OIL SHALE
COAL
OIL SANDS

synthetic fuels

VOLUME 10 • NUMBER 4 DECEMBER, 1973

quarterly report

CAMERON ENGINEERS

synthetic fuels

OIL SHALE ○ COAL ○ OIL SANDS

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APPENDIX

H I G H L I G H T S

Interior's Oil Shale Leasing Program Moving Ahead--First Lease Sale Scheduled For January 8, 1974

Secretary Morton announced his decision to proceed with the program on November 28. The announcement was delayed several days by numerous last minute comments submitted by environmental groups, most of whom ask for a further delay or total abandonment of leasing plans. A lawsuit appears to be a likely possibility.

Morton's announcement, the final lease form and other details are reviewed beginning on *page 2-28*. The formal sale notice and the lease are reproduced in the Appendix starting on *page A-90*.

Colony Describes Pipeline Route in Environmental Report

The 180-mile route shown in the report, prepared by Utah Environmental and Agricultural Consultants, extends from north of Grand Valley, Colorado to a point near Aneth in southeastern Utah. *See page 2-25*.

Paraho Retorting Project to Proceed with 15 Participants

Firms recently joining the project are Mobil, Sun, Texaco, ARCO, Phillips and a group headed by Webb Resources of Denver. Paraho is expected to activate the 5-year lease of the Bureau of Mines Anvil Points Demonstration facility before the end of this year and start construction of a pilot retort shortly thereafter. *See page 2-23*.

Flat Tops Wilderness Proposal Affects Water Availability in Piceance Basin

It is probable that Congress will include the Meadows area on the South Fork of the White River in the wilderness designation, thus precluding a water development project proposed by Rocky Mountain Power Company that would divert water from the White River to the Colorado River. It would also eliminate the possibility of using White River Basin water in exchange for water diverted to Colorado's Eastern Slope. *See page 2-8 for more details*.

Canadian Participation and Royalty Provisions Described in Letter Agreement Between Syncrude and Province of Alberta

A definition of project ownership and royalty was the last major hurdle to cross before the Syncrude group could proceed with their commercial venture. The terms announced in the September 14th letter agreement, however, leave Syncrude facing uncertainty, and events occurring since September 14 have resulted in a clouded political situation in Canada that only compounds the uncertainty. Despite the situation, it appears likely that Syncrude will proceed with the project. For a more detailed review, *see page 3-24*. The letter agreement is reproduced at *page A-67*.

Alberta ERCB Recommends Approval of Changes in Syncrude's Commercial Plans

Earlier this year, Syncrude submitted applications to the Board asking for certain technical changes and a delay in the start-up of the proposed 125,000-Bpd, $744 million plant. The Board's recommendations are contained in a report issued on September 10. That report is discussed on *page 3-18;* the Board's findings, decision and form of approval are reproduced in the Appendix, *page A-58*.

Alberta ERCB Accepts Shell's Application for Commercial Oil Sands Project

Formally accepted in late August of this year, the application submitted by Shell Canada Ltd. and Shell Explorer Ltd. describes a $710 million venture with the ultimate goal of producing 100,000-Bpd by early 1982. Surface mining will be accomplished by draglines. The K. A. Clark hot water process will be employed for bitumen extraction. Recoverable reserves are said to be sufficient to sustain a 100,000-Bpd operation for 80 to 90 years. The application is reviewed on *page 3-11* and a copy reproduced in the Appendix, *page A-1*.

Occidental Reports Success With In Situ Experiment

Initiated last February, the in situ test is said to be producing 25-30 Bpd at yields in excess of 50 percent. *See page 2-23* for more information.

GCOS Granted Allowable Production Increase

The ERCB's recommended approval appears in a report issued November 20. Formal approval by the Lieutenant Governor in Council is expected by the end of the year. GCOS will thus be permitted to increase production from 45,000 to 65,000-Bpd. Because production has exceeded allowable in the past, GCOS allowable in 1974 will be only 60,515-Bpd. This makes no difference since GCOS contemplates an average 1974 production of only 59,000-Bpd anyhow. Only minor mine and plant operational changes will be required to achieve the increase desired.

HIGHLIGHTS

The ERCB actually reached their decision on June 18, 1973 but withheld formal release until the Alberta Environmental Department confirmed the Board's findings relating to environmental matters. The Board's report is reviewed at *page 3-24*. A copy of the form of approval is reproduced at *page A-85*.

GCOS financial data and production statistics are discussed on *page 3-16*.

Four Companies Announce Wyoming-based Coal Projects

Announcements during recent months indicate the role Wyoming (indeed all western states) could play in supplying the Nation's energy needs. Transcontinental Gas Pipe Line Corp., Texaco Inc., Panhandle Eastern Pipe Line Co. and Carter Oil Co. are the companies which made the announcements, *see page 4-39*.

Cost Are Rising!

El Paso Natural Gas Company filed a supplement to its FPC application concerning its Burnham Coal Gasification Project. Sharp increases in capital costs are among the changes. *See page 4-33*.

Piceance Creek Basin Oil Shale Corehole Map Updated

First prepared in June 1969, the current version of the map includes more than 100 additional coreholes and assayed wells that have been drilled in the Basin since 1969. Some 34 coreholes have been drilled during Interiors prototype leasing program. For more information, *see page 2-3*. The map and accompanying booklet are located in the *pocket inside the back cover*.

Rainbow Bridge Decision Appealed to Supreme Court

On August 10, 1973 the 10th U.S. Circuit Court of Appeals ruled in a 5-2 decision that Congress had, by implication, repealed two provisions of the 1956 Colorado River Storage Act which were intended to prevent water from entering the national monument. The case has now been appealed to the Supreme Court. Refer to *page 1-18 for details*.

EDF Suit Places Yet Another Obstacle in the Path of Coal Development

In a suit filed in the U.S. District Court at Billings, Montana the Environmental Defense Fund and others asked that certain industrial water rights necessary for western coal development be revoked. This suit is discussed on *page 4-44*.

HIGHLIGHTS

Northern Great Plains Resource Program Progressing

The status of the NGPRP is reviewed along with reviews of recently issued work group reports. An interim report is due June, 1974. *See page 4-26.*

We Can Expect the Ultimate Exhaustion of Our Fossil Fuel Resources About Year 2000

This startling statement is made by Rep. Morris Udall in a 19-page report to the Chairman of the House Interior Committee. The report, "America's Energy Potential: A Summary and Explanation," describes the status of oil & gas, coal, and nuclear, solar and geothermal energy.

The obvious danger in such a cursory treatment of an exceedingly complex subject is the unavoidable prevalence of over simplifications and fallacies. For example, the report forecast a peak domestic oil production of 12 million barrels daily. If that is true, how can domestic oil reserves possibly be exhaused by the end of the century? For a more thorough review, *see page 1-1.*

Water Seen as Key to Future Western Coal Development

The NAS study of the Potential of Rehabilitating Land Surface Mined for Coal in the Western United States points out the impact of water availability. The study was released early to several congressman and may have influenced voting on Congressional surface mining legislation. The study is reviewed on *page 4-41.*

Who is Studying What?

Coal-related studies abound. A number of studies related to western coal development are recapped on *page 4-47.*

Computer Study of Water Availability for Oil Shale Development in Colorado Completed

CORSIM II is the name of the privately-sponsored study aimed at developing a computer model of water availability in the Colorado and White River Basins in western Colorado. Data compiled during the study are not publicly available but it is possible to purchase the computer model which is adaptable to other river basins. For more information, *see page 2-7.*

STATUS OF SYNFUELS PROJECTS

Synthetic Fuels From Petroleum

Italics denote changes since September 1973 issue

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Algonquin SNG Inc., a subsidiary of Algonquin Gas Transmission Co.	Commercial plant SNG from naphtha	Designed capacity is 120 MMcfd from 27,200 BPD of naphtha to be supplied by Exxon. Plant designed and built at Freetown, Mass. by Lummus Co. Basic process design was by Humphreys & Glasgow Ltd. The CRG process is being used. *Production over Algonquin customer needs will be sold to Texas Eastern.* Project Cost estimated at $39.5 million.	*Construction nearly completed; operation expected in late 1973*
Apco Oil Corp.	Commercial plant SNG from naphtha	Capacity is 125 MMcfd from 26,000 Bpd of naphtha to be supplied by New England Petroleum Corp. from its Freeport, Bahamas refinery. Estimated SNG cost is $1.05-$1.13/Mcf. Columbia Gas System will purchase the gas. The Lurgi Gasynthan Process will be used. Stone & Webster has been awarded the engineering contract for the plant to be located in eastern Pennsylvania. Project Cost estimated at $30 million.	Final contract negotiations underway. Plant planned to be in operation by November 1, 1975
Ashland Oil Inc.	Commercial plant SNG from light petroleum liquids	Capacity is 60 MMcfd from light petroleum liquids. Foster Wheeler Corp. has been contracted to design and construct the plant at Ashland's Buffalo, N.Y. refinery. The plant will use the CRG process licensed by the British Gas Council. Estimated gas cost is $1.35-$1.40/Mcf. Iroquois Gas Company will purchase the gas. Project Cost - plant cost estimated at $10 million.	Construction was to have been completed by October 1, 1973
Baltimore Gas & Electric	*Commercial plant SNG from naphtha*	*Capacity is 60 MMcfd which will be used to supplement the company's gas supply at times of peak loads. Total estimated cost is $25 million. At full capacity, the plant will use 500,000 gallons of naphtha per day. The plant will use the BASF/Lurgi Gasynthan process. Stone & Webster Engineering Co. has an engineering, procurement and construction contract for the plant. Plant will be located in eastern Baltimore County, Md.*	*Scheduled to begin construction Fall, 1973*
Boston Gas Co.	Commercial plant SNG from LPG	Capacity is 40 MMcfd from propane using Japanese MRG process. Provisions will be made for conversion to naphtha feed. The Badger Co., Inc. will engineer and construct the plant from design specifications developed by Universal Oil Products Co. UOP is process licensor. The plant site is located in Everett, Mass. *The feedstock will be supplied by Exxon.* Project Cost estimated at $7 million.	Construction began Jan. 17, 1973. Completion scheduled for December, 1973
Brooklyn Union Gas Co.	Commercial plant SNG from naphtha	Capacity is 50-60 MMcfd from 10,000 Bpd naphtha to be supplied by Exxon. Plant location is Brooklyn. Estimated gas cost is $1.60. CRG process will be used. Completion scheduled for January 1974 running 12 weeks late. Plant to run 180 days/yr. Construction by Lummus Co. was started in May, 1972. Project Cost estimated at $26 million.	Under construction
Central Illinois Light Co.	Commercial plant SNG from naphtha	Designed capacity is 60 MMcfd from 12,000 Bpd of naphtha. CRG process will be used. Plant location in Peoria, Illinois *Project Cost estimated at $24 million.*	Feasibility study completed
Cities Service S-G, Inc. a subsidiary of Cities Service Co.	Commercial plants SG from naphtha	Plant planned at Diamond, Mo. with capacity of 125 MMcfd from 25,200 Bpd of naptha from 100,000 Bpd of imported crude and unfinished oils. Stone and Webster completed preliminary designs of the plant. The plant will use the BASF/Lurgi Gasynthan process. Completion has been tentatively set for fall 1975. Project Cost estimated at $42.8 million.	FPC application has been filed
Coastal States Energy Co., a subsidiary of Coastal States Gas Producing Co.	Commercial plant SNG from naphtha and other feedstocks	Capacity of the plant to be located near Corpus Christi will be 200 MMcfd from 40,000 Bpd of naphtha and other feedstocks. Estimated gas price is $1.10/Mcf. J. F. Pritchard has signed a letter of intent covering the design, engineering and construction of the plant. Plant will use CRG process. Project Cost estimated at $33 million.	Engineering and procurement phase with construction scheduled for completion in late 1974
Columbia LNG Corporation, a subsidiary of Columbia Gas System Inc.	Commercial plant SNG from LPG	Design capacity is 250 MMcfd from 70,000 Bpd of feedstock. Primary feedstock to be supplied by Dome Petroleum Corporation of Canada, with additional domestic U. S. sources. The British Gas Council CRG process is used. Contractor is Davy Powergas, Inc. *Project Cost estimated at $45 million.*	*Plant is in startup stage and is expected to be in-service operation by January, 1974*
Consumers Power Co.	Commercial plant SNG from LPG & natural gas liquids	Ultimate capacity is 200 MMcfd from 50,000 Bpd supplied by Dome Petroleum and Amoco Canada from Alberta. Estimated gas cost is $1.00 plus. Plant being built by Lummus Co. Estimated stream date *for ultimate capacity is by 2nd quarter 1974.* *Project Cost estimated at $155 million.*	*First half of ultimate capacity in operation September, 1973*
Continental Oil Co.	Commercial plants SNG from liquid hydrocarbons	Two plants. One will use 33,000 Bpd LPG; the other will use 27,200 Bpd naphtha. Plant locations in Northern Illinois. Northern Illinois Gas Co. has signed a letter of intent to purchase 125 MMcfd of gas over a 20-year period. Estimated completion date is 1975.	Planning

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Crown Central Petroleum Corp.	Commercial plant SNG and low sulfur fuel oil from crude oil	Products will be SNG and 0.3% sulfur fuel oil from 100,000 Bpd crude oil. Plant location is Maryland. Columbia Gas System will purchase 100 MMcfd at $1.1297/Mcf. *Construction scheduled to be completed in 1976.* Plant capacity is 100 MMcfd and the process used will be CRG. Project Cost estimated at $200 million.	Planned
El Paso Natural Gas Co.	Commercial Plant - SNG and low-sulfur fuel oil from crude oil	Capacity is 1125 MMcfd of SNG and 103,000 Bpd of low sulfur fuel oil from 300,000 Bpd of crude oil and 65,000 Bpd of crude condensate. Process configuration will consist of conventional refinery process units to extract naphtha from crude feedstocks and desulfurize residual fraction. Naphtha will be reformed to SNG by Lurgi process. Site is near Corpus Christi, Texas. Project Cost estimated at $750 million.	Planning
Felmont Oil Corp.	Commercial plant - SNG from naphtha	Capacity is 125 MMcfd from 28,000 Bpd of imported feed. Proposed plant location is Olean, N.Y., which is close to Felmont's wholly-owned Allegany State Park underground gas storage field. Plans call for running 10 to 12 Bcf/yr. of the SNG through this storage facility.	Suspended
Florida Gas Company, Texas Gas Transmission Corporation, The Charter Company	*Commercial plant SNG and low-sulfur fuel oil from crude oil*	*Capacity of this plant, to be located near Jacksonville, Florida, would be 400 MMcfd and 50,000 barrels of low-sulfur fuel oil per day from approximately 150,000 barrels of crude oil per day. The synthetic gas produced by the plant would be available to Florida Gas and Texas Gas for use in their pipeline systems.*	*Preliminary feasibility study being conducted*
GASCO (Hawaii)	Commercial plant SNG from naphtha	Plant capacity to be 16 MMcfd from 2,700 Bpd feed. Estimated SNG cost will be $1.57. Plant location is to be Barber Point, Hawaii. Ralph M. Parsons Co. is to be builder. Lurgi process is to be used. Project Cost $10-$13 million (60% for plant cost and 40% for pipeline.)	Operation planned for 1974
Howard Oil Refining Co.	Commercial plant - SNG from crude oil	Products will be SNG & low-sulfur residual from 150,000 Bpd feed. Crude oil will be imported. Plant location will be Philadelphia. Production slated for late 1973. Plant capacity is 177 MMcfd. MRG process to be used. Project Cost estimated at $180 million.	Feasibility studies by Procon completed
Hydrocarbon Research, Inc.	H-Gas Demonstration plant SNG from low-grade hydrocarbons	HRI has completed a pilot plant program with a 6-inch diameter reactor handling up to 15 Bpd of feed. HRI's next step is to build and operate a demonstration plant having a capacity of 5.6 MMcfd of SNG.	Active
Indiana Gas Co.	Commercial plant SNG from naphtha or propane	Plant to be located in Indiana. Plant capacity is 60 MMcfd.	Planning Negotiating for feedstocks
International Materials Corp.	Pilot plant - SNG from low-grade oils	The plant will use the SEGAS process which is now under development by International Materials Corp. The Burlington, Mass. plant will have a 1.2 MMcfd capacity.	Planning
JOC Oil U.S.A. Inc.	*Commercial plant SNG from naphtha*	*Capacity would be 125 MMcfd from 30,000 b/d of naphtha. The plant would be located near Burlington, N.J. J. F. Pritchard has completed an engineering-design study.*	*Planning*
Moore and McCormack Co.	Commercial plant SNG from light liquid hydrocarbons	Plant will be built by Moore and McCormack Co. in Berkeley County, S.C. A subsidiary Moore and McCormack Energy will operate the plant. The 30 MMcfd output of the plant will be sold to South Carolina Electric and Gas Company. Project Cost estimated at $10 million. Note: Previously listed South Carolina Electric and Gas Co. as owner.	Planning
New England Petroleum Corp.	Commercial plant - SNG and fuel oil from crude oil	Capacity will be 100 MMcfd SNG and 50,000 Bpd low-sulfur heavy fuel oil from 100,000 Bpd crude oil. Plant site at Oswego, N.Y. adjacent to Niagara-Mohawk Power Co. which will purchase all gas. Planned for completion by October, 1974. Project Cost SNG plant $28 million Crude oil plant $37 million Pipelines & Storage $15 million	Announced
Northern Illinois Gas Co.	Commercial plant SNG from liquid hydrocarbons	*Capacity will be 375 MMcfd of SNG from 85,000 bbl/day of naphtha by the CRG process.* Plant site is Minooka, Illinois. Gas will be sold in Illinois only. Bechtel is the builder. Project Cost estimated at $55 million.	Under construction with 1974 completion scheduled
Northwest Natural Gas Co.	Commercial plant SNG from light hydrocarbons or naphtha	Capacity is 100 MMcfd from naphtha delivered by tankers or Canadian light hydrocarbons delivered via pipeline (Blackfoot). Plant site is former oil gas plant, Portland, Oregon. Lurgi process selected. Fluor will do design and construction. Estimated gas cost $1.16-$1.20 per Mcf. The plant will use 24,000 Bpd of natural gas liquids. On line by November 1, 1974. Project Cost estimated at $25 million.	Under construction
Peoples Gas Light and Coke Co., a subsidiary of Peoples Gas Co.	Commercial plant SNG from petroleum liquids	Capacity will be 154 MMcfd from 33,000 Bpd of petroleum liquids. The plant site is Jackson Township, Illinois. M. W. Kellogg Co. is the builder. The CRG process will be used. Amoco Production and Union Oil of California will provide the feedstock. Completion is planned for the 1974-1975 heating season. Project Cost estimated at $57 million.	Under construction

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Phillips Petroleum Co.	Commercial plant SNG from light hydrocarbons	Capacity will be up to 67 MMcfd. Natural Gas Pipeline Co. of America has a contract to purchase the SNG. The plant site is at Phillips refinery in Borger, Texas. Process not announced, possibly will be the HOC Clean Fuels Refinery process developed by M. W. Kellogg and Phillips.	Awaiting FPC approval
Public Service Electric & Gas Co. (N.J.)	Commercial plants SNG from naphtha	Two plants will be built employing the CRG process; both plants are being designed and constructed by Foster Wheeler. The first plant of 20 MMcfd capacity is completed and in operation. Capacity of the second plant is 125 MMcfd from 25,000 Bpd of feed. Naphtha feedstock will be delivered to the plant which is adjacent to PSE&G's Linden power plant by pipeline. PSE&G will use 90% of the SNG with the remaining 10% to be purchased by Elizabethtown Gas Co. Plant has received approval for construction and operation from the N.J. Board of Public Utility Commissioners and is expected to be in service for winter of 1973-74. Project Cost estimated at $30 million.	First plant -in operation- March, 1973, Second plant nearing construction
San Diego Gas & Electric and Pacific Resources, Inc.	*Commercial plant SNG and low-sulfur fuel oil from crude oil*	*Plant would be a 100,000 b/d fuels refinery 30 miles north of San Diego. The throughput of crude would be divided 40,000 bbl for low-sulfur fuel oil, 30,000 bbl for distillate fuel oil and the remainder for naphtha and conversion to SNG. Ralph M. Parsons Co. has been named design engineer and prime contractor for the facility which will cost about $150 million. Construction scheduled to begin in late 1974, on stream by 1977.*	*Planning*
Southern Natural Gas Co.	Commercial plant SNG from liquid hydrocarbons	*Plant capacity will be 60 MMcfd from liquid hydrocarbons. Plant to be located in Escambia County, Alabama. The CRG process was used is preliminary cost estimates.* Project Cost estimated at $13.8 million.	Preliminary design work completed. FPC application filed in December, 1972.
South Jersey Energy Co., a subsidiary of South Jersey Industries, Inc.	Commercial plant SNG from naphtha	Plant capacity will be 125 MMcfd from 24,000 Bpd of naphtha. British Gas Council's CRG process will be used. The Lummus Co. is the engineering contractor. South Jersey Gas Co., another subsidiary, will purchase 20% of the output of the plant. The remaining capacity will be sold to other gas utilities in the N.J., Penn., Delaware and Maryland area. Scheduled to go on stream in 1974-1975 heating season. Plant site is Gloucester Co., N.J. A second 125 MMcfd train is planned. Project Cost estimated at $30 million.	Being delayed due to difficulty in obtaining feedstocks.
Tecon Gasification Co., a Texas Eastern Transmission Corp. subsidiary	Commercial plant SNG from naphtha	Capacity is 500 MMcfd from 110,000 Bpd feed. Japan Gasoline Co. MRG process will be used and Procon/UOP will design and build the plant. Feedstock will be 1/3 domestic, the rest foreign. The gas will be delivered to Texas Eastern's lines. Plant will be located on a 3,500-acre tract near Donaldsville, La. A similar plant that was to have been built at South Plainfield, N.J. has been suspended due to local opposition. Consolidated Natural Gas Co., which was a party to that Tecon project has withdrawn. Project Cost $175 million.	FPC dismissed application for lack of jurisdiction. *Order being appealed*
Tenneco Oil Co.	Commercial plant SNG from naphtha	No details available	Unknown
Transco Energy Co., a subsidiary of Transcontinental Pipe Line Corp.	Commercial plants SNG from light hydrocarbons, naphtha and crude oil	Project includes a 250 MMcfd SNG from naphtha and propane plant and a 460 MMcfd SNG from crude oil plant. Lurgi process will be used for both facilities. Naphtha facility to be located in Upper Chichester Township, Delaware County, Pennsylvania, and is scheduled to be on stream in Spring, 1975. The crude oil conversion facility is scheduled to be on stream in late 1976 and will be located in northeast North Carolina. Project Cost Naphtha conversion plant - $85 million Crude oil conversion plant - $300 million	*Postponed indefinitely due to unavailability of crude oil*
Trunkline Gas Co. Plant will be owned & operated by a wholly-owned subsidiary	Commercial plant SNG from naphtha	Capacity is 150 MMcfd from 30,000 Bpd feed. Naphtha will be imported to Houston & pipelined to plant site in Illinois. Fluor is the contractor. Plant site is Blue Mound, Illinois. Project Cost estimated to be $50-$60 million.	Planning
Tucson Gas and Electric Co., *Arizona Public Service Company, Southwest Gas Corporation and Southern Union Gas Company*	Commercial plant SNG from naphtha	Plant capacity is 100 MMcfd (up from 75 MMcfd). The Lurgi process will be used. The contractor is Fluor. Construction is expected to start February, 1974 with completion in early 1975. Project Cost Estimated at $30 million.	Design and Engineering
United Gas Pipeline Co.	Commercial plant - SNG and fuel oil from crude oil	The plant would use 150 MBpd of foreign crude to produce 340 MMcfd of SNG and 80 MBpd of low-sulfur fuel oil. Plant location is Pascogoula, Mississippi. Gas produced would supplement United's interstate gas transmission system. Project Cost estimated to exceed $250 million.	Planned Seeking feedstock supply

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Washington Gas Light Co.	Commercial plant SNG from naphtha	Plant capacity will be 50 MMcfd from 10,000 Bpd of naphtha which will be supplied by Atlantic Richfield. Plant location is in Prince William County, Va. five miles north of Quantico on the Potomac River where Arco has an existing dock. Construction to begin in mid-1973 and plant to be in operation in the spring of 1975. Project Cost estimated at $20 million.	Announced
Zapata Corporation	Commercial plant - SNG from crude oil	Capacity is 500 MMcfd from 100,000 Bpd of heavy Persian Gulf crude oil. Plant to be located on the Gulf coast.	Planning

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Italics denote changes since September 1973 issue

