.

The results of the estimate are listed in Table 1. The total cost per ton was estimated at \$11.66 by distributing the capital equipment and development costs over five years (3.8 panels, 136 retorts). Average operating costs during the five year period were predicted to be \$9.62 per ton. These costs are projected at constant value dollars. Tables containing more detailed breakdowns of the estimated costs are presented in Attachment B.

Table 1 Estimated Mining Production Costs for 27.5 Retorts per Year with Capital Costs Amortized over Five Years (3.8 Panels, 36 Retorts per Panel)

	Amortization Period (years)	Estimated Cost* (\$)	Annual Production (tons)	Mining Cost* (\$/ton)	Annual Cost* (\$)
Capital equipment	5	\$25,513,000			\$5,102,600
Capital development	5	\$22,320,000			\$4,464,000
Labor	1				\$14,254,300
Direct mining			4,700,000	\$3.06	\$14,382,000
Indirect mining	1	\$16,586,000			\$16,586,000
Subtotals			4,700,000		\$54,788,900
Total cost per ton (\$/ton)				\$11.66	
Operating cost per ton (\$/ton)				\$9.62	

* Constant dollars

Dr. Ray Zahradnik
July 10, 1989
Page 3

The steady state costs are expected to lie between \$9.62/ton and \$11.66/ton because the commercial operation requires continued installation of some items considered capital in our start-up analysis. This includes off-gas shafts, ventilation exhaust shafts, main entry developments and major equipment replacement.

Generation of the commercial scale estimate was not supported by the level of detail used in our analysis of the 14 and 17 retort demonstration project.

Sincerely yours,

Carl E. Brechtel
Senior Associate

CEB/kg

cc: Roger Moore

ATTACHMENT A

C-b Drawings Used in the Analysis

CATHEDRAL BLUFFS SHALE OIL COMPANY DRAWINGS USED IN ANALYSIS

DRAWING NO.	TITLE
ND-0515-M	INITIAL MINE AND PLANT PILLAR LAYOUT
ND-0507-M	AIR & UPPER LEVEL STATION DEVELOPMENT
ND-0508M	INTERMEDIATE LEVEL STATION DEVELOPMENT
ND-0509-M	LOWER LEVEL STATION & RAMP DEVELOPMENT
ND-0511-M	MIS UPPER VOID LEVEL
ND-0512-M	MIS INTERMEDIATE VOID LEVEL
ND-0514-M	LOWER VOID/PRODUCT LEVEL
ND-0516-M	MIS RETORT BOTTOM DRAWPOINT DESIGN
TD-0505-M	MIS VENTILATION PLAN UPPER LEVEL
TD-0505-M	MIS VENTILATION PLAN INTERMEDIATE LEVEL
TD-0506-M	MIS VENTILATION PLAN LOWER LEVEL

ATTACHMENT B

Mine Labor, Indirect, Capital and Direct Cost Estimates

TABLE B1 ESTIMATED CB MINING OPERATIONS LABOR COSTS

NUMBER OF STAFF	JOB TITLE	SALARY	ANNUAL
1	MINE MANAGER	60000	\$84,000
2	MINE ENGINEER	40000	\$112,000
4	ENGINEER TECH	25000	\$140,000
2	SECRETARY	12000	\$33,600
3	MAINT SUPT	35000	\$147,000
3	MINE SUPT	40000	\$168,000
6	SHIFT FOREMAN	35000	\$294,000
6	MAINT FORMAN	35000	\$294,000
27	OVERHEAD & SALARY		\$1,272,600
		HOURLY WAGE	
18	JUMBO OP I	16.60	\$1,196,395
18	HELPER III	13.00	\$936,936
3	BENCH DRILLER	13.00	\$156,156
3	HELPER	9.50	\$114,114
12	POWDERMAN	13.00	\$624,624
12	HELPER	9.50	\$456,456
30	918 OPER	16.60	\$1,993,992
12	SCALER OPER	16.60	\$797,597
9	BULL GANG LEAD	13.00	\$468,468
27	BULL GANG	9.50	\$1,027,026
3	TOP LANDER	9.50	\$114,114
3	TOP LANDER OP	13.00	\$156,156
9	CRUSHER OP	16.60	\$598,198
9	HELPER	9.50	\$342,342
6	SKIP TENDER	9.50	\$228,228
12	MECHANIC I	16.60	\$797,597
24	MECHANIC II	13.00	\$1,249,248
12	MECHANIC III	9.50	\$456,456
12	OILER	9.50	\$456,456
6	ELECTRICIAN	16.60	\$398,798
6	HELPER	13.00	\$312,312
246	TOTAL HOURLY		\$12,881,669
273	TOTAL SAL&HOUR		\$14,154,269