Colony Development Operation 30% ARCO (operator) 30% Sohio 20% TOSCO 20% Cleveland Cliffs	Proposed commercial project	ARCO & TOSCO currently engaged in final review of data in hopes of making a commercial decision in 1974. Sohio & Cleveland not participating in data review but retain interest in Colony. If commercial decision is reached, estimated production would be 46,000 Bpcd of fuel oil or two products: naphtha & a sulfur-free distillate. C. F. Braun & Co. has been hired for construction engineering & final cost estimates. *Recent announcements include: possibility of starting construction in Fall 1974; a proposed pipeline route from plant to southeast Utah; a request to build a road from Grand Valley, Colorado to Colony property on Parachute Creek.* Project Cost Over $50 million has been spent on technology and environmental studies since 1964. *Commercial plant would cost at least $250 million.*	ARCO & TOSCO still contemplating commercial decision *(see p. 2-25)*
Colorado, state of in cooperation with Dept. of the Interior, 3 Colorado counties and 17 industry participants	Oil Shale environmental studies Piceance Creek Basin	Studies concerning (1) water resources, (2) surface rehabilitation & revegetation, (3) environmental inventory & impact, and (4) regional development & land use planning are being conducted to better ascertain environmental effects of an oil shale industry in Colorado. Scheduled for completion by July 1974. Project Cost $735,000.	Active (see p. 2-26 of Sept. 1973 issue)
Paraho Development Corporation (Development Engineering, Inc.)	Paraho Oil Shale Development Program	DEI leased BuMines Anvil Points oil shale experimental facility near Rifle, Colorado for 5 years and will conduct a 30-month project to demonstrate their vertical kiln technology. Direct & indirect heating will be studied in a pilot retort (2-1/2 foot diameter) and a semi-works retort (8-1/2 foot diameter). *Fifteen companies have now joined the program, thus assuring the full 30-month program.* Project Cost $7.5 million.	*Retort construction to begin in early 1974 (see p. 2-23)*
Equity Oil Company and Atlantic Richfield Company	Equity BX Project In situ shale oil recovery	Field test of a 5-spot in situ shale oil recovery process. Hot methane gas injected into naturally-fractured shale formation in SW Piceance Creek Basin. Tests modified to investigate hot steam injection. Tests suspended in 1971.	Suspended
Institue of Gas Technology American Gas Association	Oil shale gasification pilot plant	IGT is designing a 1 ton/hour batch process (8-hour charge) pilot plant. Project Cost $300,000.	Active *(see p. 2-15)*
National Science Foundation & University of Southern California	Biochemical processing of oil shale	An 18-month investigation of the use of sulfur-oxidizing bacterium for releasing kerogen from oil shale. Details unknown. Project Cost $120,000 NSF grant.	Active but no public announcements
Occidental Petroleum Company	Experimental in situ recovery of oil shale	An Oxy subsidiary, Garrett Research & Development Co., has been conducting an in situ experiment on D. A. Shale fee lands near DeBeque, Colorado since February 1973. Oxy's process essentially creates an oil shale retort underground by opening a mine, then collapsing the mine roof with explosives. The rubble is then ignited and shale oil collected by a series of pipes laid on mine floor, then recovered at the surface thru a conventional well. Nuclear explosives are not contemplated. *Recent announcements indicate recovery of 25-30 barrels per day with a 50% yield which is not further defined.* Project Cost $1 million committed for a 3-year program.	Active *(see p. 2-23)*
Petrobras (Petroleo Brasiliero, S.A.)	Prototype plant	A 2000-Tpd Petrosix shale retorting facility is being operated at Sao Mateus do Sul, State of Parana, Brazil. Facility includes all necessary support operations including surface mine, crushing plant, retort, off-gas processing, power plant, worker housing, etc. Most recent report indicates operation at design capacity. Project Cost total expenditures in excess of $35 million.	Approaching continuous operation at design capacity (see p. 2-40 of the June 1973 issue)

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Shell Oil Company	Field testing In situ shale oil recovery	Shell Oil Company initiated an in situ field test on land leased from Marathon Oil Company located along Piceance Creek in Colorado in late 1970. Two wells were involved in the test program. Project Cost unknown.	Suspended
Sohio Petroleum Company	Proposed commercial facility	In a presentation to Utah Board of Water Resources, Sohio stated it plans to start engineering design in 1975 for a commercial plant to be on-stream in 1978. Plant would be located in Uintah County, Utah. Project Cost not estimated.	No firm public announcement
Stanford Research Institute	Lurgi process retorting experiment	SRI seeking industry support for proposed 2000 T/D Lurgi retorting campaign to be conducted near Grand Valley, Colorado. Three-year program. Project Cost $16 million.	Proposal stage. (See March 1972 issue, p. 2-37)
Superior Oil Company	Feasibility studies of possible commercial plant. Experimental mine	Superior conducting studies on development of oil shale, dawsonite, and nacholite which occur on fee lands west of Meeker, Colorado. Lower zone shale would be developed by underground mining. Superior announced in June 1973 they would drive an experimental mine beneath leached zone in their fee property at northern edge of Piceance Basin. Superior still awaiting decision on land exchange with Dept. of the Interior. Project Cost no announcements.	No recent announcements (See p. 2-19, Sept. 1973 issue)
The Oil Shale Corporation (Tosco)	Direct gasification of oil shale	At Tosco's Research Center at Rocky Flats near Denver, experimental studies have commenced on the direct gasification of oil shale to produce an intermediate Btu gas suitable for conversion to pipeline quality gas. Project Cost unknown.	Project recently initiated
Union Oil Company	Continuing development of shale retorting processes	Work has continued quietly on further development of the Union oil "rock pump" shale retorting process and on Lurgi process retorting.	No recent announcements
U.S. Department of the Interior	Prototype Oil Shale Leasing Program	*Decision announced on Nov. 28, 1973 to proceed with leasing program. First lease sale (Tract C-a) scheduled for Jan. 8, 1974 in Denver. Sealed bonus bidding. Environmental lawsuit to stop first lease sale still considered a possibility. Numerous adverse comments by environmental groups were received by Interior in late Oct. and early Nov. Public reaction to announcement has otherwise been most favorable in Colorado, Wyoming and Utah.*	*See p. 2-28)*

Synthetic Fuels From Oil Sands

Italics denote changes since September 1973 issue

Great Canadian Oil Sands, Ltd. owned 97% by Sun Oil Co.--3% is publicly held	Commercial plant	Plant has been in operation since Sept. 1967. Energy Resources Conservation Board approval authorizes annual production equivalent of 45,000 Bpcd. Product is 38-40 gravity synthetic crude blended from gas oil, naphtha and kerosene fractions from Unifining of delayed coker distillate. Coker bottoms used as power plant feed. Mining by bucket wheel excavators. *Alberta ERCB recommended Approval of Application to increase production allowable to 65,000 BPCD in report released Nov., 1973.*	Operating *(See page 3-24)*
Imperial Oil, Ltd.	Experimental in situ recovery project	Imperial has been conducting steam stimulation recovery tests in Cold Lake heavy oil deposit since 1971 under experimental Approval No. 1503 issued by Alberta ERCB. Application to ERCB to produce 1500 to 4000 BPCD as experimental production application (details confidential). Imperial has sold data and ongoing program monitoring rights to 5 companies	Active (See September 1973 issue, p. 3-22 *and p.3-11 this issue)*
Muskeg Oil Company, wholly-owned subsidiary of AMOCO Canada, Ltd.	Experimental in situ recovery project	This rather extensive field project has been underway since 1958 under authority of Experimental Project Permit Approval No. 1195. Location is Section 27-85-8W4M. Application submitted in October 1968 seeking provincial authority to produce 15 million barrels of crude bitumen at rates up to 8000 Bpd. This planned sub-commercial in situ project was to fracture the formation by the patented Hydra-Frac technique and follow up with a combination forward combustion-water flood procedure known as the COFCAW process. AMOCO owns patent rights to both processes. Application was withdrawn by Muskeg in 1969 and formally cancelled in April 1970. Field work was discontinued until 1971.	Reactivated in 1971 with 10-acre, 9-spot well pattern (See March 1969 issue, p. 2-1 and June 1971 issue, p. 2-24)
Shell Canada, Ltd., & Shell Explorer Limited	Commercial plant	Application to ERCB announced in early August 1973 asks permission to produce 100,000 Bpcd from Bit. Sands Lease No. 13 by surface mining. Shell estimates recoverable reserves on Lease No. 13 total 3 billion barrels. *Pending Provincial approval, construction will commence 1976; production, 1980.* Project Cost *$710 million.*	*Application heard by ERCB in October, 1973 (See p. 3-11)*

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Shell Canada, Ltd.	In situ recovery test	A steam injection, in situ recovery test conducted this year in Peace River oil sands area *on experimental permit (Approval 1904) issued by ERCB.* Test will continue into 1974 and if initial results are favorable, a pilot plant will be built. Decision to proceed with commercial production will be based on pilot results. Full scale production would be achieved in 1983 barring unforeseen delays. Project Cost in situ recovery test, $1.5 million full scale production, $0.5 to $1.0 billion.	*Active (See page 3-11)*
Syncrude Canada, Ltd., a Canadian nonprofit corporation owned jointly by Atlantic Richfield Canada, Ltd. (30%), Canada-Cities Service Ltd. (30%), Imperial Oil, Ltd. (30%) and Gulf Oil Canada, Ltd. (10%)	Commercial plant	Commercial facility to be located on Bit. Sands Lease No. 17. Allowable production is 125,000 Bpcd of 30+ gravity syncrude and 5479 Bpcd of residual oil. Mining by draglines, hot water process for bitumen recovery. Conceptual design of extraction plant, road, railway, and water supply systems underway. Application to ERCB asks for delay in start-up to mid-1977 instead of 1976. Initial production expected to be 104,500 Bpcd. *ERCB has recommended approval of application. Letter of intent on royalty and Canadian participation terms issued by Province.* Project Cost estimated at $744 million.	Conceptual design underway. *(See pp. 3-18 and 3-22)*
Texaco Exploration Canda, Ltd.	Experimental in situ recovery project	Texaco Exploration was issued experimental permit No. 1769 by the Energy Resources Conservation Board of Alberta, Canada in June 1972 to conduct a pilot recovery project on Bituminous Sands lease No. 51 held by that company in the Athabasca deposit area of the province. Overburden ratios in the area of the project suggest some form of in situ program. Project Cost $3 million.	Project commenced in June 1972 (See Sept. 1972 issue, p. 3-28)

Synthetic Fuels From Coal

Italics denote changes since September 1973 issue

Bureau of Mines	Synthane Project Pilot Plant SNG from coal	Capacity to be over 1 MMcfd of gas from 70 Tpd of coal. The gasifier is a fluid bed reactor with high methane make. Plant site is Bruceton, Pa. Lummus Co. has completed plant design. Rust Engineering has been awarded a $9,650,000 contract for construction of the plant.	Under construction, completion date is August, 1974
Bureau of Mines and Union Pacific Railroad	Underground Coal Gasification Project	Air acceptance tests at the Hanna, Wyo. site indicate that the coal bed is tight insofar as in situ gasification is concerned. Air acceptance increased five-fold as a result of hydraulic fracturing. A forward-burning gasification test is being conducted. *Gas is being produced at a steady rate of 2.5 million scf per day. The gas has a heating value of 140-150 Btu/scf and contains about 15% methane, 10% carbon monoxide, 15% hydrogen and 15% carbon dioxide. Oxygen instead of air is to be injected in future tests.*	Active (See page 4-14 of June issue for a description of overall project)
Catalysts & Chemicals Inc.	Pilot plant methanation of coal gas	The pilot plant consists of three methanation reactors to be used for proving a catalyst and designing a methanation process for use in commercial coal gasification plants. Plant capacity is 150 Mcfd of pipeline gas. The plant is located in Louisville, Ky. Pilot plant program is scheduled to require 12 to 24 mo. to complete.	Operational
COGAS Development Co. (CDC) joint venture of FMC Corp., Panhandle Eastern Pipe Line, Tennessee Gas Pipeline, Consolidated Natural Gas, Republic Steel, and Rocky Mountain Energy	COGAS Project Pilot Plants - SNG and synthetic crude oil	Pilot plant facilities are under construction at Princeton, N.J. and at Leatherhead, England. The Bechtel Corp. will assist in evaluating comparative process alternatives, designing and erecting a pilot plant, making a preliminary commercial plant design and making economic evaluation for facilities at Princeton, N.J. The pilot plant at Leatherhead will be constructed and operated by the British Coal Utilization Research Association and the National Research Development Corp. This pilot plant will have a capacity of 53 tons/day of char feed to produce 2.5 MMcfd of synthesis gas. Operating pressure will be 15-50 psig. Project Cost pilot plant phase estimated at $7 million.	Plant under construction, operation scheduled for late 1973
Colorado Interstate Gas Co.	Pilot plant research SNG from coal Commercial plant	Process development being done by Garrett Lab., a subsidiary of Occidental Petroleum Corp. Process carbonizes coal at relatively low pressure; char is by-product. Site of the pilot plant is LaVerne, Calif. CIG has option on large block of coal land in Montana from Westmoreland Resources. Project Cost cost of current research estimated at $0.5 million.	Active (See page 4-30 of June 1973 issue)

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Commonwealth Edison Co.	Demonstration plant Fuel gas from coal	Commonwealth would help finance, build & operate a plant in the Chicago area near an existing power plant. Lurgi gasifier would be used to make 180-Btu/cf gas. Ash and sulfur would be removed and clean gas used in existing boiler. Product tars would be used to briquet coal fines. Could be in operation by 1975. Project Cost - estimated at \$23.5 million.	Proposed
Conoco Methanation Co., a wholly-owned subsidiary of Continental Oil Co.	Demonstration plant - methanation of coal gas	Plant methanates purified gas from Lurgi gasifier and produces 2.6 MMcfd of methane. Site is adjacent to Scottish Gas Board's Lurgi gasifiers at Westfield, Scotland. Conoco designed the facilities, Woodall-Duckham constructed the plant. British Gas Council is acting as a consultant. There are 15 companies participating with Conoco. *Plant is operating and has successfully produced high methane gas (95%) at rates of 85-90 percent of designed capacity. One-year test program is planned.* Project Cost estimated at \$5 million.	*Operational (See page 4-38)*
Edison Electric Institute and the Southern Company	Pilot plant Solvent refining of coal	The plant has been built on the site of Southern Electric Generating Company's E. C. Gaston Steam Plant located near Wilsonville, Ala. The plant has been designed and constructed by Catalytic, Inc. Catalytic will also operate the plant. Plant capacity will be six tons of coal per day to produce a "clean fuel" containing 90% of the carbon in the original coal. The process dissolves coal under pressure with a small quantity of hydrogen, which reduces the ash content to about 0.1%. The sulfur content may be reduced to as low as 0.3%. Project Cost - EEI has pledged \$4 million to the project and Southern Company's affiliates, also EEI members, have pledged \$2 million in support.	*Construction was completed during August 1973. The plant is now undergoing pre-operational testing and should commence test runs in late 1973 or early 1974.*
El Paso Natural Gas Co.	Commercial plant - SNG from coal	Capacity will be *288 MMcfd*. Lurgi gasifiers will be used. Stearns-Roger Corporation has engineering contract and is working with German Lurgi. Plant site is adjacent to coal lease held by El Paso on Navajo Indian Reservation in northwestern New Mexico. El Paso plans to operate a commercial size development gasifier by late 1974. *Project Cost - plant cost now estimated at \$491 million* *- mine cost estimated at \$113 million*	Design and evaluation underway *FPC Application Supplemented Oct. 10, 1973 (see page 4-33 of this issue and page 4-28 of the March issue)*
Environmental Protection Agency - sponsor Applied Technology Corporation contractor	ATGAS Project - Development of design criteria	EPA contract provides for work on design criteria for a 50-100 MW power generating plant utilizing a low-Btu gas produced by the ATGAS process. Process employs a unique molten-iron gasification technique to gasify all types of coal with steam and oxygen at low pressures. Project Cost EPA contract for \$1,719,350.	Active
Environmental Protection Agency sponsor *J. F. Pritchard & Company contractor*	*Engineering evaluation*	*Engineering evaluation of the SO_2 free, two-stage coal combustion process developed by Applied Technology Corporation (called the ATGAS Process) applicable to a 1000 MW power generating plant.* *Project Cost - EPA contract is for \$140,000.*	*Active*
Exxon Corporation	*Research and pilot plant operation*	*Exxon is initiating a two-stage program to develop both a coal gasification process and a coal liquefaction process. The first stage will involve further research, and design of two large scale pilot plants. If successful, a second stage will be undertaken involving the construction and operation of the pilot plants to be located at Exxon's Baytown, Texas refinery. Capacities of the gasification and liquefaction pilot plants will be 500 and 300 tons per day, respectively.* *Project Cost First stage \$10 million.* *Second stage \$145 million.*	*First stage of gasification experiments to be completed during 1974. First stage of liquefaction experiments to be completed during 1976 (See page 4-39)*
Exxon Corporation	*Commercial plant*	*Carter Oil, an affiliate of Exxon Corp., is studying the possibility of constructing a coal gasification plant in northern Wyoming. Carter has state and Federal leases in both Sheridan and Campbell counties; however, the probable location of the plant will be near Gillette, Wyo. in Campbell County. Also, Carter has an industrial water contract for 50,000 AFY from the Yellowtail Unit on the Big Horn River.* *Project Cost \$400-\$500 million for commercial plant.*	*Feasibility study initiated in late 1973 will take 18 months. (See page 4-39)*
General Electric Co.	Pilot plant - SNG from caking coals now, synthesis gas later	Work to date has been done at G.E.'s Research and Development Center in Schenectady, New York. A "feasibility" unit has been built which operates at one atmosphere pressure and consumes about a quarter of a ton of coal per day. Successful runs, using low-grade coals from Illinois and Missouri have been made. The unit is a fixed bed reactor which uses a unique extrusion method of injecting coal into the gasifier. Within a year a 20-atmosphere demonstration gasifier of a half a ton of coal per hour capacity is to be built. Long-term plans call for the building of a prototype plant with a full-scale gasifier; also a liquid membrane scrubber system for sulfur removal will be studied.	Operating

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Hydrocarbon Research Inc. operator, Financial sponsors - Ashland Oil, Atlantic Richfield, Esso Research and Engineering, and Standard Oil Co. (Indiana)	H-Coal Project Pilot plant low-sulfur fuel oil	Testing of H-Coal process is being done in a pilot plant at Trenton, N.J. Process uses an ebulated catalyst to liquefy coal under hydrogen pressure in the presence of a recycle oil. Product ranges from low-sulfur fuel oil to high quality gasoline and naphtha. A prototype plant is currently being designed and construction will start January 1, 1974.	Active
Institute of Gas Technology and Ralph M. Parsons Co.	U-GAS Project Pilot plant - low Btu gas from coal	Parsons will produce engineering-design services for a demonstration gasifier to fuel a 50-100 MW power generation plant. Industry and government financing is being sought. Process reacts crushed coal with air and steam in a single-stage fluidized-bed gasifier at pressure of about 300 psig. Produced gas has a heating value of 140 Btu/cf. Sulfur and particulates are removed from the raw gas in a high temperature cleanup system. No site has yet been selected.	Active
Illinois Group 7 companies	Commercial plant - SNG from coal	Nothing definite on plans for a commercial scale gasification plant.	Investigating feasibility.
Island Creek Coal Co. and Garrett Laboratories, both subsidiaries of Occidental Petroleum Corp.	Pilot plant - conversion of coal to fuel oil	The pilot plant, located at LaVerne, Calif., will use a rapid pyrolysis process. Garrett has also been operating a pilot plant to convert 4 tons per day of municipal solid wastes to low-sulfur oil, char and gas using the flash pyrolysis process. Planning is underway for construction of a 200 Tpd demonstration facility to further evaluate the GR&D Process. Sponsors are being sought for this next step which will require about 4 yrs. and funding of approximately $6 million.	Active
Michigan Wisconsin Pipe Line Co. a wholly-owned subsidiary of American Natural Gas Co.	Commercial plants	Michigan Wisconsin has a 20 year option on about 3 billion tons of lignite under lease from the Coteau Properties Co., a subsidiary of The North American Coal Corp. The lignite reserves are located in Mercer, Oliver, McLean, Dunn, Stark and Billings counties of west central North Dakota. *Michigan Wisconsin has not committed to a construction schedule, but is actively studying the feasibility of constructing an initial 250 MMcfd Lurgi plant with a 1979-80 target completion date. North American will do the mining.*	Planning
Natural Gas Pipeline Company of American, a wholly-owned subsidiary of the Peoples Gas Company	*Dunn Center Coal Gasification Project Commercial plants*	*On January 25, 1973 NGPL and the Nokota Company (formerly Star Drilling, Inc.) entered into a twenty year leasehold encompassing approximately 110,000 acres in central Dunn County, N. D. Under terms of the agreement, NGPL has exclusive rights to proven lignite reserves of 2.1 billion tons within the lease area. First 250 MMcfd plant utilizing Lurgi technology currently envisioned to be operating by 1980 with successive plants following at three year intervals. Reserves are adequate for up to eight plants.*	*Planning*
Northern Natural Gas Co. and Cities Service Gas Co.	Commercial plants	Joint pursuit of coal gasification in Powder River Basin of Montana-Wyoming for gasification to 1,000 MMcfd SG in four plants of 250 MMcfd capacity. Peabody Coal Co. has dedicated 500 million tons of coal from the Northern Cheyenne Indian Reservation (Montana) to the project.	Under study (See page 4-30 of the June 1973 issue)
Office of Coal Research and American Gas Association	Lurgi process development	Development to modify the Lurgi reactor that will enable it to handle coking and swelling American coals. Tests will be made in Scottish Gas Board's Lurgi plant at Westfield, Scotland. Lurgi was responsible for internal reactor modification while Woodhall-Duckham was contracted to make the necessary ancillary system modifications to isolate the single gasifier unit. Technological guidance will be provided by British Gas and Lurgi throughout the program. Some 20,000 tons of U.S. coals have been shipped to Scotland which include: Illinois No. 5, Illinois No. 6, Pittsburgh No. 8 and Montana Rosebud coals.	*Tests underway* (See page 4-18 of September issue)
Office of Coal Research and American Gas Assoc. - sponsors, Battelle Columbus - contractor	Process development unit SNG from pulverized coal	A process development unit will be constructed at West Jefferson, Ohio for development of an ash agglomerating process for producing synthesis gas from a pulverized coal feed. Heat is supplied by circulation of hot, partially burned char from a burner vessel into the gasifier. Capacity of the PDU will be approximately 800 Mcfd of synthesis gas. Project Cost Battelle was awarded a $4.1 million, 30-month contract to operate the PDU on March 23, 1973 (Two-thirds by OCR, one-third by AGA).	Scheduled construction completion is Jan., 1974
Office of Coal Research and American Gas Assoc. sponsors, Bituminous Coal Research Inc. - contractor	BI - Gas Project Pilot plant - SNG from coal	The process developed by Bituminous Coal Research, Inc. reacts pulverized coal in a stream of oxygen and steam at high temperature and pressure to produce a gas interchangeable with natural gas. Stearns-Roger Inc., has been awarded the contract to design and build the pilot plant which will process 5 tons of coal per hour to produce 100 Mcfh of pipeline quality gas. Plant site is Homer City, Pa. Project Cost plant cost estimated at $18 million total cost estimated at $24 million	Under construction - scheduled for completion in July 1974

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Office of Coal Research and American Gas Assoc. - sponsors, Chem Systems - contractor	Process development unit - liquid phase methanation	A process development unit will be constructed by Demarkus for development of a liquid phase methanation process.	*PDU in design and construction phase*
Office of Coal Research and American Gas Assoc. - sponsors, Consolidation Coal Co. contractor	CO_2 Acceptor Project Pilot plant - SNG from coal	The plant located at Rapid City, S.D. is designed to produce 2 MMcfd of 375 Btu/scf gas from 40 tons of lignite and 3 tons of dolomite per day. In the CO_2 Acceptor Process developed by Consol, ground lignite is fed into a gasifier under pressure of 150 to 300 psi and heated to 1560°F by steam. Dolomite, pre-heated to 1900°F, is introduced into the gasifier and by chemical reaction, absorbs the carbon dioxide present in the gasifier releasing additional heat. Only methanation is then required to make pipeline quality gas. Project Cost - $9.3 million for construction and an estimated $5 million annually for operation.	Completing shakedown Construction of methanation unit is scheduled for Dec. 1973
Office of Coal Research - sponsor, Combustion Engineering, Inc., also participating are C. E. Lummus Division and Consolidated Edison	Process development - low Btu gas from coal	This program is to develop an entrained coal gasification process. Phase I consists of various system and component design studies which will provide the basis for selection of the entrainment type gasifier system to be done by C. E. Combustion Division. C. E. Lummus will design the cleanup phase of the process with Consolidated Edison evaluating the optimum system for application of coal gasification to utility electric power generation. Project Cost - $226,270 for Phase I.	Active
Office of Coal Research - sponsor, FMC Corp. contractor	C.O.E.D. Project Pilot plant - liquid fuels from coal	Pilot plant, located at Princeton, N.J., has a capacity of 36 tons of coal per day yielding about 30 Bpd of refinery feedstock plus char. The process employs multiple fluidized beds. Plant has operated on Colorado and Wyoming coals and is currently using Illinois coal. More than 5,000 tons of coal have been processed since operations began. FMC Corp. has installed a $400,000 oil absorber system which is expected to enhance oil yield, permit coal solids recovered from the gas stream to be recycled back into the pyrolysis reactors and to reduce capital cost. Project Cost - pilot plant estimated at $4 million.	Operating
Office of Coal Research and American Gas Assoc. sponsors, Institute of Gas Technology contractor	HYGAS Project Pilot plant Hydrogasification	Pilot plant has a capacity of 1.5 MMcfd of pipeline-quality gas. Process involves making hydrogen from char and reacting the hydrogen at high temperatures and pressures with coal. Three alternate methods are available for producing the necessary process hydrogen. These are: the electrothermal, steam-oxygen, and steam-iron processes. The hydrogasification section has operated successfully for runs up to 100 hours in duration. IGT was awarded two contracts for developing the steam-iron and steam-oxygen processes which are effective until June 30, 1975. Project Cost total OCR/AGA commitment since 1964 has been $56.5 million - steam-oxygen development program - $16.5 million - steam-iron development program $18.2 million	Operational
Office of Coal Research sponsor, Pittsburg & Midway Coal Mining Co. - contractor	Solvent Refined Coal Project Pilot plant - demineralized, low-sulfur extract from coal	Stearns-Roger Inc. designed the plant which will be located at Fort Lewis, Wash. Rust Engineering has been awarded the contract for construction of the pilot plant. The plant will process 75 tons of coal daily and yield about 50 tons of extract. Developed by P&M through bench-scale work, the process extracts coal with a recycle solvent which is then removed leaving a pitch-like coal extract. Project Cost - $28 million contract to continue until 1976.	Construction scheduled for completion by the end of 1973
Office of Coal Research - sponsor, Pittsburg & Midway Coal Mining Co. contractor	Pilot plant low Btu gas from coal	An entrained coal gasifier will be built to utilize the BCR two-stage gasifier design. The experimental gasifier will be air-blown and will be capable of operation to a probable maximum pressure of 500 psi. Pressure range to be studied will be from 60 to 500 psi. Capacity of gasifier will be approximately 50 ton/hr. The work will be performed by a four-member team consisting of P&M and Foster Wheeler who will provide engineering services, United Aircraft Turbo Power and Marine Services who will provide turbine expertise, and a utility company to be named later.	Active
Office of Coal Research sponsor, University of North Dakota Engineering Experiment Station - contractor	Project Lignite PDU SNG and low-sulfur fuel oil from lignite	A process development unit of approximately 50 lb/hr. capacity will be used for the solvent refining of lignite. Data generated in autoclave experiments and bench-scale tests are being used to design the PDU. Project Cost - a five-year $3.4 million contract was awarded by OCR.	Under construction with operation set for early 1974
Office of Coal Research - sponsor, Westinghouse Electric Corp. - contractor	Research Project - Generation of electric power from coal	The 3-year contract provides for work on the development of magnetohydrodynamics (MHD), solid electrolyte fuel cells, and development of gas turbine-steam turbine power plants. High temperature, high pressure gas cleanup systems will be studied and evaluated, and the use of fuel cells for the production of hydrogen will be developed. An ancillary task includes development efforts on the transmission of large blocks of power for transcontinental distances in super-conductors. The work will be directly or indirectly related to conversion of coal to electricity. Project Cost - estimated $5.7 million.	Active