TABLE B2 CB INDIRECT UNDERGROUND MINING OPERATING COSTS

			DOLLARS PER MONTH
0	WATER TRUCK	20 \$/HR	\$6,000
0	FUEL TRUCK	20 \$/HR	\$18,000
0	MECH TRUCK	20 \$/HR	\$48,000
0	COMPRESSOR	20 \$/HR	\$24,000
0	MAN LIFT	30 \$/HR	\$18,000
	PIPE	10 \$/FT AD	\$60,000
0	AIR LINE	5 \$/FT AD	\$30,000
0	HOSE	4 \$/FT AD	\$24,000
0	ELETRICS		\$30,000
0	CABLES	3 \$/FT AD	\$18,000
0	FANS	200 \$/FAN/M	\$9,000
0	STOPPINGS	3000 \$/X CUT	\$27,500
0	MISC VENT	10 % STOPP	\$2,750
	ELEC POWER	0.024 \$/KWH	\$120,000
	CRUSHING	1.00 \$/TON	\$392,000
	DEWATERING		\$75,000
	MN AIR HEAT	2.00 \$/MCF	\$23,400
	ORE PASSES	240000 \$ EA	\$92,000
	SHOTCRETE	300.00 \$/CY	\$320,000
OVERHEAD			
0	SUPPLY & TRAINING		\$9,000
0	COMMUNICATION		\$5,000
0	TRAVEL		\$10,000
0	RELOCATION EXP		\$2,000
0	RECRUITING		\$5,000
0	INSTRUMENTATION		\$3,500
0	ROPE SOAP & DOPE		\$10,000
TOTAL COST PER MONTH			\$1,382,150
ESTIMATED ANNUAL COST			\$16,585,800