STATUS OF SYNFUELS PROJECTS

OWNERS & SPONSORS	PROJECT DESCRIPTION	DETAILS	STATUS
Office of Coal Research sponsor, Westinghouse Electric Corp. - contractor. Program involves six-member industry/Government team comprising OCR, Westinghouse, Public Service Indiana, Bechtel Corp., AMAX Coal Co. and Peabody Coal Co.	Process development plant low Btu gas from coal	The project will involve a six-phase development, initially a 1200/lb hr process development plant (PDP) supported by laboratory investigations to confirm operational data received from the PDP. The PDP phase will be followed by constructing and operating a 5-ton/hr. gasifier pilot plant. Upon successful operation of the 5 ton/hr pilot plant, a 50 ton/hr commercial generating pilot plant will be constructed to be operated by Public Service Indiana at their Dresser facility. Ten additional companies are participating in the funding. The process will provide a clean burning gas with a heating value of 120 to 160 Btu/scf. Project Cost - Total program estimated at $80 million. OCR has awarded to Westinghouse a $8.2 million contract for 70% of the initial R&D cost.	Construction of PDP unit is expected to be completed in early 1974
Oklahoma, State of	Study SNG from coal using nuclear heat	The process being studied involves solvent extraction of coal to obtain liquid extract which is then hydrogasified. Heat is supplied by hot helium from a high temperature, gas moderated nuclear reactor; overall thermal efficiency of 90% is claimed. Gulf General Atomics is prime contractor; Stone & Webster is participating. Work thus far consists of a literature search and preliminary economic study.	Active
Old Ben Coal Corporation, a subsidiary of Standard Oil Co. (Ohio)	*Demonstration plant Clean fuels from coal process*	*A plant capable of processing 900 tons of coal daily to produce clean liquid and solids fuels will be built to further test the process developed by Old Ben. No process details are now available. Old Ben is organizing a multi-company (15 or more) group to support the project. Consolidated Coal Co., Old Ben and Sohio are presently members of the group.* *Project Cost - estimated at $73 million.*	*Planning stage*
Panhandle Eastern Pipe Line Co. & Peabody Coal Co.	Commercial plant SNG for coal	Capacity will be 250 MMcfd. The Lurgi process coupled with advancements in methanation will probably be used. *Possible plant sites are being investigated in the eastern Wyoming area.* A commercial decision will be made by mid-1974. Peabody has set aside 665 million tons of coal reserves for the joint project. *Plant to be in operation during the 1978-80 period.*	Design and development program initiated
Stone & Webster Engineering Corp., and Gulf General Atomic Co.	*Research and development program*	*The joint program will be aimed at combining S&W's solution gasification process, which involves stepwise hydrogen conversion of coal, first to a liquid and then to a synthetic gas, with Gulf General's high-temperature-gas-cooled nuclear reactor, which would provide the heat for production of large amounts of hydrogen needed in the process. S&W will be project manager for the first phase which is a research and development program expected to last 2 years. The second phase will include the building and operation of a demonstration plant.* *Project Cost first phase estimated at $650,000.*	*Industry support being sought*
Texaco, Inc.	*Commercial plant Gasification or liquefaction of coal*	*On October 26, 1973 Texaco acquire rights to coal reserves estimated at 2 billion tons from Reynolds Metals Co. These reserves are located near Lake DeSmet in Wyoming on some 37,000 acres held by Reynolds. Under terms of the agreement, Texaco will also receive certain water rights to provide Texaco with water reserves to develop the coal reserves. Commercial plant employing either a gasification or liquefaction process could result.*	*Active (See page 4-39)*
Texas Eastern Transmission Corp. & Pacific Lighting Corp., Western Gasification Co. (WESCO) will own and operate plant	Commercial plant SNG from coal	Lurgi gasifiers will produce 250 MMcfd of pipeline quality gas; could be expanded to 1,000 MMcfd. Plant will be located adjacent to coal reserves owned by Utah International, Inc. on the Navajo Indian Reservation in Northwestern, N.M. Fluor Corp. did feasibility study and Battelle prepared the environmental impact statement. Approximately 9.6 million tons of coal per year, along with sufficient water rights to operate the plant will be purchased from Utah International under terms of a 25-year contract. Gas will be sold to Transwestern Pipeline on a cost of service basis. Plant Cost capital cost of plant estimated at $406 million.	*Amended application file 11/16/73* (See page 4-29 of March issue)
Texas Gas Transmission Corp.	Commercial plant SNG from coal	Texas Gas has acquired from Consolidation Coal Co. a half interest in an extensive block of coal reserves in the Illinois Basin area. The reserves are in 2 parcels. The first parcel will be held for a 10-yr. period in connection with a coal gasification project using technology now in the process of development. These reserves will be converted into approximately 3.5 trillion cubic feet of pipeline-quality synthetic gas. A primary site being considered is west of Evansville on the Ohio River where there is an abundant supply of the needed water and is in close proximity to Texas Gas's pipeline system. Construction is planned for late 1970's or early 1980's.	Planning
Transcontinental Gas Pipe Line Corporation	*Commercial plant SNG from coal*	*On October 2, 1973 Transco signed an option agreement with Stoltz, Wagner & Brown and Tipperary Corporation for joint development efforts of coal rights underlying more than 20,000 acres in the Powder River Basin of northeastern Wyoming. Under terms of the agreement Transco is authorized to evaluate the quantity and quality of the coal. Based on the evaluation Transco will determine the feasibility of a coal gasification project for producing pipeline quality gas.*	*Under evaluation (See page 4-39)*

COMING EVENTS

JANUARY 8, 1974, DENVER--Federal Oil Shale Lease Sale Tract C-a, at the Denver Bureau of Land Management Office. Other sales to be held as follow:

- February 12, 1974, Tract C-b at the Denver BLM Office.
- March 12, 1974, Tract U-a at the Salt Lake City BLM office.
- April 9, 1974, Tract U-b at the Salt Lake City BLM office.
- May 13, 1974, Tract W-a at the Cheyenne BLM office.
- June 11, 1974, Tract W-b at the Cheyenne BLM office.

JANUARY 16 and 17, 1974, NEW YORK--A two day briefing by the City College of New York research team working on improved techniques for gasifying coal. The group has been supported by a grant from the RANN Program of NSF. The briefing will review work in progress and describe the results obtained thus far under the following headings:

1. Introduction - The Coalplex
2. Coal Conversion
   - The reaction of coal with hydrogen under rapid heating - liquids production
   - Simulation of char gasification by steam in a fluid bed
3. Advanced Fluidization Techniques
   - Fast Fluid Bed
   - Agglomerating Fluid Beds
4. Hot Gas Cleaning
   - Panel Bed Filter
   - Sulfur Absorption by Solid Acceptors
5. Systems Studies
   - Combined Cycles
   - Primitive Coalplex
   - Air Storage
   - Energy Corridor

The registration fee is $30 and the deadline for receipt of registration is December 19, 1973. The registration fee should be sent to:

Robert A. Graff
School of Engineering
The City College of New York
City University of New York
140th Street & Convent Ave.
New York, New York 10031

FEBRUARY 25-26, 1974, DALLAS--1974 AIME Synthetic Hydrocarbon Conference to be held at the Fairmont Hotel in conjunction with the 103rd AIME Annual Meeting. Program not yet finalized, but will include sessions on the following topics:

1. Coal liquefaction
2. Coal gasification
3. Environmental impact analyses in the synthetic hydrocarbon industry
4. Water requirements of the synthetic hydrocarbon industry

MARCH 6-8, 1974, DALLAS--AGA/IGT Natural Gas Research and Technology Conference, Sheraton-Dallas Hotel. Program not available.

MARCH 11-15, 1974, TULSA--AIChE 76th National Meeting, Fairmont Mayo Hotel. Program not yet available.

MARCH 25-27, 1974, DENVER--NGPA Annual Meeting, Denver Hilton and Brown Palace Hotels. Program not yet available.

MARCH 31-APRIL 5, 1974, LOS ANGELES--American Chemical Society, 167th National Meeting.
Program includes:

April 2, General Session.

1. "Sulfur Problems in the Direct Catalytic Production of Methane from Coal-Steam Reactions," J. L. Cox, L. J. Sealock, Jr.
2. "Conversion of Solid Fuels to Low Btu Gas," T. E. Ban.
3. "Effect of Manganese Additives on NO-Emissions from a Small Laboratory Oil Burner," E. R. Altwicker, I. Broadsky, T. T. Shen.
4. "Laboratory Studies on the Effect of Coal Additives in the Synthane Gasifier," A. J. Forney, W. P. Haynes, S. J. Gasior, R. F. Kenny.
5. "Active Sites for Coal Hydrogenation," K. Matsuura, D. M. Bodily, W. H. Wiser.
6. "Dehydrogenation of Coal by Metal Salt Catalysts," D. M. Bodily, H. Lee, W. H. Wiser.

April 2, Symposium on "Solids Handling for Synthetic Fuels Production."

1. "Coping With Tar Sands -- The Major New Source of Synthetic Fuels," A. R. Allen, GCOS.
2. "Treatment of Tar Sand Tailings With Fly Ash," N. N. Bakhshi, University of Saskatchewan.
3. "From the Coal Mine to the Gasifier," L. M. Brennan, Peabody Coal Company.
4. "Feeding a Commercial Oil Shale Facility," E. R. Carnahan & T. A. Kauppila, Cleveland Cliffs Iron Co.
5. "Solids Feeding into Pressurized Systems," E. J. Ferretti, Rust Engineering Company.
6. "Problems Associated With Lignite Handling and Preparation for Gasification Plants," D. G. Keay & J. P. Matoney, Kaiser Engineers.
7. "Environmental Impacts, Efficiency and Cost for the Energy Supply System Associated With High Btu Coal Gasification," W. R. Menchen, Hittman Associates, Inc.
8. "Material Handling and Its Compatibility With Energy Needs," E. L. Mills, FMC Corp.
9. "Environmental Problems With Waste Handling and Disposal in Developing New Fuel Technologies," L. E. Moss, Sierra Club.
10. "Benefit/Cost Approach to Decision Making: The Dilemma with Coal Production," F. K. Schmidt-Bleek and J. R. Moore, University of Tennessee.

April 3, "Symposium on Low-Sulfur Fuels from Coal."

1. "Removal of Sulfur from Coal by Treatment with Hydrogen," J. H. Gary, R. M. Baldwin, C. Y. Bao, J. O. Golden, R. L. Bain.
2. "Evaluation of Catalysts for Hydrodesulfurization and Liquefaction of Coal," W. Kawa, S. Friedman, W. R. K. Wu, L. Frank, P. M. Yavorsky.
3. "Organic Sulfur Compounds in Coal Hydrogenation Products," S. Akhtar, A. G. Sharkey, J. Shultz, P. M. Yavorsky.
4. "Low Sulfur Fuels from COED Syncrude," M. I. Greene, L. J. Scotti, J. F. Jones.
5. "Coal Liquefaction in a Slurry System," S. A. Qader, G. Haider, W. H. Wiser.
6. "Solvent Refining of Coal," W. B. Harrison, E. L. Huffman.
7. "New Energy Sources -- Is R&D Enough?" R. J. Cameron.
8. "Clean-Char Process," K. A. Schowalter, E. F. Petras.
9. "An Improved Technique for the Hydrodesulfurization of Coal Chars," L. Robinson, N. W. Green.
10. "Chemical Desulfurization of Coal," E. P. Stambaugh.
11. "Chemical Desulfurization of Coal to Meet Pollution Control Standards," J. W. Hamersma, M. L. Kraft, W. P. Kendrick, R. A. Meyers.
12. "Plant Design of a Method for Chemical Desulfurization of Coal," L. Lorenzi, Jr., L. J. Van Nice, M. J. Santy, R. A. Meyers.
13. "Coal Desulfurization: Costs/Processes and Recommendations," J. C. Agarwal, R. A. Giberti, L. J. Petrovic.
14. "Coal Demineralization by Magnetic Forces," S. C. Trindade, J. B. Howard, H. H. Kolm, H. D. Hottel, G. J. Powers.

April 3, "Symposium on Shale Oil, Tar Sands, and Related Fuel Sources."

1. "Fracturing Oil Shale with Explosives for In Situ Recovery," J. S. Miller, R. T. Johansen.
2. "Pulsed NMR Examination of Oil Shales--Estimation of Potential Oil Yields," F. P. Miknis, A. W. Decora, G. L. Cook.
3. "Effects of Bioleaching on Oil Shale," C. Meyer, T. F. Yen.
4. "Investigation of the Hydrocarbon Structure of Kerogen from Oil Shale of the Green River Formation," J. J. Schmidt-Collerus, C. H. Prien.
5. "Effect of Hydrocarbon--Utilizing Microorganisms on Oil Shale Kerogen," J. E. Findley, M. D. Appleman, T. F. Yen.
6. "Polycondensed Aromatic Compounds (PCA) and Carcinogens in the Shale Ash of Carbonaceous Spent Shale from Retorting of Oil Shale," J. J. Schmidt-Collerus, F. Bonomo, C. H. Prien.

April 4, "Symposium on Shale Oil, Tar Sands and Related Fuel Sources," continued.

1. "Hydrogasification of Oil Shale," S. A. Weil, H. L. Feldkirchner, P. B. Tarman.
2. "A Comparison of Shale Oil Denitrification Reactions Over Co-Mo and Ni-W Catalysts," H. F. Silver, N. H. Wang, H. B. Jensen, R. E. Poulson.
3. "Production of Synthetic Crude from Crude Shale Oil Produced by In Situ Combustion Retorting," C. M. Frost, R. E. Poulson, H. B. Jensen.
4. "Stepwise Oxidation of Bioleached Oil Shale," D. K. Young, S. Shih, T. F. Yen.
5. "Characterization of Synthetic Crude from Crude Shale Oil Produced by In Situ Combustion Retorting," R. E. Poulson, C. M. Frost, H. B. Jensen.
6. "Retorting Indexes for Oil-Shale Pyrolyses from Ethylene-Ethane Ratios of Product Gases," I. A. Jacobson, Jr., A. W. Decora, G. L. Cook.
7. "The Oxidation of Bitumen in Relation to its Recovery from Tar Sand Formations," S. E. Moschopedis, J. E. Speight.
8. "Sulphur Compounds in Oils from the Western Canada Tar Belt," D. M. Clugston, A. E. George, D. S. Montgomery, G. T. Smiley, H. Sawatsky.
9. "Development of a Biochemical Desulfurization Procedure for Fuels," A. J. Davis, III, T. F. Yen.
10. "The Development of Communication Paths Within a Tar Sand Bed," D. A. Redford, P. F. Cotsworth.
11. "Characterization of a Utah Tar Sand Bitumen," J. W. Bunger.
12. "Solubility of Silica in Some Organic Sediment Systems," C. Meyer, T. F. Yen.

April 5, "Symposium on Shale Oil, Tar Sands and Related Fuel Sources." continued.

1. "Differences Among Ozocerites," R. F. Marschner, J. C. Winters.
2. "Characterization of Synthetic Liquid Fuels," R. G. Ruberto, D. M. Jewell, R. K. Jensen, D. C. Cronauer.
3. "The Chemical Modification of a Bitumen and its Non-Fuel Uses," S. E. Moschopedis, J. G. Speight.
4. "Correlation of Oil Shale Particle Size to Rate of Dissolution of Mineral Matrix," M. Moussavi, D. K. Young, T. F. Yen.
5. "Direct Zinc Chloride Hydrocarcking of Subbituminous Coal - Regeneration of Spent Melt," C. W. Zielke, W. A. Rosenhoover, E. Gorin.

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2. Carrigy, Maurice, "An Illustrated Tour of the Athabasca Oil Sands."
3. Deroo, G., "The Geochemistry of the McMurray Oil Sands of Alberta."
4. Ebanks, W. J. "Heavy-Crude Oil Bearing Sandstones of the Middle Pennsylvanian Cherokee Group, South East Kansas."
5. Farouq Ali, S. M., "Application of In Situ Methods of Oil Recovery From Tar Sands."
6. Gallup, W. B., "The Geologic History of McMurray Coldwater Deposition in the Athabasca Oil Sands Area."

*7. Govier, G. W., "Alberta Bituminous Sands In the Energy Supply Picture." (See p. 3-4)

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*14. Minken, D. F., "The Cold Lake Oil Sands: Geology and a Reserve Estimate." (See p. 3-3)

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2. Conference on Property and Mineral Rights.
3. Conference on the Future of Agriculture in Southwestern North Dakota.
4. Conference on Recreation and Tourism in Southwestern North Dakota.

Other Reports to be published soon:

5. Conference on Mining and Power Production.
6. Conference on Resources of Southwestern North Dakota.

Copies of reports are available from: Earl E. Stewart, Director, Little Missouri Grassland Study, University Station, Box 5673, North Dakota State University, Fargo, North Dakota 58102. (See p. 4-7)

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2. Brennan, Joseph, "The Washington Scene and Coal's Capital Demands."
3. Dixon, Bruce, "1973 - A Crossroads For Accounting Standards."
4. Holland, Robert, "Public Policy Issues in the Financing of New Energy Capacity."
5. Joseph, Mark, "Foreign Assistance for an Undeveloped Industry."

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*Reviewed in this issue

I
syn-fuels: general

REP. UDALL PREDICTS END OF FOSSIL ERA AROUND YEAR 2000

In June of this year Rep. Morris Udall directed his legislative staff to "develop a summary picture of America's current energy position, complete with the kind of technological description that the layman can be expected to understand." Udall recently released the results of that study in the form of a 19-page booklet entitled "America's Energy Potential," dated October 1973.

In transmitting the report to Rep. James A. Haley, Chairman of the House Committee on Interior and Insular Affairs, Udall stated his hope that "...it will prove to be a useful resource for the committee members and our colleagues in Congress." He continues by explaining that "An earnest attempt has been made to present a factual study, free of opinion and value judgement. The study was, however, premised on the author's (Udall's) firm belief that this country is in deep trouble on the energy front."

Rep. Udall's letter of transmittal also notes that his report "...confirms the existence of two crises. The first results from an inability to extract known resources at a sufficient rate, already made evident by the gasoline and heating oil shortages." No attempt is made to identify the factors contributing to this so-called inability, thus leaving the implication that a lack of technology is the culprit.

The second and longer term crisis, according to Rep. Udall, "...involves the ultimate exhaustion of our fossil fuel resources and can be expected to occur around the end of the century." But again, the facts to support this conclusion are not clearly identified in the report. In essence, the report appears to be a blueprint for accelerated development of solar energy and, to a much lesser extent, geothermal and nuclear energy, but at the total exclusion of further development of our fossil fuel resources.

One must, of course, agree with Rep. Udall that the United States is in a tight spot with respect to the availability of energy but we seriously question whether his report will be a "useful resource" to Congress or to the general public. In fact, Rep. Udall's contribution to contemporary energy literature seems to provide just enough misinformation to make the average, self-appointed energy specialist a little more dangerous.

Udall's study is comprised of a series of status reports on each of the following energy resources: oil & gas, coal, nuclear energy, solar energy, and geothermal energy. Summaries of each are presented following.

Oil & Gas

Two pages are devoted to a summary of the oil and gas situation. It is noted that 75 percent of our current energy needs come from oil and gas but that the prospects for these resources meeting anticipated future demand are not bright. Domestic oil production is predicted to peak at 12 million Bpd, while demand is expected to reach 30 million Bpd by 1985. Both Alaskan oil and shale oil are identified as being only modest contributions to our supply base. Secondary and tertiary recovery from existing reservoirs (from which present techniques are said to recover only 25 percent of the oil) is paid lip service, but the potential of OCS sources of oil and gas is not even mentioned.

Udall thus identifies imports as the only possibility for meeting the future demand for oil. He then discounts imports because the Middle East is the only source large enough to provide the needed production increases and the Arab nations will not likely permit this. He sees no alternative to oil and gas shortages in the next few years even if imports are available because of a lack of refinery capacity.

Udall concludes that long range projections for both oil and gas are not bright. He specifically cites the NPC reserve estimates of 200 billion barrels of oil and 1000 trillion cubic feet of natural gas. His conclusion seems to imply that since oil and gas reserves are not inexhaustible, we shouldn't spend any more time or money on developing them.

Coal

Slightly more than two pages are devoted to coal. Coal accounts for 18 percent of our energy use. Udall admits that reserves are adequate for the foreseeable future (seemingly a paradox to his earlier statement regarding the end of the fossil fuel era), but tnat our expanded use of coal is fraught with extraction and effluent problems.

Underground mining of coal results in acid drainoff, unstable waste piles and land subsidence; it is both unsafe and unhealthy. Strip mining is safer but affects a greater surface area, results in land slides, and destroys valuable grazing land and aquifers. Further it is doubtful that western coal lands can be properly reclaimed because of low rainfall. "While coal gasification and liquefaction are attractive possibilities," according to the report, "the immense amounts of water required would put further strain on the available (water) supply."

Environmental damage does not end with extraction of the coal. Sulfur emission from coal usage is a serious problem. Udall briefly discusses stack gas cleanup and other sulfur removal technology but doesn't seem to have much confidence that success will be achieved in either area.

Solvent refining of coal is mentioned, with the only conclusion being that, "If success is achieved at a reasonable cost, solvent refined coal will reduce both sulfur dioxide and particulate pollution to a low level."

The status of tehcnology for both coal gasification and liquefaction are discussed, with gasification technology being identified as the more advanced. Even so, commercial gasification plants are not expected until 1985. Lurgi is identified as the only commercially feasible technology but is restricted to the use of low-caking coals according to the report.

Nationwide coal reserves are said to be plentiful, but only about 150 billion tons are currently available because much of the multi-trillion ton reserve is too deep for economical recovery. It is thus concluded that coal will not supply significant amounts of gas or oil until the 1990's; burning coal for power generation is ignored.

Requirements for the first 250-MMcfd gasification plant, according to the report, are seven million tons of coal and 30,000 acre-feet of water annually. Each plant of this size is expected to cost about $500 million. "To replace our present use of natural gas with gas from coal," the report notes, "would require 250 such plants, and a capital investment of $125 billion. Gas from such plants would carry a high cost, several times that of new natural gas, and it might be difficult to raise the necessary capital."

Finally, the report explains that water requirements may limit the final (coal) production rate. Further, it points out that the problems of reclaiming mined lands will have to be addressed before the true costs of developing Western coal resources can be fully assessed.

Again, the implication seems to be that if coal cannot satisfy our total energy requirement, then we should avoid wasting any more time or money on it.

Nuclear Energy

Nuclear power is described in Udall's report as one of the most troublesome and promising new energy sources. The report discounts coal, oil, and gas as viable sources of fuel to meet our future electric power requirements because of resource limitations and environmental problems. Hydroelectric power is similarly discounted on the basis, and rightly so, that acceptable sites are no longer available.

It is then noted that, "If we accept the option of nuclear power, much of the pollution of fossil fuels can be avoided, but other factors must be considered. Since the energy available from nuclear sources is probably ample," the report continues, "the major concern over the coming decades will center on minimizing the environmental impact and avoiding the safety hazards associated with its use. Specifically, the report explains, "the following questions need to be asked and answered before full development of nuclear energy can proceed: (a) what type of burner reactor is best; (b) whether a breeder is necessary and, if so, what type should be developed; and (c) how can the hazards of thermal pollution, reactor accidents and disposal of radioactive wastes be reduced to an acceptable minimum?"

The remainder of the nuclear section of the report concentrates on reviews of reactor technology, enrichment capacity, waste disposal problems and fusion.

Most nuclear power is currently generated by light water reactors (LWR), but they are less efficient and require twice as much fuel as high temperature gas-cooled reactors (HTGR). The disadvantage of HTGR's is that they are less advanced than LWR's since none are operating commercially yet and since HTGR's have received less funding in the past. At any rate, Udall's report places no great emphasis on the future of either LWR's or HTGR's.

The report's outlook for the liquid metal fast breeder reactor (LMFBR) is even less optimistic. In fact, the report's discussion of breeder reactor technology begins on a negative note by stating, "In spite of the considerable supplies of U^{235}, significant support is being devoted throughout the world to development of a fast breeder reactor." This comment appears to imply that "why bother with breeder reactors since LWR and HTGR technology is well-enough advanced and we have plenty of U^{235} anyhow." It appears to be a feeling based more on a fear of the unknown than on fact.

Nevertheless the potential of the LMFBR is downplayed in favor of both gas-cooled FBR's and molten salt FBR's. The report laments the fact that so little financial support is provided for gas-cooled or molten salt breeder reactors.

As it turns out, Udall's report is especially optimistic about the future of the light water breeder reactor. "By changing the core design of an ordinary pressurized water reactor," the report notes, "it may be possible to achieve a fissil inventory ratio (FIR) of 1.01 or better. Although the doubling time of this light water breeder reactor would be very long, it would not require further U^{235} after the initial fuel supply. Further, thorium would be the fertile material, which is more abundant than uranium...An FIR of greater than one, even if it produces no excess fuel, would imply sufficient energy reserves for thousands of years at the present rate of use."

Uranium enrichment capacity is cited as a problem. If nuclear power output is to be expanded, additional enrichment capacity will be needed in the early 1980's. Since it may take six or seven years to build an enrichment plant, the decision must be made soon to build new plants. The question is, "what type of enrichment plant should be built and who should build it?" The report explains that the AEC would like for private industry to take the responsibility, but acknowledges that industry must first consider it a profitable venture.

But these are not the only problems with enrichment plants. As the report points out, gas diffusion requires an enormous supply of energy. The gas centrifuge enrichment process is more energy efficient, but is not yet proven. The report concludes that since either type of plant would require a capital investment of several billion dollars, it is likely that only the Federal government would be willing to accept the risk involved.

The advantages of nuclear energy as compared with fossil fuel energy are said to be the availability and low cost of fuel and the absence of chemical pollutants. High capital costs, according to the report, are more than offset by these factors.

Notwithstanding the report's encouraging statements about the potential of nuclear energy, there is no positive endorsement of continued nuclear development.

Geothermal Energy

Geothermal energy is discussed amid a general note of pessimisim. Although it is noted that geothermal resources have the potential for all our energy needs for centuries, the environmental problems, including noise, and the technological problems are serious. Capital costs are not estimated. The entire discussion of geothermal energy is interspressed with if's, maybe's and hopefully's, leaving the reader less than enthusiastic.

Solar Energy

The true purpose of Rep. Udall's report becomes clear upon reading the section dealing with solar energy. Many of the reasons for discounting fossil, nuclear and geothermal energy as long-term contributions to our energy mix are cited to promote development of solar energy. It appears that, in Rep. Udall's view, the lack of a proven and economical solar technology is no serious deterrent to its use. The following excerpts will serve to illustrate that point.

"Its potential long underrated, solar energy is quickly gaining advocates in the scientific community. It is both a clean and renewable source with a potential for hundreds of times our present requirements...Direct use of solar energy may have immediate application for heating and cooling of residential and commercial buildings. Since such needs currently consume more than 20 percent of our total energy requirements, success in this area would eventually make a substantial contribution toward alleviating the energy crisis...Although the capital costs (of small-scale applications) would be high, the same collector and storage unit would be used for all three applications (hot water, space heating and space cooling). Estimated life cycle costs would then be comparable to present fuel costs in much of the country, and more favorable to the extent that fuel costs rise in the future."

In all fairness, the report does recognize the technological problems associated with solar applications but solutions are made to sound relatively simple. With respect to small-scale applications, as mentioned above, the report states, "Significantly, not much technological development is needed to achieve such advantages, but it would be useful to start pilot projects to improve the design, efficiency and acceptability of such systems."

The winds, which are powered by solar energy, are said to contain energy roughly comparable to our present energy consumption. "However," the report notes, "this is spread so thinly that it is questionable that significant production of energy can ever be obtained. In addition, the source is intermittent and storage or backup systems are required for realiability. Still, such systems could be important for special localized situations."

Taking advantage of thermal gradients in the ocean are cited as another promising solar application. Thermal differentials would power a low-pressure turbine, using a secondary working fluid such as ammonia. Since such plants would be located far from land, the electricity would be used to electrolyze seawater to produce hydrogen that could then be pipelined to shore. Hydrogen would then be burned like natural gas. Almost as an afterthought, the report notes that "Large-scale use of hydrogen would require some technological adjustments, such as modified burners and a new pipeline system," since, "present pipelines would suffer embrittlement if used for hydrogen."

The report continues to explain that, "municipal or agricultural waste materials can be converted to methane gas or even oil by bio-conversion using solar radiation to supply the necessary warmth...the total energy potential would be small, probably not more than a few percent of our projected usage, but is considered sufficient to warrant development."

The outlook for solar energy is given as follows:

> "Although costs are likely to be high, the clean, renewable and abundant nature of solar energy will provide strong incentive for extensive utilization in the future."
>
> "Small-scale solar collectors are likely to become available soon, but near term

widespread use is unlikely since present buildings already have installed heating and cooling capacity, and would require major modifications to switch to solar sources. With sufficient support, however, a significant fraction of new construction may utilize solar energy for hot water and space heating and cooling requirements by the end of the century.

"Solar central power stations are unlikely to contribute significantly to our electric power capacity until competing fuel costs rise substantially, or environmental considerations restrict construction of alternate sources. At that time, photothermal solar power could be developed to meet a substantial portion of our electrical requirements. Proponents of solar power maintain that funding and action are needed now to obtain necessary data and experience so that full scale construction can begin as economic considerations permit.

"As natural gas reserves become exhausted it is possible that the United States may shift to a hydrogen economy with the hydrogen being obtained from electrolysis of water using electric power. Hydrogen can be shipped by an appropriate pipeline system and can be used by industry in place of natural gas, although it would not work for present residential users. The intermittent nature of direct solar conversion for wind power or the distant nature of ocean thermal power would then not be a disadvantage since energy could be shipped or stored in the form of hydrogen gas. Such a development might occur by the end of the century."

<u>Summary</u>

As stated at the outset, Rep. Udall's report is not a particularly useful resource for Congress. It provides far too little information on which sound legislative decisions can be based.

Notwithstanding Rep. Udall's transmittal letter, the report is biased toward solar energy. For example, the contention that conversion of municipal and agricultural wastes would provide only a few percent of our energy needs but is still sufficient to warrant development does not ring true. Earlier, the report notes that shale oil production could reach one million barrels daily by the middle eighties (which would represent over three percent of our projected requirements), but leaves the impression that since this would not completely solve the problem, the advisability of oil shale development is questionable.

After discarding imported energy as a viable solution (and rightly so), the report searches for the one best source to satisfy our energy requirements rather than considering a broad energy mix. In the process, the importance of sources such as oil shale, North slope oil and coal synthetics is downplayed because none could completely fill the supply/requirement gap. The outer continental shelf as a source for oil and gas is completely ignored and secondary and tertiary recovery from existing on-shore reservoirs are treated only superficially.

Finally, the report fails to adequately analyze the critically important time factor associated with development of new energy sources and provides surprisingly little support for conservation measures.

# # # #

JCAE PROVIDES USEFUL DISPLAYS TO AID THE INTERPRETATION OF ENERGY DATA

The Joint Committee on Atomic Energy (JCAE) has prepared a suite of displays which are designed to enable a person (who is not necessarily an energy specialist) to obtain a reasonable understanding of the problems, broad scale, and complexity of our national energy "dilemma."

The JCAE energy display system is comprised of 16 charts showing first the energy flow patterns for the years 1950, 1960, 1970, and the projected patterns for the years 1980 and 1990. Next, a series of displays are presented to show certain information such as efficiency, end uses, supply/demand, etc. at each 10-year time period through 1990.

The display system is based for the most part on information from the recent NPC study, "Report on U.S. Energy Outlook", and on data from the Department of the Interior; however, JCAE has changed the information based on "interpretations" by the Lawrence Livermore Laboratory.

The display is a convenient source of energy-related data. If fault is to be found, it would be in the interpretations of the projected data. For example, the huge increase in the use of nuclear energy projected for the near future may be more related to the wishful thinking of nuclear proponents than to reality. Or, the first oil from oil shale is projected to appear after 1985. This could be so, but with the federal prototype leasing program set for early implementation, oil from shale could well appear in the 1970's. Other predictions include continued reliance on imports of foreign oil, continuing expansion of coal use, the first coal gasification plant (mid-1970's), and a surprisingly-large dependence on solar energy.

The display system is described in detail in a report entitled, "Understanding the National Energy Dilemma," available from the Superintendent of Documents, GPO, stock number 5270-01947, price: $1.55.

Fourteen of the report's charts are reproduced on the following pages.

The charts on pages 1-7 and 1-8 depict the flow of energy for the years 1950 thru 1990. The charts on page 1-9 show changes in the efficiency, end uses, supply/demand and the form of energy use for the years 1955 thru 1985.

The four charts on page 1-10 relate energy supply and demand to illustrate various estimates of supply, demand, shortages and imports. The predictions of energy mixes thru the years 1985 and 2000, according to the report, do not necessarily reflect the views held by the JAEC but are described as reasonable options.

The chart on page 1-11 depicts the beginning, peak and decline of the fossil fuel era in the United States.

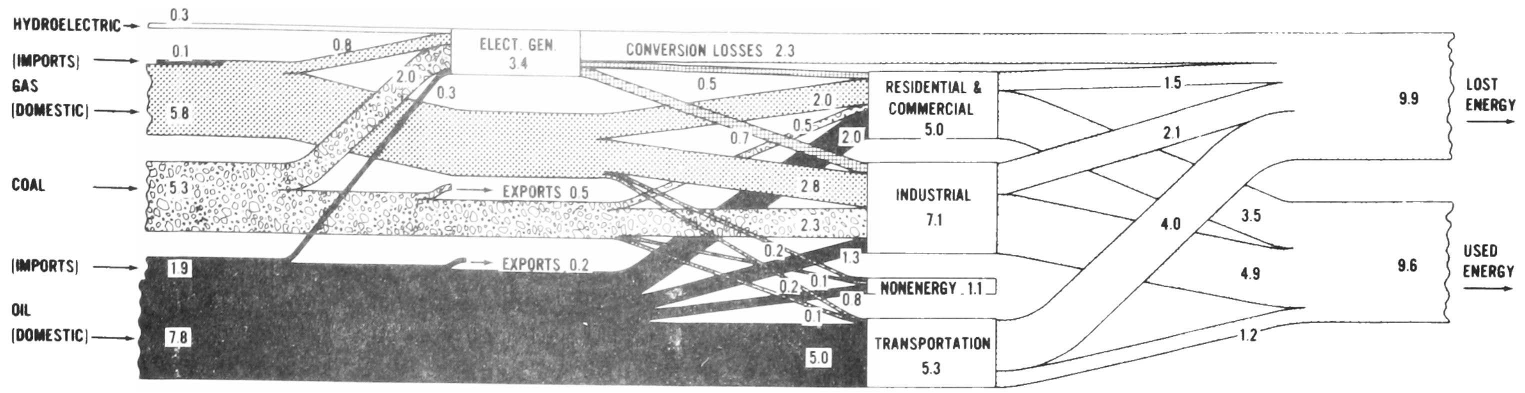
# # # #

JOINT COMMITTEE ON ATOMIC ENERGY SUPPLY/DEMAND CHARTS FROM

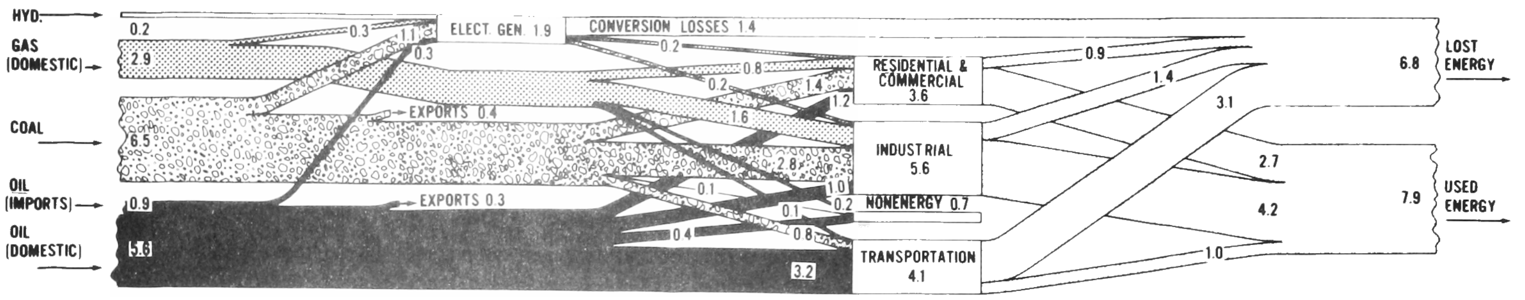
"UNDERSTANDING THE NATIONAL ENERGY DILEMMA"

(UNITS: MILLION BBLS/DAY OIL EQUIVALENT)

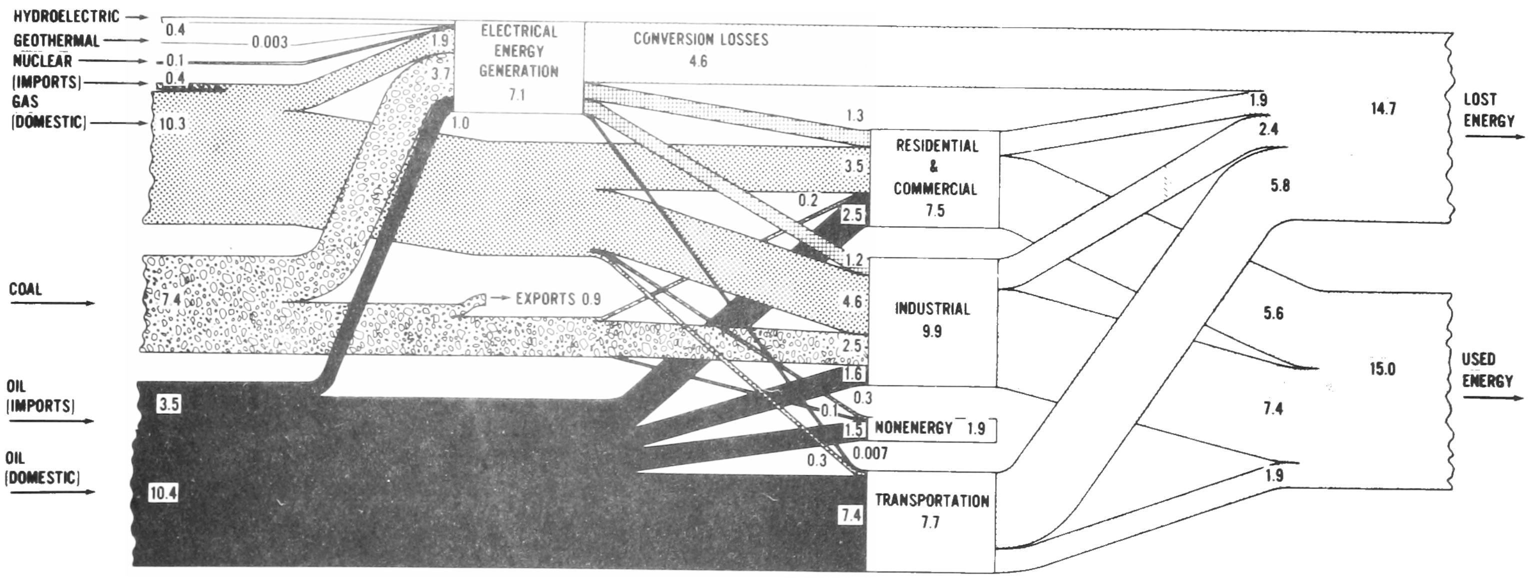
1950



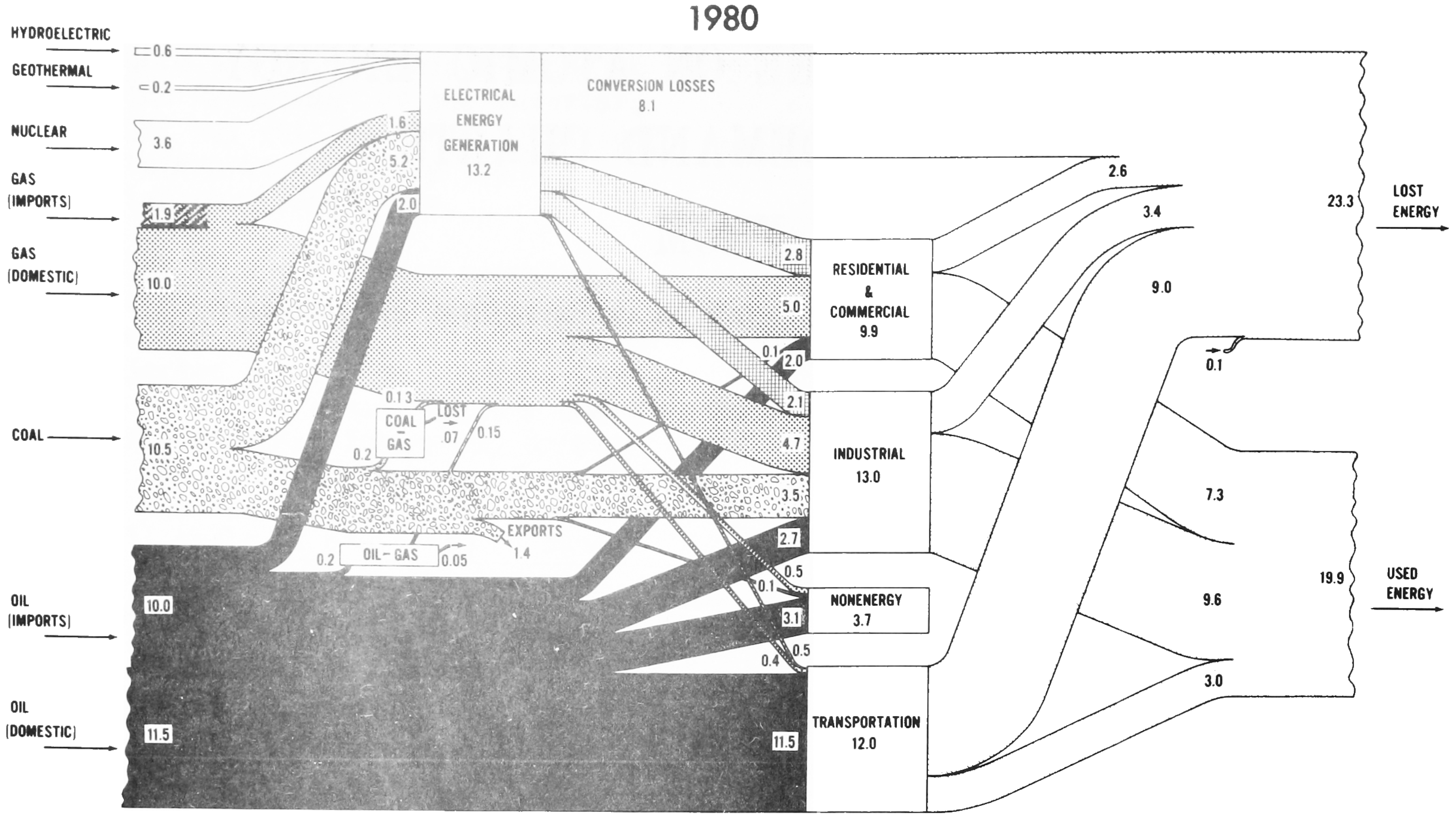
1960



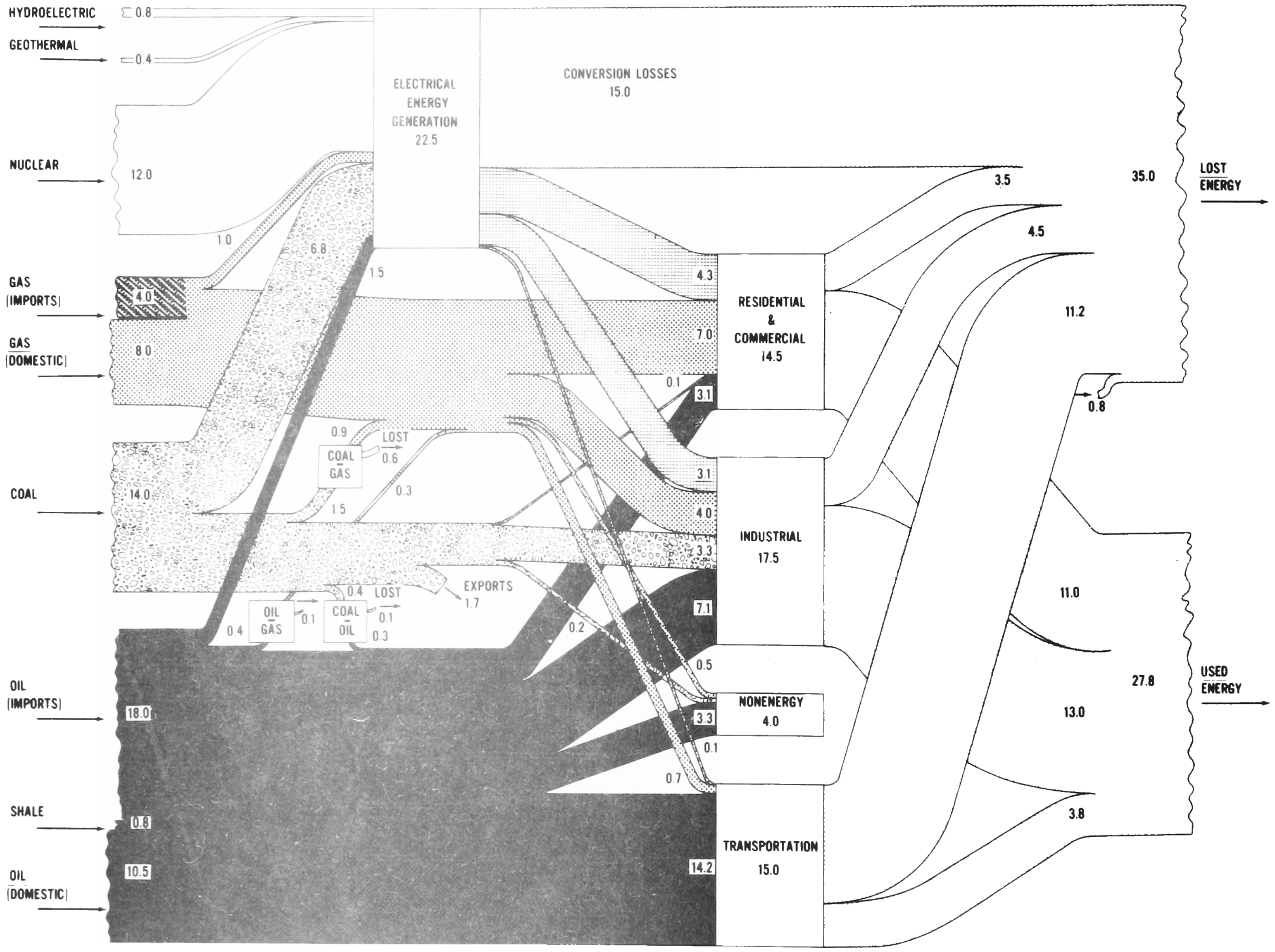
1970



1980


HYDROELECTRIC
0.6
GEOTHERMAL
0.2
NUCLEAR
3.6
GAS (IMPORTS)
1.9
GAS (DOMESTIC)
10.0
COAL
10.5
OIL (IMPORTS)
10.0
OIL (DOMESTIC)
11.5
1.6
5.2
2.0
ELECTRICAL ENERGY GENERATION 13.2
CONVERSION LOSSES 8.1
0.13
COAL - GAS
LOST
.07
0.15
0.2
EXPORTS 1.4
0.2
OIL - GAS
0.05
2.8
5.0
0.1
2.0
2.1
4.7
3.5
2.7
0.5
0.1
3.1
0.5
0.4
11.5
RESIDENTIAL & COMMERCIAL 9.9
INDUSTRIAL 13.0
NONENERGY 3.7
TRANSPORTATION 12.0
2.6
3.4
9.0
0.1
7.3
9.6
3.0
23.3
LOST ENERGY
19.9
USED ENERGY