TABLE B3 ESTIMATED CAPITAL EQUIPMENT AND DEVELOPMENT COSTS

DESCRIPTION	PERMISSABLE YES NO	UNIT COST	NO. OF UNITS	TOTAL COST
TWIN BOOM JUMBO	Y	\$550,000	6	\$3,300,000
CABLE REEL TRUCK	Y	\$25,000	6	\$150,000
ROOF BOLTER	Y	\$400,000	4	\$1,600,000
CABLE REEL TRUCK	N	\$25,000	1	\$25,000
BENCH DRILL	N	\$325,000	1	\$325,000
JACKLEGS	N/A	\$10,000	10	\$100,000
SHOTCRETE PLANT	N/A	\$60,000	2	\$120,000
EIMCO 918LHD	Y	\$350,000	1	\$350,000
EIMCO 913 LHD	Y	\$145,000	1	\$145,000
EIMCO 983-T15 DUMP TRUCK	N	\$125,000	2	\$250,000
SCALER	Y	\$290,000	4	\$1,160,000
POWDER TRUCK	Y	\$120,000	4	\$480,000
UTILITY LIFT TRUCK	Y	\$100,000	3	\$300,000
ELEVATING PLATFORM TRK	Y	\$120,000	3	\$360,000
CRUSHER CLEANUP LOADER	N	\$70,000	1	\$70,000
MECHANICS TRUCK	N	\$70,000	2	\$140,000
TRACTOR WATER	N	\$14,000	3	\$42,000
TRACTOR VENT CREW	N	\$14,000	3	\$42,000
TRACTOR MECHANICS	N	\$14,000	2	\$28,000
TRACTOR UTILITY	N	\$14,000	2	\$28,000
TANKER FUEL	N/A	\$10,000	2	\$20,000
TANKER WATER	N/A	\$10,000	6	\$60,000
MATERIAL TRAILER	N/A	\$8,000	6	\$48,000
POWDER TRAILER	N/A	\$15,000	8	\$120,000
AUX FANS		\$35,000	45	\$1,575,000
DUCTING		\$600,000	1	\$600,000
COMPRESSORS		\$80,000	4	\$320,000
AIR LINE		\$90,000	1	\$90,000
SHOP TOOLS		\$1,000,000	1	\$1,000,000
CRUSHER		\$400,000	3	\$1,200,000
MAIN CONVEYORS		\$650,000	2	\$1,300,000
FEEDER CONVEYORS		\$250,000	3	\$750,000
TRANSFER CONVEYOR		\$500,000	3	\$1,500,000
LOADOUT CONVEYORS		\$200,000	4	\$800,000
SURVEY EQUIP		\$75,000	1	\$75,000
MONITORING SYSTEM		\$250,000	1	\$250,000
RAISE BORE		\$1,700,000	1	\$1,700,000
SPM STOWER		\$210,000	1	\$210,000
SAFETY EQUIP		\$90,000	1	\$90,000
ELECTRIC SUBSTATIONS		\$30,000	8	\$240,000
CAPITAL EQUIPMENT COSTS				\$25,513,000
MINE FAN INSTALLATION		100000	1	\$100,000
SHAFT BOTTOM RAMP		800000	1	\$800,000
UL TO IL RAMP		600000	1	\$600,000
IL TO LL RAMP		600000	1	\$600,000
LL TO IL CONV RAMP		420000	1	\$420,000
SHOP EXCAVATION		1600000	1	\$1,600,000
LOADOUT FACILITIES		2300000	1	\$2,300,000
PUMP STATION		1000000	1	\$1,000,000
OFF-GAS SHAFT LINED		6900000	1	\$6,900,000
EXHAUST VENT SHAFT		4000000	1	\$4,000,000
SHAFT STATION DEVELOPMENT		4000000	1	\$4,000,000
CAPITALIZED DEVELOPMENT				\$22,320,000
TOTAL CAPITAL DOLLARS				\$47,833,000

TABLE B4 - ESTIMATED CB DIRECT UNDERGROUND MINING COST

LEVEL	TONNAGE (TONS)	COST (\$)	COST PER TON
PRODUCT	26,449	\$80,155	3.03
LOWER	75,240	\$214,553	2.85
INTERMEDIATE	122,515	\$389,307	3.18
UPPER	61,601	\$190,855	3.10
.....			
TOTAL	285,805	\$874,870	
.....			
WEIGHTED AVERAGE COST		\$3.06	
.....			
ESTIMATED ANNUAL PRODUCTION (TONS)		4,700,000	
.....			
ESTIMATED ANNUAL DIRECT COST		\$14,387,044	

TABLE B4 - ESTIMATED CB DIRECT UNDERGROUND MINING COST

LEVEL	TONNAGE (TONS)	COST (\$)	COST PER TON
PRODUCT	26,449	\$80,155	3.03
LOWER	75,240	\$214,553	2.85
INTERMEDIATE	122,515	\$389,307	3.18
UPPER	61,601	\$190,855	3.10
TOTAL	285,805	\$874,870	
WEIGHTED AVERAGE COST		\$3.06	
ESTIMATED ANNUAL PRODUCTION (TONS)		4,700,000	
ESTIMATED ANNUAL DIRECT COST		\$14,387,044	