1990


HYDROELECTRIC
0.8
GEOTHERMAL
0.4
NUCLEAR
12.0
1.0
6.8
1.5
GAS (IMPORTS)
4.0
GAS (DOMESTIC)
8.0
COAL
14.0
OIL (IMPORTS)
18.0
SHALE
0.8
OIL (DOMESTIC)
10.5
ELECTRICAL ENERGY GENERATION 22.5
CONVERSION LOSSES 15.0
0.9
COAL - GAS
LOST
0.6
0.3
1.5
EXPORTS 1.7
0.4
LOST
OIL - GAS
0.1
COAL - OIL
0.1
0.3
0.4
0.2
4.3
7.0
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3.1
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3.3
7.1
0.5
3.3
0.1
0.7
14.2
RESIDENTIAL & COMMERCIAL 14.5
INDUSTRIAL 17.5
NONENERGY 4.0
TRANSPORTATION 15.0
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4.5
11.2
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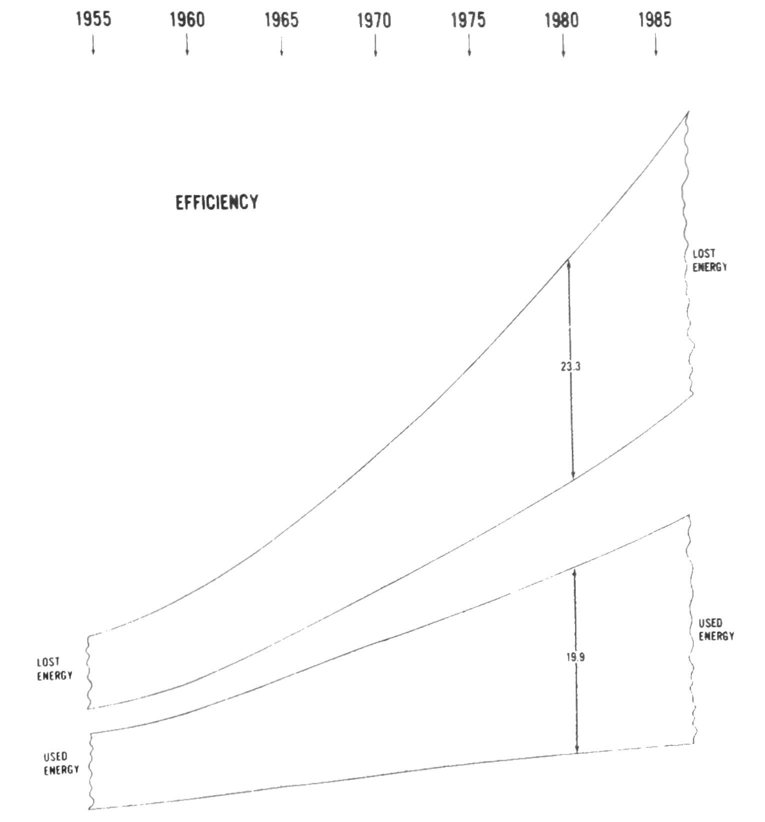
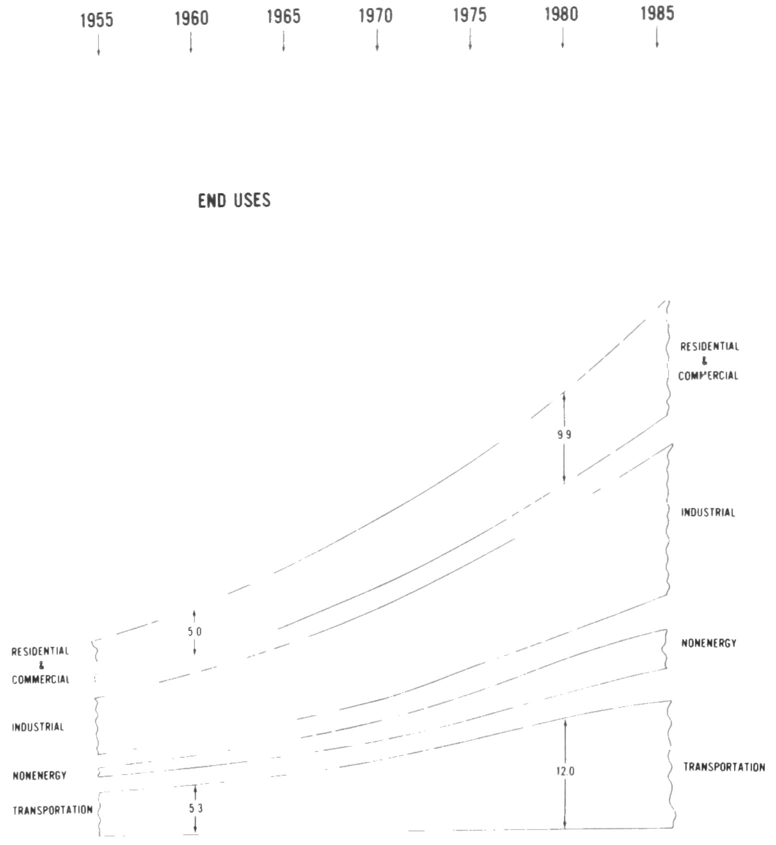
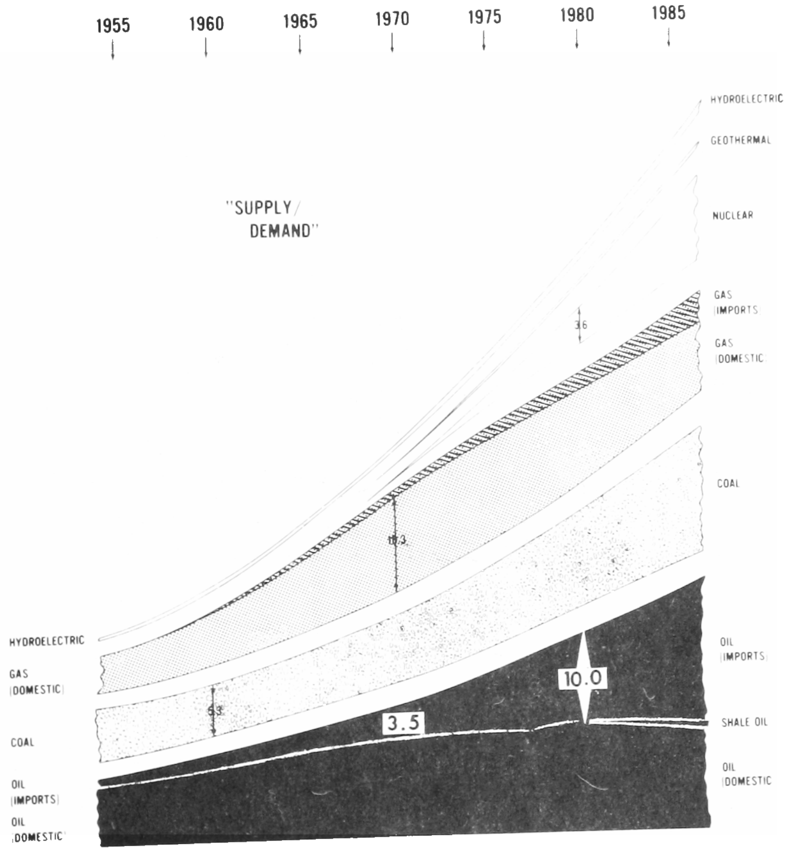
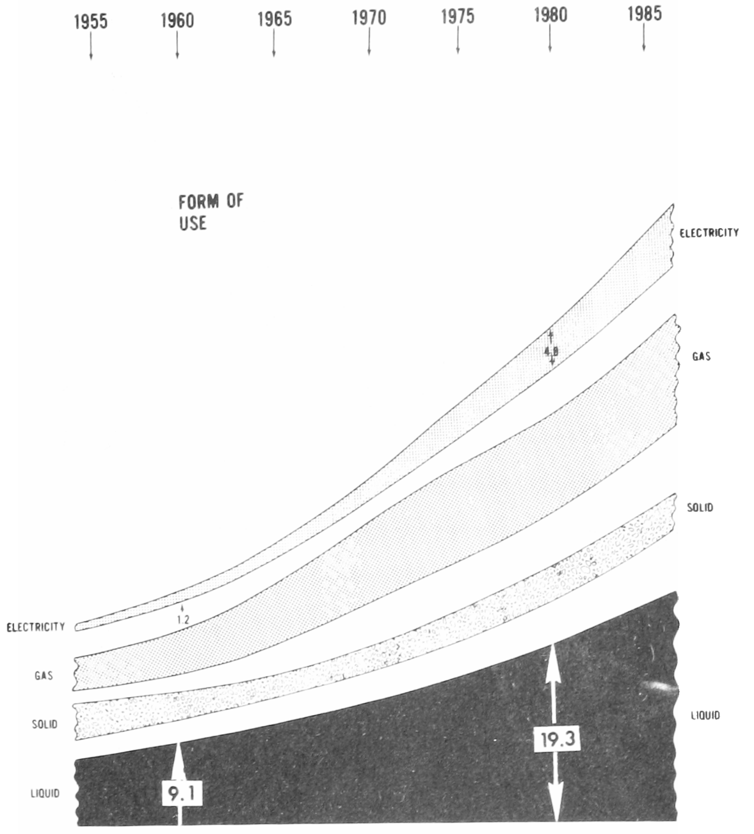
11.0
13.0
3.8
35.0
LOST ENERGY
27.8
USED ENERGY

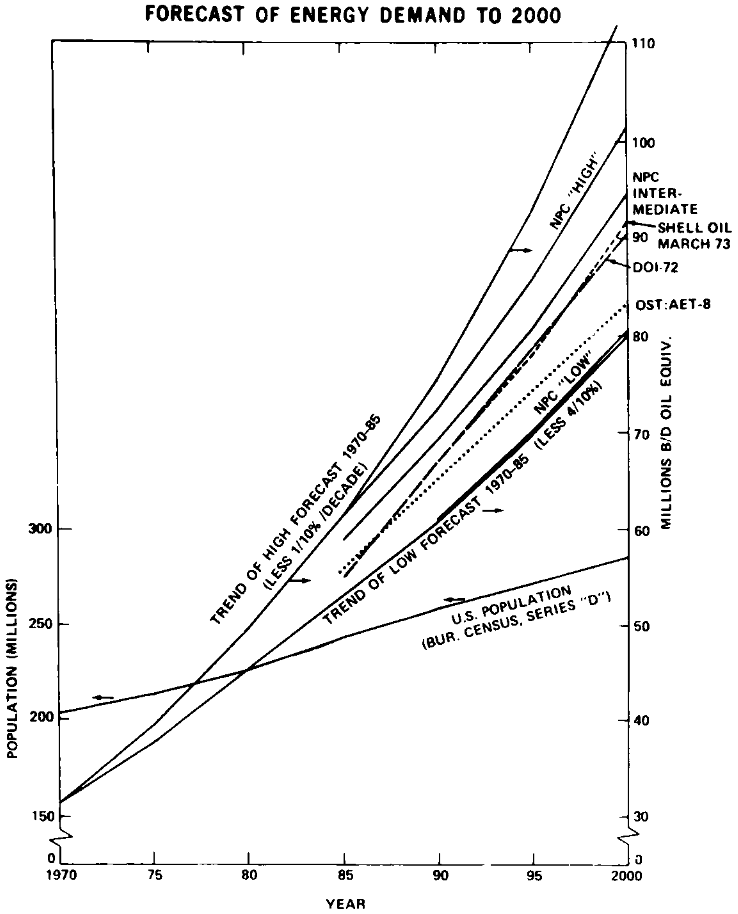

1955
1960
1965
1970
1975
1980
1985
EFFICIENCY
LOST ENERGY
23.3
USED ENERGY
19.9
LOST ENERGY
USED ENERGY


1955
1960
1965
1970
1975
1980
1985
END USES
RESIDENTIAL & COMMERCIAL
9.9
INDUSTRIAL
NONENERGY
TRANSPORTATION
12.0
5.0
RESIDENTIAL & COMMERCIAL
INDUSTRIAL
NONENERGY
TRANSPORTATION
5.3

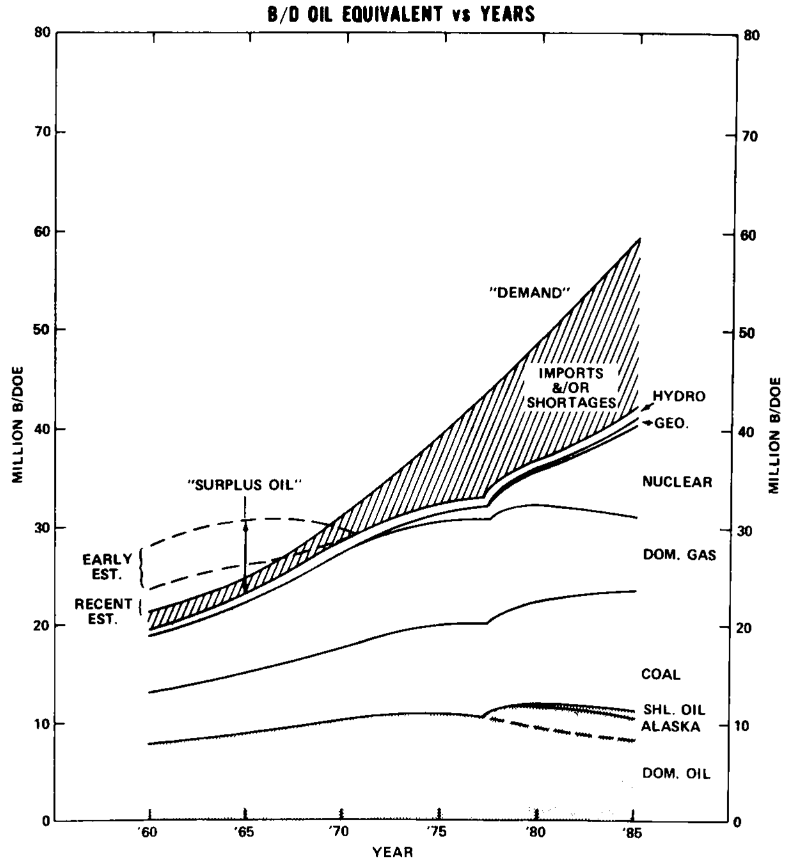

1955
1960
1965
1970
1975
1980
1985
"SUPPLY/ DEMAND"
HYDROELECTRIC
GEOTHERMAL
NUCLEAR
GAS IMPORTS
3.6
GAS (DOMESTIC)
COAL
OIL IMPORTS
10.0
SHALE OIL
3.5
OIL (DOMESTIC)
HYDROELECTRIC
GAS (DOMESTIC)
COAL
OIL (IMPORTS)
OIL (DOMESTIC)


1955
1960
1965
1970
1975
1980
1985
FORM OF USE
ELECTRICITY
4.8
GAS
SOLID
LIQUID
19.3
ELECTRICITY
1.2
GAS
SOLID
LIQUID
9.1

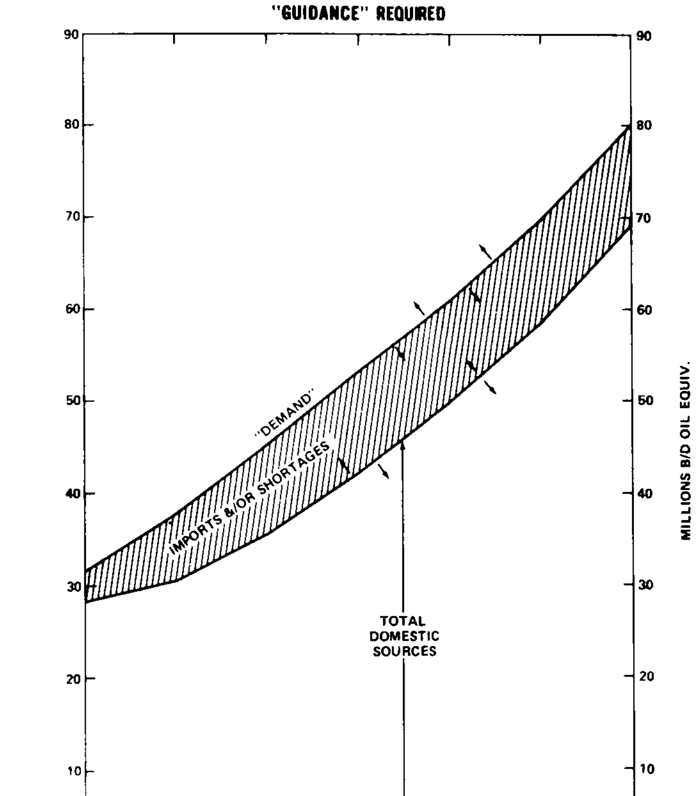
FORECAST OF ENERGY DEMAND TO 2000



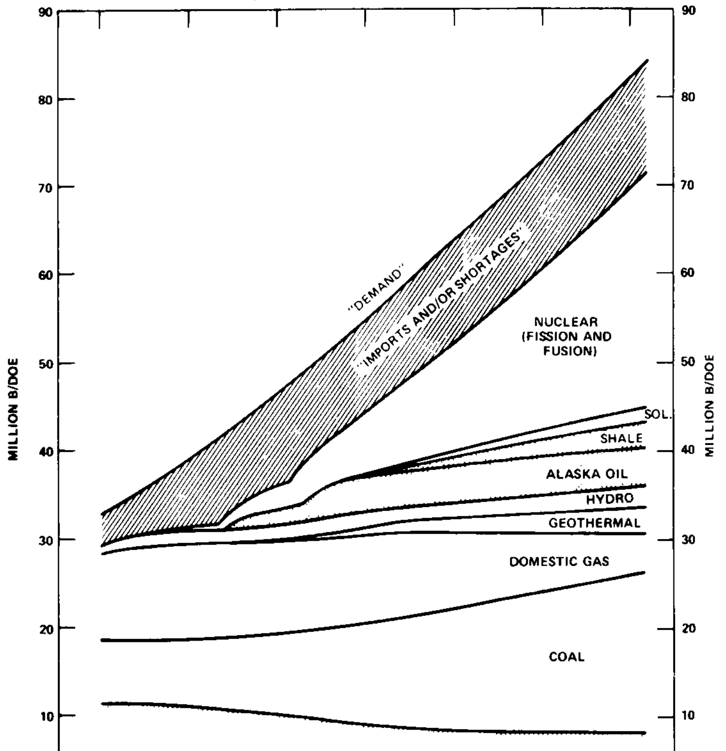
"SUPPLY/DEMAND"
(1960-1985)
B/D OIL EQUIVALENT vs YEARS

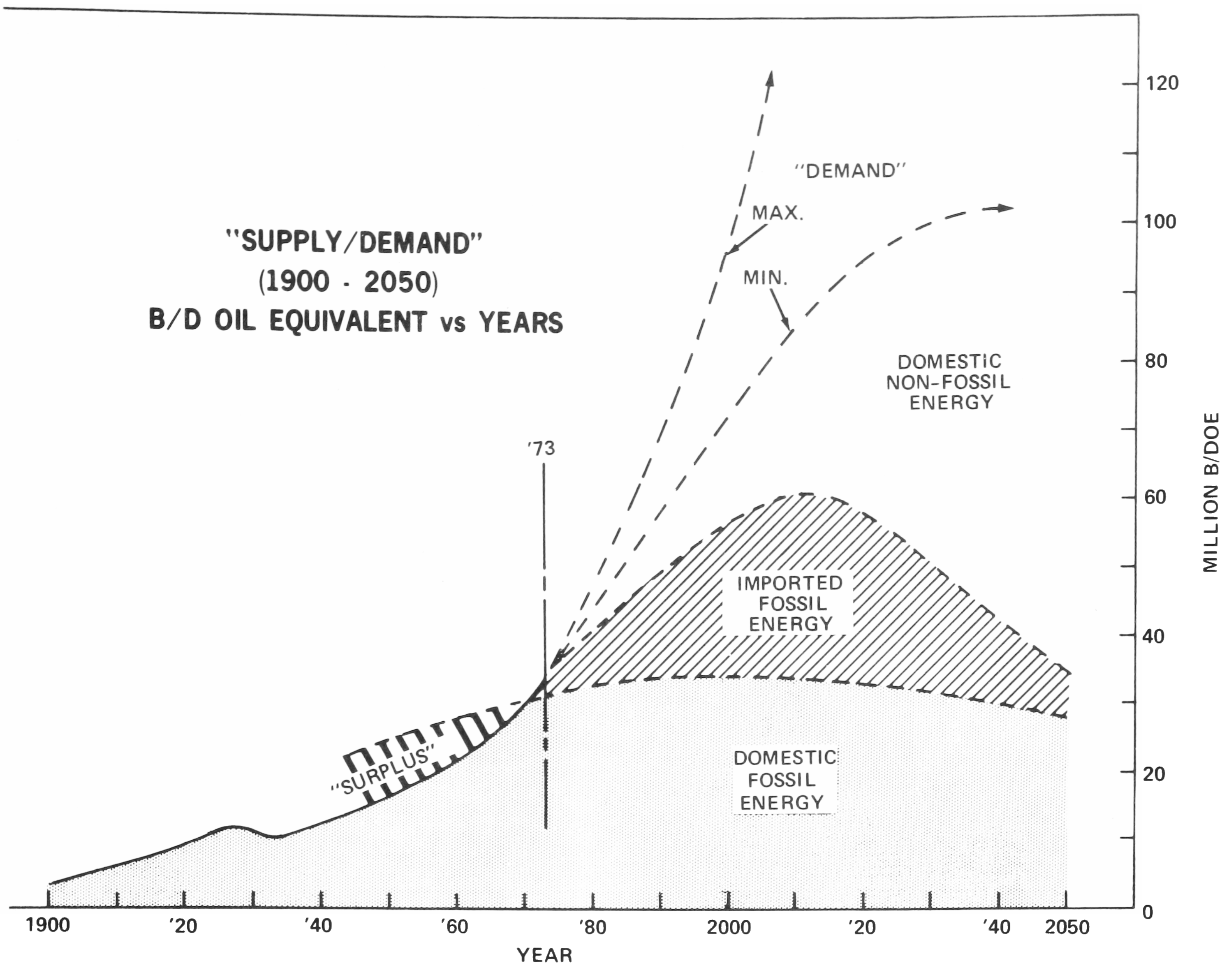


"GUIDANCE" REQUIRED



"SUPPLY/DEMAND"
(JCAE "OPTION EXERCISE 7-A" 3-73)
B/D OIL EQUIVALENT vs YEARS




"SUPPLY/DEMAND"
(1900 - 2050)
B/D OIL EQUIVALENT vs YEARS
"DEMAND"
MAX.
MIN.
DOMESTIC
NON-FOSSIL
ENERGY
'73
IMPORTED
FOSSIL
ENERGY
"SURPLUS"
DOMESTIC
FOSSIL
ENERGY
120
100
80
60
40
20
0
MILLION B/DOE
1900
'20
'40
'60
'80
2000
'20
'40
2050
YEAR

S.1807 AND H.R. 7775 PROPOSE SALINITY CONTROL PROGRAM FOR THE COLORADO RIVER

U.S. Senator Tunney and U.S. Representative Johnson, along with other legislators from states in the Colorado River drainage area, introduced Senate Bill 1807, and House Bill 7775, companion bills to enact the proposed "Colorado River Basin Salinity Control Act of 1973."

Large deposits of coal and oil shale occur in the Colorado River Basin. The provisions of this act could affect both the availability and cost of water in the area and would increase the cost of electrical power from U.S. Bureau of Reclamation generating stations operating under the Colorado River Storage Project Act (70 Stat. 105; 43 U.S.C. 620).

These bills, if enacted, will direct the Secretary of the Interior to implement the salinity control policy adopted for the Colorado River in the "Conclusions and Recommendations published in the Proceedings of the Reconvened Seventh Session of the Conference in the Matter of Pollution of the Interstate Waters of the Colorado River and Its Tributaries in the States of California, Colorado, Utah, Arizona, Nevada, New Mexico and Wyoming." That session was held in Denver on April 26-27, 1972 under the authority of section 10 of the Federal Water Pollution Control Act (33 U.S.C. 1160), and approved by the Administrator of the Environmental Protection Agency on June 9, 1972.

This would call for immediate programs to prevent salt waters from entering the river from known sources (La Verkin Springs, Paradox Valley, Grand Valley, etc.), and to study irrigation pollution source control, other point sources control, and diffuse sources control.

Costs of all investigations and works would be borne partly by the Federal government (which owns much of the lands), by the Upper Colorado River Basin Fund, and the Lower Colorado River Basin Fund. As these funds derive their monies from sale of Colorado River Storage Act Power, upward "adjustments" would be made in future charges for electrical power from Colorado River Storage Project Act generators (such as Flaming Gorge, Lake Powell and Curecanti).

The Bills are being considered by the Senate and House Committees on Interior and Insular Affairs.

# # # #

WYOMING FRAMEWORK PLANT DESCRIBES FUTURE WATER ALTERNATIVES

Five years of work by the Wyoming Water Planning Program culminated recently with issuance of "The Wyoming Framework Water Plan," dated May 1973. The 243-page report to the people of Wyoming provides information that will be valuable in making practical decisions concerning future water and related land resource development throughout the state. The preface to the report specifically notes that the Plan does not attempt to prescribe a course of action but provides data on which sound decisions can be based.

The Wyoming Water Planning Program is a division of the State engineer's office established to carry out legislative directives from the 39th Wyoming Legislature in 1967. The directives: (1) made the state engineer responsible for coordination of Wyoming's water and related land resources planning; and (2) directed the state engineer to initiate studies to plan the development of water allocated the State of Wyoming by the various compacts governing rivers flowing out of the state. In particular, the state engineer was asked to show the state's diligent intent to fully utilize all of Wyoming's compact shares of the Bighorn and Green River and their tributaries.

The Wyoming Framework Water Plan identifies the long-range (50-year) alternatives for meeting the water needs of the State. It is an inventory of the State's water resources and related lands, a summary of the State's present water uses, a projection of future water needs, an identification of physical alternatives for meeting the future water

Table 1*

Wyoming Average Annual Streamflows and Water Uses
Streamflow Base Period 1948-1968
(Figures in Acre-Feet)

River Basin & Subdrainage (1)	Streamflow Into Wyoming From Other States (2)	Water Yield Within Wyoming (3)	State Line Outflow-Natural Conditions (4)=(2)+(3)	Man's Depletions of Streamflow in Wyoming: Irrigation (5)	Municipal, Domestic, & Stock (6)	Industrial (7)	Reservoir Evaporation (8)	Total (9)	Depleted Streamflow Leaving Wyoming (10)=(4)-(9)
Missouri River Basin									
Yellowstone River	298,700	2,407,300	2,706,000	---	---	---	---	---	2,706,000
Clarks Fork	146,800	564,600	711,400	21,100	200	---	500	21,800	689,600
Bighorn River	---	3,676,100	3,676,100	1,007,400	5,700	2,200	104,500	1,119,800	2,556,300
Tongue River	---	386,300	386,300	77,100	2,400	1,000	3,100	83,600	302,700
Powder River	---	419,100	419,100	66,100	2,100	700	27,600	96,500	322,600
Little Missouri River	---	35,400	35,400	1,800	100	---	2,100	4,000	31,400
Belle Fourche River	---	96,700	96,700	1,500	1,000	1,000	16,800	20,300	76,400
Cheyenne River	---	85,700	85,700	4,500	600	1,700	14,100	20,900	64,800
Niobrara River	---	7,300	7,300	3,000	---	---	1,100	4,100	3,200
North Platte River	529,900	1,215,800	1,745,700	573,600	7,300	9,000	176,500	766,400	979,300
So. Platte River Basin	---	19,200	19,200	3,500	3,000	800	3,000	10,300	8,900
SUBTOTALS	975,400	8,913,500	9,888,900	1,759,600	22,400	16,400	349,300	2,147,700	7,741,200
Colorado River Basin									
Green River Basin	391,400	1,926,600	2,318,000	241,600	12,000	16,200	26,300	296,100	2,021,900
Great Basin									
Bear River	139,600	273,400	413,000	60,600	800	---	7,000	68,400	344,600
Columbia River Basin									
Snake River Basin	---	4,721,600	4,721,600	83,700	700	---	4,700	89,100	4,632,500
TOTALS	1,506,400	15,835,100	17,341,500	2,145,500	35,900	32,600	387,300	2,601,300	14,740,200

*Table I-9, p.29, from "Wyoming Framework Water Plan" needs, and an identification of alternative decisions to meet or not to meet the indicated future water needs. Copies of the Framework Plan may be obtained at:

Wyoming Water Planning Program
State Engineer's Office
State Office Building
Cheyenne, Wyoming 82002

Basin Reports Issued Earlier

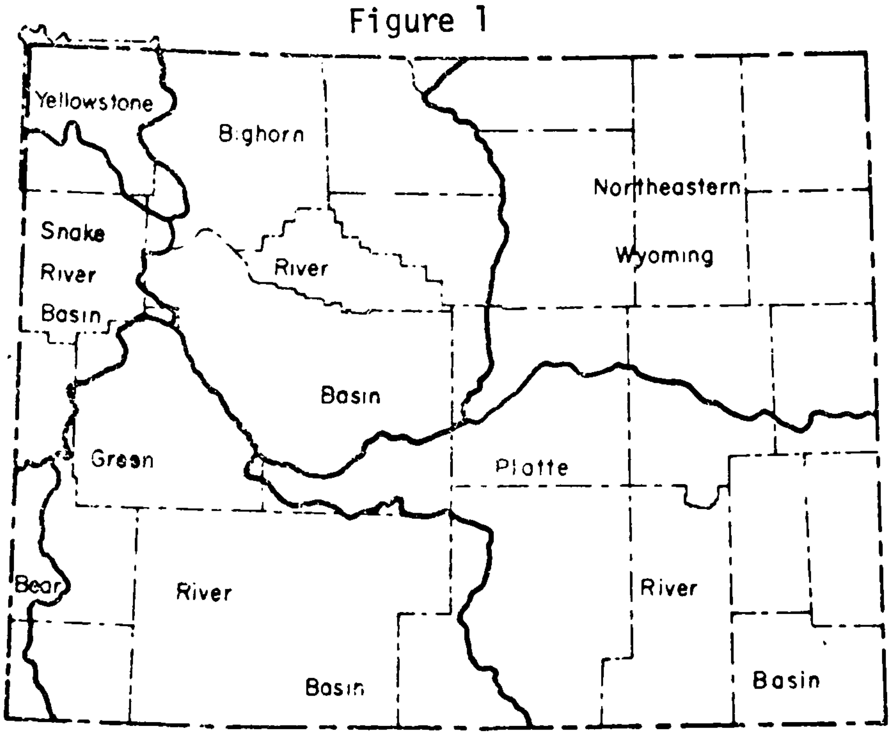
To carry out the purposes of the study, the state was divided into seven river basins, or groups of basins, as shown in Figure 1. Special reports were prepared for all except the drainages in Yellowstone National Park. Three of these reports were reviewed in Synthetic Fuels as follow:

(1) "Water and Related Land Resources of Northeastern Wyoming," September 1972 SF, p. 4-10

(2) "Water and Related Land Resources of the Green River Basin, Wyoming," March 1972 SF, p. 1-10

(3) "Water and Related Land Resources of the Platte River Basin, Wyoming," December 1971 SF, p. 1-12.

Figure 1



Wyoming Water Use Only 40% of Surface Water Entitlement

The Water Framework Plan begins with descriptions of the socioeconomic characteristics, land ownership patterns, physiography and climate of Wyoming, then slips into an excellent description of the state's surface water and groundwater resources.

Table 1 is a summary of streamflows and current water uses in Wyoming. It shows that present depletions in Wyoming amount to some 2.6 million acre-feet yearly (AFY). A review of the various river compacts governing the use of water in Wyoming indicates that an additonal 3.2 to 3.4 million AFY could be made available for use in the state. The remaining amount allocatable to the state varies from zero in the Great Basin to 2.5 million AFY in the Missouri River Basin. Table 2 further summarizes Wyoming water availability.

Table 2
Remaining Water Available
to Wyoming
by Compact

	Thousand AFY
Missouri River Basin	
Clarks Fork	429
Bighorn River	1800
Tongue River	96
Powder River	121
Belle Fourche River	7
Cheyenne River	15
North Platte	68
Subtotal	2536
Colorado River Basin	
Green River	579-747
Great Basin	
Bear River	0
Columbia River Basin	
Snake River	150
Total	3265-3433

In addition to the amounts given in Table 2, an estimated 494,000 AFY of water is available under the Yellowstone River Compact as supplemental supplies to existing pre-1950 water rights.

It is estimated in the report that total water consumption in Wyoming, exclusive of reservoir evaporation, could increase from an average of 2.4 million AFY at present to about 4.2 million AFY in the year 2020. This estimate is based in part on a report prepared by Cameron Engineers, Inc. in 1969 for the Department of Economic Planning and Development. Cameron's report, "Review and Forecast, Wyoming Mineral Industries," predicted that the water requirements of the mineral and timber industries alone would increase by nearly 800,000 AFY between 1970 and 2020, most of the increase being attributable to a coal production predicted by Cameron to reach 350 million tons annually by 2020. Thus the "Framework Water Plan" leaves no doubt that Wyoming is legally entitled to the use of more than enough surface water within her borders to meet anticipated demands for many years into the future.

There are problems in putting surface water resources to use. For example, existing diversions use the dependable flows from most streams. Surpluses are available only during certain periods of the year such as the spring runoff period or during the winter months. Also, runoff varies widely from year to year which means that storage facilities would be necessary to effectively utilize surpluses. Still another important consideration is that future needs may not occur in an area of water surpluses; transbasin diversions would be necessary in many cases.

Groundwater Resource Estimated

According to the "Framework Plan," not all of the anticipated demand increase will be supplied by surface water. An estimated 15 percent could come from groundwater sources.

Present annual comsumptive use of groundwater on a statewide basis amounts to 133,500 AF for irrigation, 32,100 AF for municipal, domestic and stock uses, and 50,400 AF for industrial use. There is no precise data for estimating groundwater available in Wyoming, but the amount in storage is enormous. In many areas, however, aquifers either are too deep or display characteristics unsatisfactory for water to be obtained in significant amounts or of suitable quality. Based on existing information the estimated average annual recharge rate (which may be implied to be an estimated maximum permissible withdrawal rate) amounts to some four million acre-feet. A larger withdrawal rate is, of course, possible if some annual depletion of water storage is determined to be acceptable.

Table 3 is a summary of Wyoming groundwater resources.

Projected Water Requirements

Table 4 is a summary of the present and projected Wyoming water requirements through the year 2020. Increased uses of water for irrigation and industrial purposes are expected to account for nearly 95 percent of the increase during the years 1973 and 2020. Major increases for industrial purposes are forecast to occur in the Green River Basin where the state's oil shale is found and in northeastern Wyoming where most of the coal resources are found. Industrial use of water in northeastern Wyoming alone is expected to increase from 21,000 AFY in 1973 to 477,000 AFY in 2020.

Situation summaries concering water availability in the Bighorn and Green River Basins and in northeastern Wyoming are given in the following paragraphs.

Bighorn River Basin

Although there is an apparent abundance of water available in the Bighorn River system, developing a usable firm supply is dependent upon the availability of storage water and storage sites. Water for new uses is presently available from Buffalo Bill, Boysen, and Bighorn Lake Reservoirs. Use of all of Wyoming's compact allocation would require the construction of additional storage, and at least a portion of the water supply would have to be diverted from Bighorn Lake or

Table 3

WYOMING GROUNDWATER STORAGE & RECHARGE SUMMARY
Thousand Acre-Feet

	Alluvium		Major Teritary Sandstone Aquifers	Bedrock Aquifers
	Storage	Annual Recharge	Storage	Storage
1. Yellowstone	2250	--	--	--
2. Bighorn	930	180	30,000	723,000
3. Northeastern Wyoming	750	125	30,000	935,000
4. Platte	3200	410 1/	90,000	257,000
5. Green River	700	90	30,000	1,193,000
6. Bear River	765	50	--	--
7. Snake River	1800	400	--	--
	10,195	1255	180,000	3,108,000

1/ Includes an estimated 200,000 AF of artificial recharge from irrigation

Table 4

WYOMING
WATER RESOURCE REQUIREMENTS
PRESENT & FUTURE

Basin	Consumptive Use thousand AFY 1973	1980	2000	2020
Bighorn River	1082	1217	1391	1484
Northeastern Wyoming	195	255	419	659
Platte River	723	806	941	1141
Green River	277	410	527	681
Bear River	66	74	92	110
Snake River	86	98	102	113
Statewide Total	2429	2860	3472	4188

from the river system below Yellowtail Dam. There is also a need for intrabasin diversions of water, or diversions from streams in the Bighorn River Basin with water surpluses to other streams in the Bighorn River Basin which are water short, in order to provide full water supplies for all existing uses.

Northeastern Wyoming

The projected M & I water needs in Northeastern Wyoming, associated primarily with coal and related industries, could require water supplies in excess of locally available supplies. After deducting reservoir evaporation, a supply of about 86,000 AFY could be made available for use in Wyoming on the Tongue River. A total M & I water supply of about 137,000 AFY has been identified on the Powder River (Lake DeSmet, plus Hole-in-the-wall, plus Moorhead or Clear Creek Reservoirs). Coordination of development and water resource management will be required in order to achieve this degree of total water availability. Additional supplies may be available in the Little Missouri, Bell Fourche, and Cheyenne River systems. Desalination may be required to utilize water from the Powder River and other streams east of the Powder River.

Groundwater could be utilized as a stage in the development of Northeastern Wyoming resources. Large-scale groundwater utilization will require mining of the resource, and in time the use will have to be curtailed or replaced with imported surface water.

Because individual industries will require water reserves and development projects will take a period of years to develop, the exact timing of the need for imported water supplies is difficult to ascertain. It appears logical to develop the locally available water supplies as a first stage in a development, then construct water importations as a later phase. However, it may be advantageous for water importation to proceed in an initial phase.

A considerable portion of the projected increased water demand in Northeastern Wyoming will occur in the coal fields which lie north and south of Gillette. Five alternative pipelines from the Bighorn River or Yellowstone River to the Gillette area and one from Green River to Gillette via the North Platte River have been identified. The language of the Yellowstone River Compact, however, must be considered regarding the proposals for transbasin diversions to the coal fields lying outside the Yellowstone River Basin: "No water shall be diverted from the Yellowstone River Basin without the unanimous consent of all the signatory states." The signatory states are Wyoming, Montana, and North Dakota. In order to get consent it would appear that regional factors must be considered so that the states can agree that a transbasin diversion can be made. In view of this, perhaps one of the downstream diversions that provide water for industries in both Montana and Wyoming may be a logical approach.

If consent cannot be obtained to utilize Yellowstone River Compact water in the coal fields outside of the Yellowstone River Basin, it may be necessary to utilize water from other areas of the State. The terms of the Colorado River Compact and the Upper Colorado River Basin Compact do not place restrictions on the place of use of water, and Wyoming may find the use of Green River water in Northeastern Wyoming to be an attractive alternative to utilizing Yellowstone River water.

Green River Basin

The Green River Basin is rich in mineral resources which include coal, uranium, oil shale, and trona. Green River Basin industrial water use is projected to increase elevenfold in the next 50 years. Storage capacity in Fontenelle Reservoir can be utilized to develop M & I water supplies, and in combination with another reservoir, the remainder of Wyoming's compact allocation could be developed for both Green River Basin M & I needs and for use in other river basins of Wyoming. Five alternative reservoirs have been identified for this purpose. Groundwater will likely be utilized to meet a portion of the M & I water need.

Surface water depletions in Wyoming's Green River Basin are projected to increase to 771,000 AFY by the year 2020, leaving between 104,000 and 272,000 AFY available for use elsewhere in Wyoming.

# # # #

RAINBOW BRIDGE DECISION APPEALED TO SUPREME COURT

Friends of the Earth et al have asked the Supreme Court to reverse the decision of the 10th U.S. Circuit Court of Appeals in their fight to keep the waters of Lake Powell out of Rainbow Bridge National Monument. Previous articles on the Lake Powell/ Rainbow Bridge controversy appeared in the June 1973 issue of Synthetic Fuels, page 1-6 and in the September, 1973 issue, page 1-10.

On August 10, 1973, the appellate court reversed the decision of Judge Willis Ritter that barred the intrusion of Lake Powell into Rainbow Bridge National Monument. The Circuit Court ruled in a 5-2 decision that Congress had, by implication, repealed two provisions of the 1956 Colorado River Storage Act which were intended to prevent water from entering the national monument.

In their appeal to the Supreme Court, the plaintiffs state that the appellate court judgement contradicts numerous Supreme Court decisions as well as decisions of other courts defining the power of courts to declare statutes repealed by implication. "Furthermore," the plaintiffs allege, "the judgement interferes with an on-going legislative process and violates the doctrine of separation of powers by disposing of questions of national concern, including questions involving National Parks and Monuments, that are in the province of Congress and that are presently before Congress for disposition."

The defendents had 30 days to respond to the appeal which was filed on October 27. Specificially, the appeal by Friends of the Earth raises the following questions:

(1) Whether Section 3 of the Colorado River Storage Act of 1956 has been impliedly repealed or rendered inoperative; and

(2) Whether the decision of the U.S. Court of Appeals for the 10th Circuit is a violation of the doctrine of separation of powers.

Section 3 of the 1956 Storage Act states, in part, that "...it is the intention of Congress that no dam or reservoir constructed under the authorization of this Act shall be within any national park or monument.

Section 1 of the Act directs that "...as part of the Glen Canyon Unit, the Secretary of the Interior shall take adequate protective measures to preclude impairment of the Rainbow Bridge National Monument."

The 10th Circuit Appellate Court ruled that these provisions of the Storage Act had essentially been rendered inoperative because of identical provisos contained each year since 1961 in the public works appropriations act: "that no part of the funds herein appropriated shall be available for construction or operation of facilities to prevent waters of Lake Powell from entering any National Monument."

# # # #

II
oil shale

GARFIELD COUNTY, COLORADO ZONING REGULATIONS AFFECT OIL SHALE DEVELOPMENT

On November 20, 1973 the Garfield County (Colorado) Board of County Commissioners adopted zoning regulations that include provisions for the development of natural resources in general and for oil shale development in particular. The county has been wrestling with the problem for several years and this past summer nearly approved a resolution that was considerably less acceptable to industry than the resolution ultimately approved.

The resolution approved on November 20 affects fee oil shale lands in Garfield county that are controlled by the following companies and partnerships:

- Amoco Production
- ARCO
- Cities Service
- Colony Development Operation
- Conoco
- D. A. Shale Inc.
- Equity
- Exxon
- Getty
- Mobil
- Shell
- Standard of California
- Tenneco
- Texaco Inc.
- Union Oil of California

First Plan Failed

In responding to a need to zone the western two-thirds of the county, the commissioners were faced with the problem of effectively zoning the oil shale area without closing the door on future development.

The oil shale deposits of major significance in Colorado are located in Garfield and Rio Blanco counties. Most of the fee oil shale properties controlled by major oil companies are located in Garfield County while most of the Federal oil shale lands are in Rio Blanco County. Notable exceptions are the Naval Oil Shale Reserves 1 and 3 which are in Garfield County. The county's legal authority for controlling land use on the Naval Reserves is not clear, but there is no question that control of private lands is possible.

The fee oil shale lands in Garfield County are located in two principal drainages: Roan Creek on the west and Parachute Creek on the east. In July of this year the county commissioner considered a resolution that essentially would have created industrial zoning in the Parachute Creek Drainage and agricultural zoning in the Roan Creek drainage. The Roan Creek drainage was further subdivided into an agricultural-in-transition-to-industrial zone above the Mahogany marker outcrop and an agricultural-in-transition-to-residential zone below the outcrop, thus precluding any type of industrial activity in the Roan Creek Valley. This plan met with stern opposition from such companies as ARCO and Getty and was subsequently withdrawn by the commissioners.

Resource Lands District Created

The zoning resolution ultimately adopted attacks the problem in a different manner. A special zoning district called the Resource Lands District was created. The district's boundaries are state highway 13 (which connects Rifle and Meeker) on the east, the Colorado River on the south, state highway 139 (the Douglas Pass road) on the west and the Rio Blanco/Garfield county line on the north.

The Resource Lands District is further subdivided into four zone classifications as follow:

(1) Plateau -- the rolling lands of the highest elevation in the area and generally found above the escarpment

(2) Escarpment -- includes the fixed bedrock forming vertical or near vertical parts of the canyon walls

(3) Talus Slopes -- loose deposits of rock debris accumulated at the base of a cliff or slope

(4) Gentle slopes and lower valley floor -- colluvial and alluvial soil at the base of talus slopes in the lower valley floor.

Permit Required for Oil Shale Development

Three use classifications (by right, conditional, and special) are identified for each subzone in the resource district. The principal land uses in the Roan Creek and Parachute Creek drainages are farming and ranching. These uses are recognized and are the only uses that by right can be made of the affected lands. More specifically, the zoning resolution lists the following uses by right: ranching, farming and general agriculture, accessory uses and structures related to agriculture, single family swelling units related to an individual ranch or homestead, and guiding and outfitting. Additional uses such as kennels riding stables, verterinary clinics and retail establishments for the sale of goods prossessed from raw materials produced on the land are permitted in the lower valley floors.

All activities related to oil shale development (mining, crushing, retorting, upgrading, waste disposal, etc.) are classified as either conditional or special uses and as such require county approval in the form of a permit.

Impact Statement Required

An application for either a conditional or special use permit must be accompanied by an impact statement on the proposed use describing its location, scope, and design, including an explanation of its operational characteristics. The impact statement must also show that the proposed use shall be designed and operated in compliance with all applicable county, state and federal laws and regulations and will not have a significant adverse effect on:

(1) existing lawful use of water through depletion or pollution of surface or groundwater;

(2) the use of adjacent land through generation of vapor, dust, smoke, noise, glare, vibration, etc; or

(3) wildlife and domestic animals through creation of hazardous attractions, blockade of migration route or patterns or other means.

In addition to the impact statement, the county commissioners may, at their discretion, require a written explanation of methods to be used to minimize smoke, dust, odors and similar environmental problems which might result from the proposed use.

Another requirement of any oil shale operation is that a site rehabilitation plan be submitted to and approved by the county commissioners, who, at their discretion, may require a bond or other form of security to guarantee that a rehabilitation plan is followed.

Where a potential water pollution problem exists, it will be necessary to install safeguards designed to comply with the regulations of the Environmental Protection Agency before operations may begin. Also, all percolation tests or ground water resource tests required by local or state health officers must be performed before operations may begin.

Solid Waste Disposal Specifically Affected

Aside from the influx of new people and the impact on regional water supplies, the concern most commonly expressed by people in western Colorado regarding oil shale development is the disposal of spent shale. It is not surprising then, that of all the operations involved in oil shale development, only spent shale and overburden disposal, and more specifically "mineral waste disposal" is considered to be a special use anywhere within the oil shale lands district except above the escarpment which essentially means above the outcrop of the Mahogany marker. Here mineral waste disposal is a conditional use.

All other activities associated with oil shale development are considered to be conditional uses. If Federal and state standards and regulations are met, there will be no problem in meeting county requirements for conditional uses.

Where solid waste disposal is a special use (which includes canyons leading into Parachute

Creek such as Garden Gulch) such use not only must meet Federal and state standards but must also be approved by the Garfield County Board of Zoning Adjustments who may impose additional provisions or restrictions as deemed necessary to protect the health, safety and welfare of the general public. Even if the Board of Adjustments approves a special use the Board of County Commissioners may deny a request for a special use based on the lack of physical separation in terms of distance from similar uses on the same or other sites; the impact on traffic volume and safety or on utilities; or any impact of the special use which it deems injurious to the established character of the zone district in which the special use is proposed.

Summary

Whereas a resource lands district is created specifically to take care of Garfield County's unique situation with respect to potential oil shale development, the requirements of industrial operations are not unique with oil shale operations. Garfield county officials obviously do not wish to preclude the possibility of oil shale development but they do wish to exercise as much authority as possible over how an industry develops. One may wince at the requirement of an impact statement for a county government, but some form of impact statement will be required for operations on private land from the state or federal government anyhow. Garfield county will probably not require more detail than required in a Federal or state impact statement. The county is merely guaranteeing that they be fully informed of developments occurring in their own backyard. No one can argue with that goal because it is equally desirable from industry's viewpoint.

In our opinion Garfield county has created a workable zoning resolution, one that essentially provides for consideration of future industrial developments on a case-by-case basis.

# # # #

PICEANCE BASIN OIL SHALE COREHOLE MAP UPDATED

The Cameron Engineers' map showing the location of oil shale coreholes and assayed wells in the Piceance Creek Basin has been updated; a copy of the map and accompanying booklet is included in the pocket inside the back cover of this issue.

The map was originally published in December 1969. The current edition includes information on 102 coreholes and wells that have either been drilled or reported since December 1969. There are a total of 436 drilling locations shown on the new map, of which more than 200 have been publicly reported in some detail.

A third of the drilling activity since 1969 is attributable to Interior's prototype leasing program, during which more than 30 coreholes have been drilled. Data from these coreholes are not publicly available as yet, but when Interior formally announced the program in June 1971, a notice published in the Federal Register directed that such data will be made public when either the tract (on which such coreholes are located) is leased or no later than five years from the date of drilling.

# # # #

STATUS OF OIL SHALE LEGAL PROCEEDINGS NOTED

The status of Bureau of Land Management administrative contests and Federal district court cases concerning title to oil shale mineral rights on lands in Colorado, Utah and Wyoming is summarized in Table 1. Few significant changes have occurred since Sept., 1973.

Of interest, however, is the fact that Merle I. Zweifel, et al filed two suits in U.S. district court in Denver seeking to overturn a BLM decision that declared 2910 placer claims in the Piceance Basin null and void. The civil action numbers of the suits filed recently are 5276 and 5308, but the status may be found described under BLM contest No. 441.

Motion for summary judgement in Civil Actions 4135 and 4139 will be heard shortly after the

TABLE 1

STATUS OF OIL SHALE LEGAL PROCEEDINGS

BEFORE OFFICE OF HEARINGS AND APPEALS, DEPARTMENT OF INTERIOR

Contest Number	Contestant/Contestee	Issues Involved & Status
Colo. 359-360	USA/F. W. Winegar, et al	Contestant seeking to invalidate oil shale claims held by contestees on basis of no discovery. Recommended decision issued by BLM hearing examiner on 4/17/70 wherein 3 claims were declared invalid and 6 claims adjudged to be valid. BLM filed appeal brief on 6/12/70. Contestee's filed answer briefs to appeal brief. Interior Board of Land Appeals (IBLA) has not issued ruling.
Colo. 441	USA/Merle I. Zweifel, et al	Complaint field 8/17/68 by BLM alleging mining claims filed by Zweifel are invalid because claims were not located in accordance with mining law and no discovery of valuable minerals was made. Decision issued 2/25/72 declares all claims null and void. (See June 1972 issue, page 2-1, for details). Decision was appealed to the Office of Hearings and Appeals. Appeal rejected. Zweifel initiated Civil Action No. 5276 in the U.S. District Court in Denver on August 16, 1973, seeking review by the Court of Interior's actions and asking that the claims be declared valid and in full force. This action involves 2,910 mining claims in Rio Blanco, Garfield and Moffat Counties, Colorado. These claims cover both proposed prototype oil shale leasing program sites (C-a and C-b) in Colorado.
Utah 22127 Utah 22606	USA/F.H. Larson	The Gulf Oil Corporation, Larson Oil Co., Frederick H. Larson and Dorothy H. Larson relinquished and quit-claimed to the United States all their interests in pre-1920 mining claims within oil shale leasing selected sites a & b in Uintah County, Utah. This relinquishment only clears title to certain claims. The relinquishment has been recorded and accepted. The following case files have been closed: (1) U-22127 Davis Nos. 27-33 Frederick Larson, et al (7 claims) (2) U-22606 Best Nos. 69-76 Gulf Oil Co., Larson Oil Co. (8 claims).

BUREAU OF LAND MANAGEMENT ADMINISTRATIVE CONTESTS

Contest Number	Contestant/Contestee	Issues Involved & Status
Colo. 193 & 260	USA/TOSCO	These contests will be decided by the courts in Civil Actions 8680, 8685, 8691, 9202, all of which cases are before the U.S. District Court in Colorado.
Colo. 506	USA/Buttertop Mining Co.	BLM is contesting the Virginia, Osage and Louie Placer Mining Claims in Twps. 2 and 3N, Ranges 98 and 99W, 6PM, Colorado, charging that valuable minerals were not discovered. This contest is awaiting the 30-day period following the republication of the notice to contestees. No answers were filed responding to publication of notices. The claims have been declared null and void.
Colo. 510	USA/Beatrice Bills, et al	BLM is contesting the Sand Asphaltum Placer Mining Claims in T3S, R96W, 6PM, Colorado charging that valuable minerals were not discovered. The decision has been served declaring fractional interests in some and total interests in the remaining claims null and void for failure to answer the complaint. Answers for fractional interests in 63 of the claims have been filed and the validity of these fractional interests will be decided in a hearing. The Sand Asphaltum No. 209 mining claim on selected proposed prototype oil shale lease site C-b is null and void for failure to answer the complaint. This contest has been transferred to the Office of Hearings and Appeals (Interior) in Salt Lake City for hearing on 46 claims. The remaining 270 claims are null and void. Government has requested a pre-hearing conference.
Wyoming W-30079, etc.	USA/Numerous defendants	20 complaints out of 33 proposed have been filed, and service is in process on 216 pre-1920 mining claims in the Washakie basin.
Wyoming W-27951, etc.	USA/Merle I. Zweifel, et al	There are 27 separate contests against Zweifel in Wyoming involving 1687 claims, all in the Washakie Basin oil shale area. BLM is seeking to invalidate the claims on bases of no mineral discovery and faulty locating procedures. The last publication notice has been printed. An answer was filed on behalf of all contestees by Zweifel. A decision is being served on almost all contestees declaring their interests null and void unless evidence is produced showing Zweifel had authority to answer on their behalf. Some of the served contestees have timely filed the required evidence; others have not. A timely answer was filed by C. T. Cooper for most of the contestees in 3 of the contests. (W-38091, W-28124, W-28126). Hearing held in Denver July 18-21, 1972 on these three contests during which BLM mineral examiners testified as to the validity of the claims involved. Two rulings in 24 of these contests have declared claims null and void.
Utah-10700	USA/Merle I. Zweifel	This contest, to clear title to the two sites selected in Utah for possible leasing under the proposed prototype oil shale leasing program, is being served by republication because of errors made in the original publication and in the second publication.

BEFORE U. S. DISTRICT COURT IN COLORADO

Civil Action Number	Plaintiff/Defendant	Issues Involved & Status
9252 9458 9461 9462 9464 9465	H. H. Hugg/Sec'y., Interior J. Savage/Sec'y. Interior Union Oil/Sec'y. Interior Equity Oil/Sec'y. Interior Gabbs Expl./Sec'y. Interior	Plaintiffs are contesting BLM administrative rejections of applications for patents on oil shale mining claims. Cases are pending until cases on related subject matter (see 8680-9202 below) are decided. In effect, these cases are closed and proceedings stayed, but with the right of any party to reopen. No change since June 1973.
8680 thru 9202	TOSCO/Sec'y. Interior Sec'y. of Interior/TOSCO	Tenth Circuit Court of Appeals decision of 2/4/69 upheld District Court decision that Appellee's claims cannot be adjudged invalid for failure to perform assessment work. Case appealed to U.S. Supreme Court 10/69. Supreme Court essentially reversed lower court decision 12/70 and remanded case to U. S. District Court. (See March 1971 issue of Synthetic Fuels, page 1-1 for details of U. S. Supreme Court decision.) An informal hearing was held on the continued cases in District Court on February 17, 1972. Plaintiffs to advise court as to status of discussions with Departments of Interior and Justice with respect to settlement possibilities. Hearing was held on March 8, 1973. Parties ordered to file briefs on certain legal points. Cases continuing.
4135	USA/Mobil and Equity	Complaint filed on July 10, 1972 wherein plaintiff seeks judgement to void, cancel, and quiet title to patented oil shale claims G. J. Nos. 1-24. Patent was issued in 1957, but Plaintiff contends that the issuing officer was not aware that the claims had been declared null and void in BLM contest proceedings, held in 1927. Hearing not scheduled. For discussion of issues, refer to Synthetic Fuels, September 1972, page 2-1. Motion to Dismiss denied December 29, 1972. At a hearing on August 22, 1973, ruling issued that Mobil is to prepare order specifying interrogatories it believes essential to its case. Government is searching for additional information to answer specific interrogatories. A motion for summary judgement to be heard January 3, 1974.

4139	USA/Eaton Shale, et al	Complaint filed on July 11, 1972 wherein Plaintiff seeks judgement to void a patent issued in 1951 for oil shale claims Gem Nos. 3-6, 9 and 10. Plaintiff cites a quitclaim deed dated January 12, 1929 from the then owner of the claims, De Beque Shale Oil Co., to the United States. Claims are located in an area controlled by Std. Oil Co. of California. Hearing not scheduled. For discussion of issues, see Synthetic Fuels, September 1972, page 2-1. Pre-trial conference, originally set for March 29, 1973 will be reset. Plaintiffs have until August 15, 1973 to file reply briefs. Oral arguments, if any, will be set at a later date. Motion by plaintiffs for Summary Judgement followed by objections, findings of fact, request for time extension. Case continuing.
4361	Amerada Hess/Sec'y, Interior	Complaint filed on September 26, 1972, wherein Plaintiff asks court to reverse decision of General Land Office Commissioner in BLM Contest 12790 (dated 1931) and to reverse Interior Board of Appeals ruling of June 28, 1972 involving rejection of unpatented mining claim ownership. Pre-trial conference originally set for February 20, 1973, will be reset later on an appropriate date. No action. Case continuing.
5276 and 5308	Zweifel, et al/USA	See discussion of issues under BLM Colorado Contest 441, Office of Hearings and Appeals, Department of the Interior.

BEFORE U. S. DISTRICT COURT IN WYOMING

Civil Action Number	Plaintiff/Defendant	Issues Involved & Status
5784	USA/Merle I. Zweifel and others	Complaint filed October 17, 1972 wherein USA seeks to void some 1500 unpatented claims staked for over 100 persons on various lands in Wyoming, including oil shale lands. No discovery, improper registration of claims and failure to locate in accordance with mining laws are charged. Court is still in process of receiving answers from absent defendants. Hearing was held November 23, 1973 on several motions. Trial set (non-jury) for December 5, 1973.

first of the year. In both cases, the Department of the Interior is seeking to cancel oil shale claims that were patented in the 1950's. One parcel of land in question is controlled by Mobil Oil Corp. and Equity Oil Co.; the other suit involves land controlled by Standard of California.

# # # #

CORSIM II WATER STUDY COMPLETED

In December 1969, the Board of the Colorado River Water Conservation District (CRWCD) retained the David E. Fleming Company of Denver to prepare a proposal for a computer simulation study of the Colorado and White River Basins in western Colorado. CRWCD's retention of Fleming came on the heels of a meeting with a group of oil companies with oil shale interests in the Piceance Basin.

One thing concerning both CRWCD and the oil companies at the time was the problem of conducting acceptable diligence work to maintain conditional water decrees under the recently approved Colorado Water Right Determination and Administration Act.

Another, and perhaps more basic, concern of the potential water users was over the availability of future water supplies for an oil shale industry. Since a study of the reliability of water supplies in the Colorado River Basin had never been undertaken, it was decided that a group study of water availability in the Colorado and White River Basins would serve both as due diligence and to identify the optimum scheme for developing water supplies for an oil shale industry.

With these goals in mind, Fleming prepared a proposal that was presented to industry representatives in January 1970. It described a two-phase study named CORSIM, an acronym for "Colorado River Simulation Model."

Phase I of the study was completed in April 1970 and served to identify, in more detail, the goals, objectives and methodology of Phase II. CORSIM I cost $25,000 and was supported by ten companies with interests in oil shale.

CORSIM II began almost immediately thereafter and by June 1970 had attracted a total of 15 participants as follow:

Atlantic Richfield Co.
Carter Oil Co.
Chevron Shale Oil Co.
Cities Service Oil Co.
City of Colorado Springs
City of Denver
Cleveland Cliffs Mining Co.
Colorado River Water Conservation Dist.
Getty Oil
Mobil Oil
Northern Colorado Water Conservancy Dist.
Public Service Co. of Colorado
Sohio Petroleum Co.
TOSCO
Union Oil of California

Activities through the summer of 1970 were reported in some detail in the March 1970 issue of Synthetic Fuels, page 1-10 and in the June 1970 issue, page 1-12. In addition, the proposal prepared by Fleming was reproduced in the Appendix of the March 1970 issue, page A-1.

Participants in Final Review of Fleming Data

All work on CORSIM II has been completed and is under final review by the 15 participating firms. Included in the documentation is a 500-year trace of synthetic virgin flows and temperature and precipitation values for the entire Colorado River (exclusive of the Gunnison) and White River basins of Western Colorado.

There are 974 virgin flow input points in the Colorado River basin and 101 in the White. Temperature and precipitation values, generated simultaneously with the virgin flows to preserve the correlation of data developed from the historic record, may be used to operate 16 separate climatological zones in the Colorado basin and six in the White. Alogrithms in the program, using the temperature and precipitation values to determine quantities of diversions and consumptive use for irrigation rights in specific time periods, were developed through modelling of selected areas in the two basins.

The data bank for this project contains all of the necessary parameters for about 2800 water rights, any of which may be operated during all or a part of each operation run. The acceptance runs, completed in July of this year, included a 30-year run on the entire Colorado basin using monthly time periods. The program is also capable of operation for quarterly and annual time periods.

The CORSIM program has the capability of operating each basin in its entirety and has provisions for determination of calls in accordance with the priority system and interstate compacts. Turn-around time between successive runs may be as little as two or three days, depending upon the modifications to the water rights package, operating rules and similar items.

When the CORSIM II study began in 1970, Fleming estimated the total cost as about $300,000. There have been no announcements of what the actual cost turned out to be.

Data Availability

Each of the original 15 participants in CORSIM II will receive a demonstrated model of the computer program, a complete file of input data for the two basins and complete documentation on the use and operation of system. The input data will be available to the participants only. The program, however, may be sold to other companies or organizations and is sufficiently flexible for application to other river basins.

For more information, one should contact the Colorado River Water Conservation District, P.O. Box 218, Glenwood Springs, Colorado 81601.

# # # #

TOSCO SEARCHING FOR WATER IN STORY GULCH

An agreement filed with the Rio Blanco County (Colorado) clerk and recorder in late August 1973 indicates a desire on the part of the Oil Shale Corporation (TOSCO) to develop a water supply in Story Gulch (near Piceance Creek) apparently for eventual transportation to and use on the Colony-controlled Dow fee property on the Middle Fork of Parachute Creek. The agreement, dated June 20, 1973 is between TOSCO and Weiland Ranch and Mercantile Company of Kremmling, Colorado.

The area covered by the agreement is shown on the map (Figure 1); the legal description of the land is: the W1/2NW1/4, SE1/4NW1/4, and SW1/4 of Section 5; the W1/2W1/2 of Section 8; and the N1/2NW1/4 of Section 17; all in Township 4 South, Range 95 West, 6th P.M.

"TOSCO," according to the agreement, "desires to drill core holes or wells on the above described lands and if water is found in sufficient quantity, to develop water wells thereon. In such event TOSCO further desires to file claim to and attempt to adjudicate for its benefit the right to take and use water from said wells and to lay a pipeline to transport such water from the wells to lands lying south thereof."

As can be seen in Figure 1, the southern edge of the Weiland property is roughly four miles north of the Colony fee land. The land in between is covered by Union unpatented claims. Further, there is no fee surface ownership on the Union claims between Story Gulch and Middle Parachute Creek.

Other salient points covered by the agreement are:

(1) TOSCO may drill core holes or water wells wherever they desire upon the subject land.

(2) TOSCO may, at its discretion, establish water wells as a results of such drilling at any time within five years of the date of the agreement which would be anytime before June 20, 1978.

(3) If TOSCO does establish water wells, it also has the right to construct one water pipeline across the Weiland property and to construct and maintain necessary electric power lines.

(4) If TOSCO develops water on the property, Weiland would have the right to use the water for its own

agricultural and domestic purposes at times when the water is neither needed nor being stored by TOSCO.

(5) TOSCO paid $500 for the privilege of drilling on the Weiland property and in addition will pay a $500-per-year well maintenance fee for each well established on the property as a results of TOSCO's drilling. Well maintenance fees would begin one year after a well is established.

# # # #

FLAT TOPS WILDERNESS PROPOSAL AFFECTS WATER AVAILABILITY IN PICEANCE BASIN

The proposed Flat Tops Wilderness Area, which would be established by U.S. Senate Bill S.702, is situated at the headwaters of the White River in Colorado. The ultimate size and shape of the wilderness area could affect the eventual use of water in the Piceance Creek Basin for oil shale development. The current controversy has resulted in an alliance among water development groups and citizen environmental organizations. Potential oil shale developers, while not disinterested, are standing by awaiting the final outcome.

The situation is this. Rocky Mountain Power Company (RMPC), a firm headed by Charles F. Brannan of Denver, has accumulated a number of conditional water decrees over the years that collectively represent a rather challenging and complex water development project in western Colorado. An integral part of this project is the proposed 132,000 acre-foot Meadows Reservoir on the South Fork of the White River some 50 miles upstream of the Piceance Creek Basin. Water from Meadows Reservoir would be diverted to the main stem of the Colorado River and thence to the Piceance Creek Basin; on its way from the White River drainage, the water would drive turbines at one or more proposed power plants.

The ultimate goal of this plan would be to provide industrial water for oil shale development in the vicinity and downstream of Rifle. Another possible use of the water (which

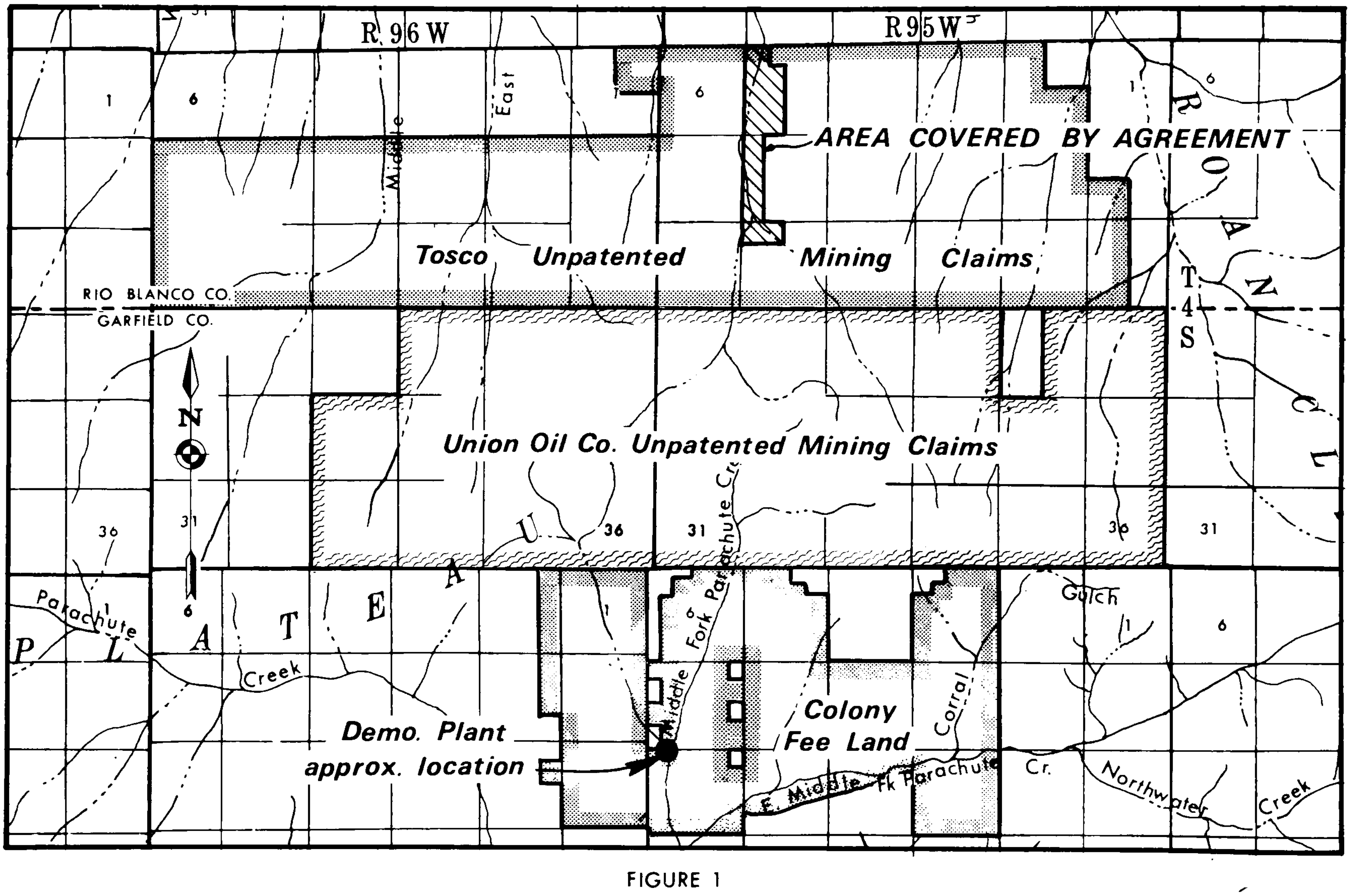


FIGURE 1
AREA COVERED BY TOSCO AGREEMENT

including the Meadows Reservoir and other units may total more than 200,000 AFY) is as replacement for water diverted to the eastern slope of Colorado to meet burgeoning municipal and industrial demands along the Front Range. It is the latter possibility that arouses the interest of water users on the Western Slope of Colorado.

As noted above, Meadows Reservoir is the key element in RMPC's proposed project; without that facility the project would not be feasible. But, the Meadows Reservoir site is at the center of the debate over the Flat Tops Wilderness Area; the question is, "should the site be included in the wilderness area designation or not?"

On October 31, 1973, the Colorado Water Conservation Board adopted a resolution requesting Congress to include the Meadows area in the Flat Tops Wilderness, a resolution officially supported by the Colorado River Water Conservation District, the Rio Blanco County Board of Commissioners, and the Colorado Rivers Council, a citizen organization. Further, Colorado's Congressional delegation is aware of the position taken by these organizations and appears to support that position. Thus, it is likely that the Flat Tops Wilderness Area will include the Meadows area on the South Fork of the White River.

Felix L. Sparks, Director of the Colorado Water Conservation Board, appraised Board members of his position in a memorandum dated October 24, 1973. Excerpts from that memorandum are as follow:

"The known oil shale deposits in the three-state region of Colorado, Utah and Wyoming contain nearly two trillion barrels of oil. About 80 percent of the known higher grade reserves are located in Colorado. The Piceance Creek deposits in the White River basin in Colorado are the most thoroughly explored of these deposits and are the richest known in oil content. Oil reserves in this area amount to more than one trillion barrels, about half the total shale oil reserves of the United States and third of those of the entire world as presently known.

"It now seems a certainty that a major oil shale industry will begin to develop in the Piceance Basin of Colorado within the relatively near future. It is anticipated that by some time in the 1980's a million barrel per day industry will be in operation. Such an operation will require significant quantities of water.

"The staff of this board believes that it would be a serious error for the state of Colorado to permit or encourage the waters of the White River to be imported into another area. In-basin use of the waters of the White River can be made below the boundaries of the proposed wilderness area. Because of their closer proximity to the Piceance basin, the waters of the South Fork of the White River are those most likely to be utilized in that basin. These waters can be diverted below the proposed wilderness area.

"The court testimony and statements of claim filed by the Rocky Mountain Power Company indicates that the company contemplates diverting approximately 110,000 acre-feet of water annually from the South Fork of the White River into the Colorado River for use in eastern Colorado by exchange. The company contemplates the total use of about 200,000 acre-feet of water from its project, with part of that water being available for sale to the oil shale industry. This amounts to a hundred percent of the flow of the South Fork of the White River at the diversion and storage points. The total average annual flow of the South Fork throughout its entire length and at a point just before entry into the White River is 205,000 acre-feet of water annually.

"In order to put an end to any plans to divert the water of the South Fork of the White River into the Colorado River basin, the staff continues to believe that the inclusion of the Meadows area in the proposed Flat Tops Wilderness area should be urged by this board as being in conformity with the best use of the waters of the White River in the state of Colorado, and in confirmity with the long continued efforts of this board to provide adequate water supplies for the oil shale industry."

The net effect on the use of water for oil shale development is that White River water will be developed and used in the White River Basin rather than being diverted to the Colorado River. It also, eliminates the possibility that some of the White River water might essentially be diverted for use on Colorado's eastern slope.

# # # #

CONFLICTING STATEMENTS ON THERMAL DECOMPOSITION OF DAWSONITE RESOLVED

In a paper entitled, "Thermal Decomposition of Dawsonite" (C. W. Higgins and T. E. Green, American Mineralogist, Vol. 58, 1973, pp. 548-550), the authors attempt to resolve conflicting statements in the literature on the thermal decomposition of dawsonite.

Previous investigations had proposed these conflicting equations and conditions.

(1) Savage, J. W. and D. Bailey, "Economic Potential of the New Sodium Minerals Found in the Green River Formation," Symposium on Chemical Engineering Approaches to Mineral Processing, Los Angeles, 1968:
These authors concluded that dawsonite decomposed at 370°C according to Equation (1).

$NaAl(OH)_2\,CO_3 \longrightarrow H_2O + CO_2 + NaAlO_2$ --- Eq. (1)

(2) Longhman, F. C., and G. T. See, "Dawsonite in the Great Coal Measures at Muswellbrook, NSW," American Mineralogist, Vol. 52, 1967, pp. 1216-1219:
These authors concluded that between 290 and 330°C the decomposition occurs according to Equation (2).

$2NaAl(OH)_2CO_3 \longrightarrow Na_2CO_3 + Al_2O_3 + 2H_2O + CO_2$ --- Eq. (2)

(3) Smith, J. W., and D. R. Johnson, in Proceedings of the Second Toronto Symposium on Thermal Analysis, 1967, pp. 95-116:
These authors agreed with Equation (2), but gave a reaction peak of 370°C.

The present authors, Higgins and Green, conclude that the thermal decomposition of dawsonite to H_2O, CO_2 and $NaAlO_2$ is a two step reaction. In the first step, the crystalline dawsonite decomposes between 300 and 375°C. In this step all the hydroxyl water and two thirds of the carbon dioxide are given off, leaving a residue which shows no crystalline structure. In the second, slower step, the balance of the carbon dioxide is released over the range of 360 to 650°C, producing crystalline sodium aluminate.

# # # #

FIRST DATA ON EITELITE DISCOVERY IN UTAH SHALE REPORTED

An apparently abundant deposit of mixed sodium carbonate minerals was noted in a core from the Mapco, Inc. Shrine Hospital #1 well, in Duchesne County, Utah in 1971. No information concering the assemblage of minerals encountered or their quantities was released then, but a recent paper by Adolf Pabst, "The Crystallography and Structure of Eitelite, $Na_2Mg\,(CO_3)_2$," which appeared in the American Mineralogist, Vol. 58, 1973, pages 211-217 states that a mineral called eitelite was noted in the core at depths from 4241 to 4249 feet. Its structure is rhombohedral and its density is 2.73. Except to note that eitelite occurs in abundance in this zone, no figures concerning grade were offered.

Eitelite is a soluble double salt of sodium and magnesium carbonates. As such, it represents a potential source for each of these compounds.

# # # #

BLACK TRONA BRINE OCCURRENCE DESCRIBED

Occurrence of organic trona brine in the Green River Basin of Wyoming is discussed in a paper "Black Trona Water, Green River Basin," by George F. Dana and John Ward Smith, published in the Twenty-Fifth Field Conference - 1973, Wyoming Geological Association Guide Book.

The report explains that black water is known to occur in 18 holes near Farson and Eden, Wyoming in the northern part of the Green River Basin. The black water reportedly consists of organic acids of high molecular weight, dissovled in a basic sodium carbonate solution. The organic acids can be precipitated by acidifying the carbonate brine. Generally, high artesian pressures on the black water cause relatively high volume flow of the black water at the surface. The high fluid pressure is thought to be caused by rock pressure (overburden load) on the brine trapped during deposition.

The paper reports that the organic content of the brine may reach 20 weight-percent although the average is nearer 10 percent. Soda ash obtainable from the trona brine may be as high as 7 weight-percent.

# # # #

USBM EVALUATES METHODS FOR DETERMINING NAHCOLITE AND DAWSONITE IN OIL SHALES

The specific quantitative determination of minerals in a rock is a more complex problem than determining the elemental chemical composition of the rock. The quantitative determination of a mineral content requires measuring some property that is unique and that is not masked or interferred with by other materials present.

The Bureau of Mines compared all of the known methods for determining the nahcolite and dawsonite mineral contents of oil shales and recommended the methods and combinations of methods they found most appropriate. Their means of comparing methods was described by C. W. Huggins, et al in "Evaluation of Methods for Determining Nahcolite and Dawsonite in Oil Shales," U.S. Bureau of Mines Report of Investigations 7781.

For determining nahcolite in oil shale, the method described by Smith and Young,* which is based on the selective solubility of sodium compounds, and a new method based on the weight of carbon dioxide produced by thermal decomposition are recommended. For determining dawsonite, x-ray diffraction and the Smith and Young method are recommended. For each mineral, the pair of methods cited should be utilized, rather than just one method. This avoids errors caused by the presence of other minerals whose presence in the sample may not be known but which may display the property used for one of the determinations.

*Smith, J. S., and N. B. Young, "Determination of Dawsonite and Nahcolite in Green River Oil Shale", USBM R. I. 7286, 1969

# # # #

THERMAL PROPERTIES OF GAYLUSSITE REPORTED

The mineral gaylussite, (chemical formula $Na_2CO_3 \cdot CaCO_3 \cdot 5H_2O$), is one of a suite of saline minerals which have been observed in the Green River oil shale formation. Gaylussite is little-known and is of minor importance, as its known occurrences are very small.

D. R. Johnson reported on the thermal properties of gaylussite in, "Gaylussite: Thermal Properties by Simultaneous Thermal Analysis," published in American Mineralogist, Vol. 58, 1973, pp. 778-784.

Gaylussite's thermal behavior evidently consists of three main features: (1) dehydration up to 250°C; (2) crystal transformation between 250°C and 500°C; and (3) melting and carbonate decomposition from 550°C to 1050°C.

# # # #

AUTHIGENIC SODIUM MINERALS IN GREEN RIVER FORMATION REVIEWED

The mentioning of minerals such as gaylussite, eitelite, etc. is somewhat confusing unless one understands that a rather amazing suite of sodium saline minerals occurs within the Green River formation. Some of these sodium minerals such as trona and halite occur in great abundance and are of obvious economic importance. Others such as nahcolite and dawsonite may be of economic importance if produced in conjunction with the production of oil or gas from oil shale.

Discussions of the sodium mineral occurrences may be found in the following references:

. Fahey, J. J., "Saline Minerals of the Green

River Formation", U.S. Geological Survey Professional Paper 405, 1962.

. Jaffe, F. C., "Geology and Mineralogy of the Oil Shales of the Green River Formation," Colorado School of Mines Mineral Industries Bulletin, Vol. 5, No. 3, May, 1962.

. "Sodium Mineral Occurrences in the Green River Formation," in Synthetic Fuels, Vol. 3, No. 1, March, 1966.

Summarizing the information available from these three reports, the authigenic (formed in place) sodium minerals which have been observed in the Green River oil shale formation are listed in Table 1.

# # # #

TABLE 1

AUTHIGENIC SODIUM MINERALS IN THE GREEN RIVER FORMATION

Mineral Name	Chemical Formula	Mole. Wt.	Sodium Content AS % Na	Sodium Content AS % Na_2CO_3
CARBONATES:				
Trona	$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$	226	30.5	70.4
**Eitelite	$Na_2Mg(CO_3)_2$			
*Dawsonite	$Na_3Al(CO_3)_3 \cdot 2Al(OH)_3$	432	16.0	36.9
*Burbankite	$Na_2(Ca, Sr, Ba, Ca)_4(CO_3)_5$			
**Shortite	$Na_2Ca_2(CO_3)_3$			
*Pirssonite	$Na_2Ca(CO_3)_2 \cdot 2H_2O$			
Gaylussite	$Na_2Ca(CO_3)_2 \cdot 5H_2O$			
**Norsethite	$BaMg(CO_3)_2$			
(New Unnamed)	$3NaHCO_3 \cdot Na_2CO_3$			
Nahcolite	$NaHCO_3$	84	27.4	63.1
Thermonatrite	$Na_2CO_3 \cdot H_2O$	124	37.1	85.5
CARBONATE-PHOSPHATES:				
**Bradleyite	$Na_3PO_4 \cdot MgCO_3$			
CARBONATE-CHLORIDES:				
Northupite	$Na_2CO_3 \cdot MgCO_3 \cdot NaCl$	248	27.8	42.7
SILICATES:				
Albite	$NaAlSi_3O_8$	262	8.8	
Analcite	$NaAlSi_2O_6 \cdot H_2O$			
Sepiolite	$H_6Mg_8Si_{12}O_{30}(OH)_{10} \cdot 8H_2O$			
**Loughlinite	$Na_2Mg_3Si_6O_{16} \cdot 8H_2O$			
*Labuntsovite	$(K, Ba, Na, Ca, Mn)\ (Ti, Nb)\ (Si, Al)_2(O, OH)_7H_2O$			
*Acmite	$Na_2O \cdot Fe_2O_3 \cdot 4SiO_2$			
*Elpidite	$Na_2ZrSi_6O_{15} \cdot 3H_2O$			
*Magnesioriebeckite (crocidolite), etc.	$Na_2(Mg, Fe)_3(Fe, Al)_2Si_8O_{22}(OH)_2$			
Feldspar	Variable Composition			
BOROSILICATES:				
**Reedmergnerite	$NaBSi_3O_8$			
Searlesite	$NaBSi_2O_6 \cdot H_2O$			
*Leucosphenite	$CaBaNa_3BTi_3Si_9O_{29}$			
HALIDES:				
**Neighborite	$NaMgF_3$			
Cryolite	Na_3AlF_6	210	32.8	
Halite	$NaCl$	58	39.7	

** Unique to the Green River Formation

* Known elsewhere only in igneous or metamorphic rocks.

FISCAL '74 RESEARCH PROGRAM SET BY LARAMIE ENERGY RESEARCH CENTER

The Laramie Energy Research Center (LERC) of the U. S. Bureau of Mines has finalized its petroleum, coal and oil shale research program for Fiscal Year 1974. A copy of the program is available for inspection at the Laramie Center, which is located on the campus of the University of Wyoming.

LERC devotes about 1/5 of its research efforts to conventional petroleum, about 3/5 to oil shale, and about 1/5 to coal. While the Bureau maintains energy research centers at Bartlesville, Grand Forks, Morgantown, Pittsburgh, Laramie and San Francisco, the Laramie Center conducts essentially all of the Bureau's oil shale research.

Level of Funding

For Fiscal Year 1974, LERC has an appropriation of about \$2.5 million which is approximately a 10 percent reduction from last year. The net decrease is the result of a reduction of about \$500,000 for oil shale research and an increase of about \$250,000 for coal research. In addition to appropriated funds, something over \$100,000 is contributed by other government agencies and industry in support of cooperative programs.

Research Program Notes

Last year an underground coal gasification program and a program for studying the in situ recovery of tar sands were initiated. These programs will continue this year and will require a reduction in work on oil shale, mainly in operation of the 150-ton retort, in determination of oil shale properties, and in oil shale environmental studies. Table 1 is a summary of the manpower involved in LERC's FY-1974 program.

# # # #

TABLE 1

LARAMIE ENERGY RESEARCH CENTER
Fiscal Year 1974 Program

	Engineers, Chemists & Technicians Involved
Petroleum Research	
In Situ Recovery From Deposits	
Lab. Evaluation of Methods	2.5
Design of Field Tests	2.5
Chemistry of Tar Sands Bitumens	4.4
Characterization of Heavy Oils	2.6
Asphalt Studies	4.0
Shale Oil Research	
Process Evaluation/Product Characteristics	9.0
Characteristics of Oil Shales	6.3
New Process Technology	5.5
Production of Clean Fuels	8.3
In Situ Retorting	12.2
In Situ Process Development	6.9
In Situ Retorting, Research	6.1
Coal Research	
Underground Coal Gasification	19.0

OIL SHALE GASIFICATION TESTS AT IGT PROMISE GREATER RECOVERY OF ORGANIC CARBON

The American Gas Association is sponsoring a study at the Institute of Gas Technology which has as its objective the determination of the technical and economic feasibility of producing high-Btu gas from oil shale. The estimated cost of the project, which began in 1972, is $330,000.

During the 1960's, AGA sponsored shale gasification work at IGT which indicated that, by gasification under pressure and in the presence of hydrogen, 80% of the shale's organic carbon could be converted to useful gaseous products. This compares with about 68% conversion of organic carbon by conventional retorting processes which produce liquids and gases.

Bench tests conducted by IGT during 1972 indicated that up to 97% of the organic carbon may be recovered. These recent tests, of small scale and utilizing a thermobalance reactor, enabled IGT to verify new but unpublished process concepts. IGT continued their tests with a 4-inch diameter, 24-foot high reactor. The results continued to be encouraging, but were limited to using shale of small particle size and failed to achieve proper temperature profiles.

Earlier this year IGT designed a 1-ton/hour process development unit which will be built by mid-1974 at IGT's facilities in Chicago. It will be used for final verification of the improved conversion efficiency indicated by the small-scale tests.

# # # #

USBM REPORT SUMMARIZES RESULTS OF TWO FIELD IN SITU TESTS

Beginning in late 1965 and continuing to the present time the Bureau of Mines Laramie Energy Research Center has conducted a series of tests related to in situ retorting of oil shale at a field test area located some seven miles west of the town of Rock Springs, Wyoming. Tests have been conducted at eight different sites in the field test area. The location of each of the sites is indicated on Figure 1, a drawing reproduced from USBM Report of Investigations 7783.

The type of experiments conducted at each site and the status of the experimental work are summarized in Table 1.

Results of in situ experiments conducted at Sites 4 and 7 in 1969 and 1970 respectively, are reported in the recently published USBM Report of Investigations 7783 entitled, "In Situ Retorting of Oil Shale: Results of Two Field Experiments".

Site 4 Test Results

The preliminary objective of the test at Site 4 where there is less than 100 feet of overburden was to create directed fractures. using electrolinking and hydraulic fracturing, for the purpose of producing a block of broken shale 20 feet thick and 25 feet square.

After fracturing tests were evaluated, the combustion phase of the in situ experiment began in April of 1969; propane and air were used to initiate combustion. The report describes in detail the progress and problems. Table 2 summarizes the calculated partial heat and material balance for the experiment.

Site 7 Test Results

The main objective of the Site 7 experiment was to study problems associated with ignition of oil shale broken by hydraulic fracturing and by detonation of explosives in wellbores. The combustion phase of the test, commenced in April of 1970, was terminated as soon as it was established that the oil shale had been successfully ignited.

A partial material balance and heat balance for the test at Site 7 is presented in Table 3.

Conclusions

The USBM report offers the following conclusions as a result of the experiments at Sites 4 and 7:

. A combustion zone can be established in a fractured oil shale body.

- The combustion zone can be maintained and moved through the shale be injected of air.

- The oil produced during in situ retorting of oil shale requires no special equipment for handling or recovery.

# # # #

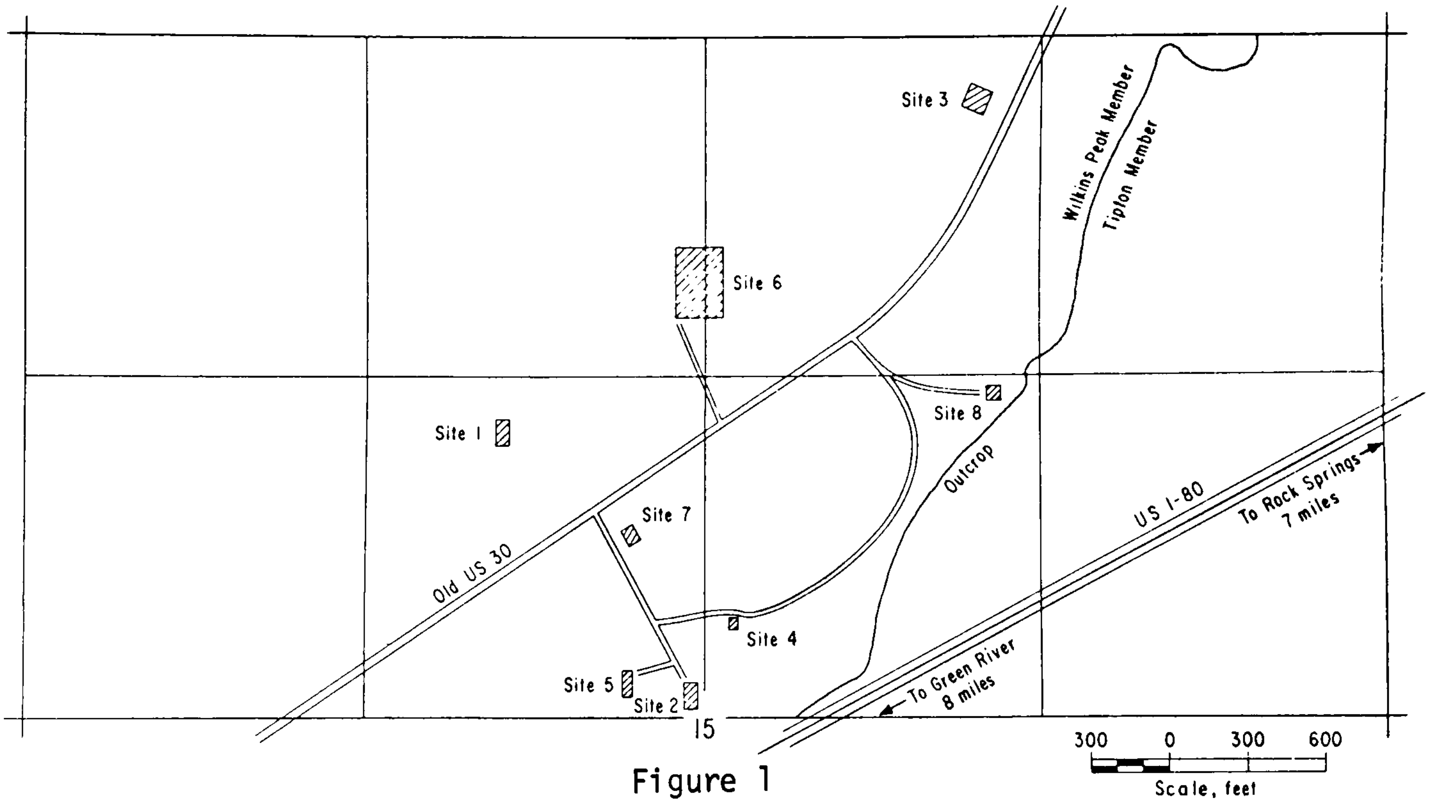


Figure 1

Rock Springs exploratory sites, sec 15, T 18 N, R 106 W.

TABLE 1

Types of Research at Rock Springs Sites 1-8

Site	Fracturing research			In situ experment	Steam injection experiment	Status
	Electrolinking	Hydraulic	Explosive			
1	X	X	X	-	-	Abandoned
2	X	-	X	-	X	Abandoned
3	-	-	X	-	-	Abandoned
4	X	X	X	X	-	Abandoned
5	-	X	X	-	-	Abandoned
6	-	X	X	X	-	In progress, 1973
7	-	X	X	X	-	Work halted
8	X	X	-	-	-	Abandoned

TABLE 2

PARTIAL MATERIAL AND HEAT BALANCES

SITE 4

Gas volumes, scf:	
Air injected (as measured by flow computers)	20,323,000
Oxygen injected (20,323,000) (0.209)	4,248,000
Oxygen unused	-738,000
Oxygen used	3,510,000
Oxygen used to burn propane (140.33 lb mole)(1,890 scf oxygen required/lb mole)	-265,000
Oxygen left to burn fuel in situ	3,245,000
Carbon dioxide produced	4,664,000
Carbon dioxide from burning propane (140.33 lb mole) (1,134 scf CO_2 produced/lb mole)	-159,000
Carbon dioxide from other sources	4,505,000
Carbon dioxide produced from burning fuel in situ (assume CH_2) (3,245,000)(2/3)	-2,163,000
Carbon dioxide remaining (assumed produced by carbonate decomposition)	2,342,000
Heat in, Btu:	
$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$ + 21,560 (Btu/lb C_3H_8)(6,188.5 lb C_3H_8) (21,560 Btu/lb)	134,000,000
$CH_2 + \frac{3}{2} O_2 \rightarrow CO_2 + H_2O$ + 20,300 (Btu/lb CH_2) (80,111 lb CH_2) (20,300 Btu/lb)	1,626,300,000
Air in at 100° F $\frac{(20{,}323{,}000\ \text{scf})(6.86\ \text{Btu/lb mole/° F})(100°\text{-}60°\ \text{F})}{378\ (\text{scf/lb mole})}$	14,800,000
Total	1,775,100,000
Heat out, Btu:	
Gas out at 100° F $\frac{(8{,}407{,}000\ \text{scf})(7.50\ \text{Btu/lb mole/° F})(100°\text{-}60°\ \text{F})}{378\ (\text{scf/lb mole})}$	6,670,000
Carbonate decomposition $\frac{(2{,}342{,}000\ \text{scf})(57{,}000\ \text{Btu/lb mole})}{378\ (\text{scf/lb mole})}$	353,200,000
Oil out (8,000 gal)(8.33)(0.969)(0.47)(100°-60° F)	1,210,000
Water out (8,000 gal)(8.33)(100°-60° F)	2,670,000
Total	363,750,000
Heat balance, Btu:	
Total heat in	1,775,100,000
Total heat out	-363,750,000
Total heat left	1,411,350,000

TABLE 3

PARTIAL MATERIAL AND HEAT BALANCES

SITE 7

Gas volumes, scf:	
Air injected (as measured)	909,500
Oxygen injected (909,500)(0.209)	190,100
Oxygen unused	93,900
Oxygen used	96,200
Oxygen used to burn propane (1,890 scf oxygen required/lb mole) (17 lb mole)	32,300
Oxygen left to burn fuel in situ	63,900
Carbon dioxide produced	92,000
Carbon dioxide from burning propane (17 lb mole) (1,134 scf CO_2 produced/lb mole)	-19,300
Carbon dioxide from other sources	72,700
Carbon dioxide produced from burning fuel in situ (assume CH_2)(63,900)(2/3)	42,600
Carbon dioxide remaining (assume produced by carbonate decomposition)	30,100
Heat in, Btu:	
$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$ + 21,560 (Btu/lb C_3H_8)(180 gal) (21,560 Btu/lb)(4.233 lb/gal)	16,500,000
$CH_2 + \frac{3}{2} O_2 \rightarrow CO_2 + H_2O$ + 20,300 (Btu/lb CH_2)	32,600,000
Air in at 100° F (909,500 scf)(6.95 Btu/lb mole) (1 lb mole/378 scf)(100°-60° F)	669,000
Total heat in	49,769,000
Heat out, Btu:	
Gases out at 100° F (774,000 scf)(7.29 Btu/lb mole) (1 lb mole/378 scf)(100°-60° F)	597,000
Carbonate decomposition $\frac{(30{,}100 \text{ scf})(57.000 \text{ Btu/lb mole})}{378 \text{ scf/lb mole}}$	4,539,000
Oil out (400 gal)(8.33)(0.899)(0.47)(100°-60° F)	56,000
Water out (400 gal)(8.33)(100°-60° F)	133,000
Total heat out	5,325,000
Heat balance, Btu:	
Total heat in	49,769,000
Total heat out	-5,325,000
Total heat left	44,444,000

WASHAKIE BASIN OIL SHALES DESCRIBED BY ROEHLER

The Washakie Basin oil shales are described and the in place shale oil resource is estimated in a paper by Henry W. Roehler published in the 1973 Wyoming Geological Association Guidebook. The paper is entitled "Mineral Resources in the Washakie Basin, Wyoming and Sand Wash Basin, Colorado." Roehler describes the occurrences of Washakie Basin oil shales (the outcrop of which is shown in Figure 1) in the Niland Tongue of the Wasatch and in the Luman Tongue and the Tipton Shale Member of the Green River Formation as mostly low grade, assaying less than 15 gallons per ton. The higher grade oil shales (assaying greater than 15 gallons per ton) exist, for the most part, in the lower portion of the Laney Member of the Green River Formation described and named by Roehler as the LaClede Bed.

Trudell, Roehler and Smith divide the LaClede Bed into nine different benches. The average shale oil yields for the benches of the LaClede Bed are shown in Table 1. Benches 8 and 9 have been partially to totally removed by post-LaClede Bed erosion at the U. S. Bureau of Mines Washakie Basin Corehole 1.

Estimated total shale oil resource in Washakie Basin ranges from 600 to 850 billion barrels. Roehler estimates, however, that only 8 to 10 billion barrels of shale oil exists in beds at least 10 feet thick and assaying 25 gallons or more per ton.

Resource extimates for the Sand Wash Basin are not given because of a lack of sufficient assay data.

# # # #

TABLE 1*

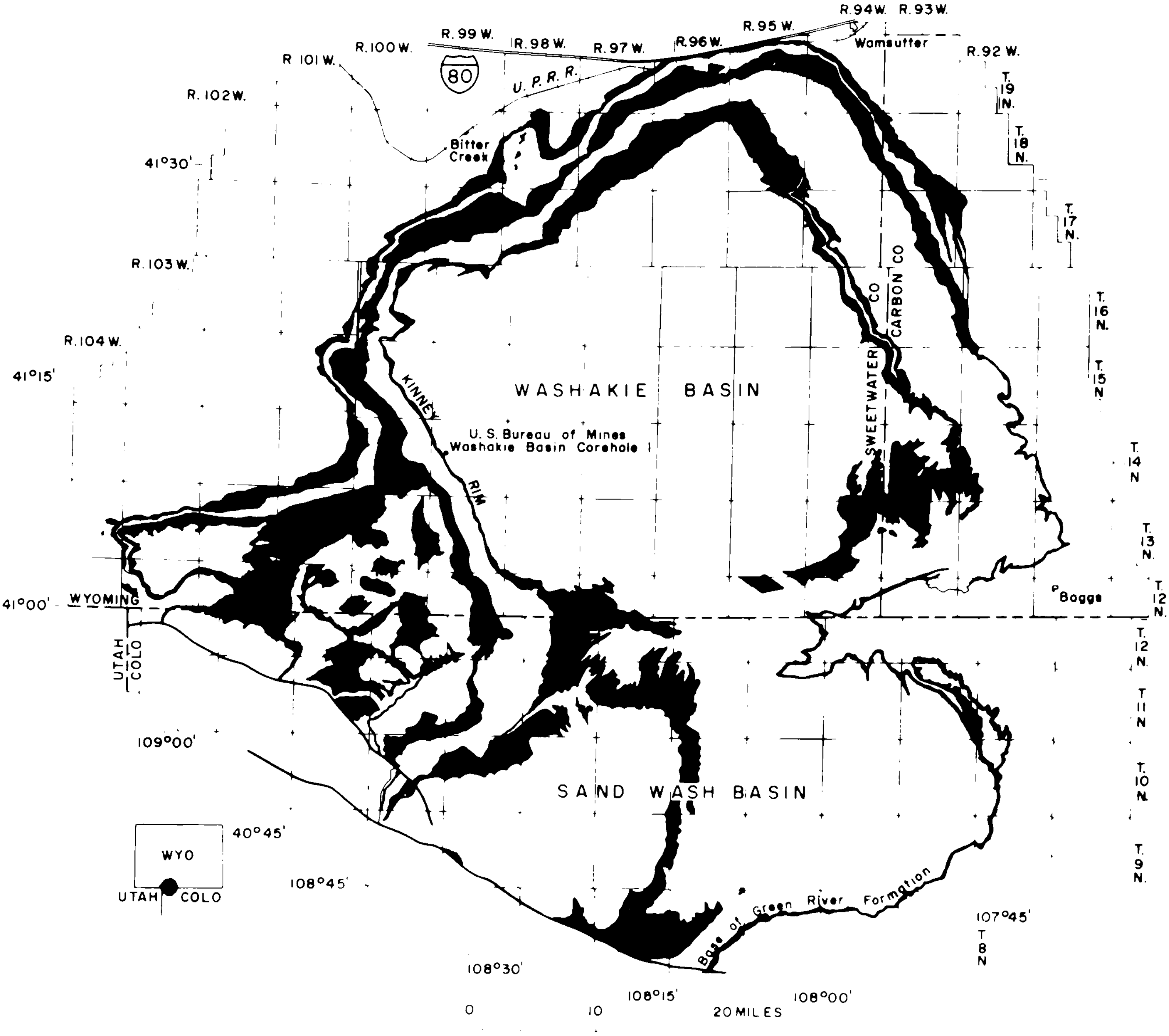
AVERAGE OIL YIELDS OF BENCHES IN
LaClede Bed, Laney Member, Green River Formation
(U.S.B.M. Washakie Basin Corehole 1)

Bench No.	Corehole Interval Depth-Ft.	Thickness Ft.	Average Yield GPT	Oil in Place MMBbl/sq. mile
9	Not present	-	-	-
8	Not complete	-	-	-
7	221.1-322.8	101.7	7.28	38.79
6	322.8-386.8	64.0	17.75	54.81
5	395.4-432.9	37.5	17.56	31.82
----------Buff marker in LaClede Bed----------				
4	495.2-509.2	14.0	22.81	14.86
3	512.6-547.4	34.8	18.45	30.83
2	552.9-593.0	40.1	10.59	21.65
1	628.0-649.1	21.1	7.34	8.11
----------Cathedral Bluffs Tongue of the Wasatch Formation----------				

*From 1973 Wyoming Geological Association Guidebook, p. 49.

FIGURE 1*

OIL SHALE OUTCROPS IN WASHAKIE & SAND WASH BASINS



*From 1973 Wyoming Geological Association Guidebook, page 52.

OCCIDENTAL IN SITU EXPERIMENT TERMED SUCCESSFUL

Occidental Petroleum Corporation announced in September that initial results from their in situ shale oil recovery experiment near DeBeque, Colorado are encouraging. This information was revealed by Donald E. Garrett in a presentation to the New York Society of Security Analysts. Garrett is executive vice president of Garrett Research and Development Company, the Occidental subsidiary conducting the experiment.

Oxy first announced the experiment in late 1972 and initiated field operations in January 1973. The in situ scheme is described in U.S. patent 3,661,423. Essentially, an oil shale retort is created underground by first removing shale (by conventional room and pillar mining) from beneath a specified area, then collapsing the roof of the resultant mine thru the use of conventional explosives. The rubble is then ignited by injecting propane or some other fuel and shale oil is recovered through wells to the surface. Shale oil is collected in the rubble pile thru a pipe network placed on the mine floor before the roof is collapsed. According to the patent, mine pillars would be 17-1/2 feet square and rooms would be 25 feet square. The room height is not mentioned.

The principal advantage of Oxy's scheme is obviously the creation of permeability. Inducing permeability from the surface has been the major problem experienced by other in situ operations over the years. Since Oxy's scheme is based on removing shale to create the necessary permeability, their process may not be, technically speaking, an in situ process. Nonetheless, the problems associated with surface disposal of spent shale would be substantially reduced by Oxy's process.

It would appear that Oxy can use one of two approaches in employing their process. First, they could mine the lower portion of a high-grade oil shale zone. This would present the problem of what to do with the mined oil shale that is brought to the surface. It would not seem prudent to waste this material, since for the relatively small additional cost of crushing, the shale could be fed to a surface retort.

A second approach that could conceivably be taken by Oxy is to mine a relatively barren zone of shale immediately beneath a high-grade oil shale zone. Any shale brought to the surface in this manner may thus truly be classified as waste material and disposed of accordingly. This approach, however, is a rather expensive method of creating waste rock.

The ultimate success of Oxy's scheme is, of course, dependent on the efficiency of recovering shale oil from the underground rubble pile. The initial results according to Garrett have been most encouraging. The rubble zone was ignited in late February and by early September, recovery had reached 25 to 30 barrels per day. Further, Garrett indicated that yields have exceeded 50 percent. By mid-September, the rubble zone was about half-fired, although the areal extent of the experiment is unknown.

The experiment is being conducted on private oil shale land controlled by D. A. Shale Inc. Occidental has a 3-year lease and option agreement with D. A. Shale whereby Oxy agrees to spend $1 million to develop the in situ process. The agreement was more fully described in the March 1973 issue of <u>Synthetic Fuels</u>, page 2-20.

# # # #

PARAHO ADDS SIX MORE PARTICIPANTS

Six companies have joined the Paraho Development Corporation oil shale retorting project since September 1, 1973. Mobil, Sun, Webb Resources, Texaco, ARCO and Phillips, in that order, joined the program at a cost of $500,000 each in the past three months, giving the program a total of 15 participants, the goal announced by Paraho officials earlier this year. Webb Resources heads a group that also includes Gary Operating Company of Denver and Jerry Chambers, an independent oil producer from Denver. The current list of participants is as follows:

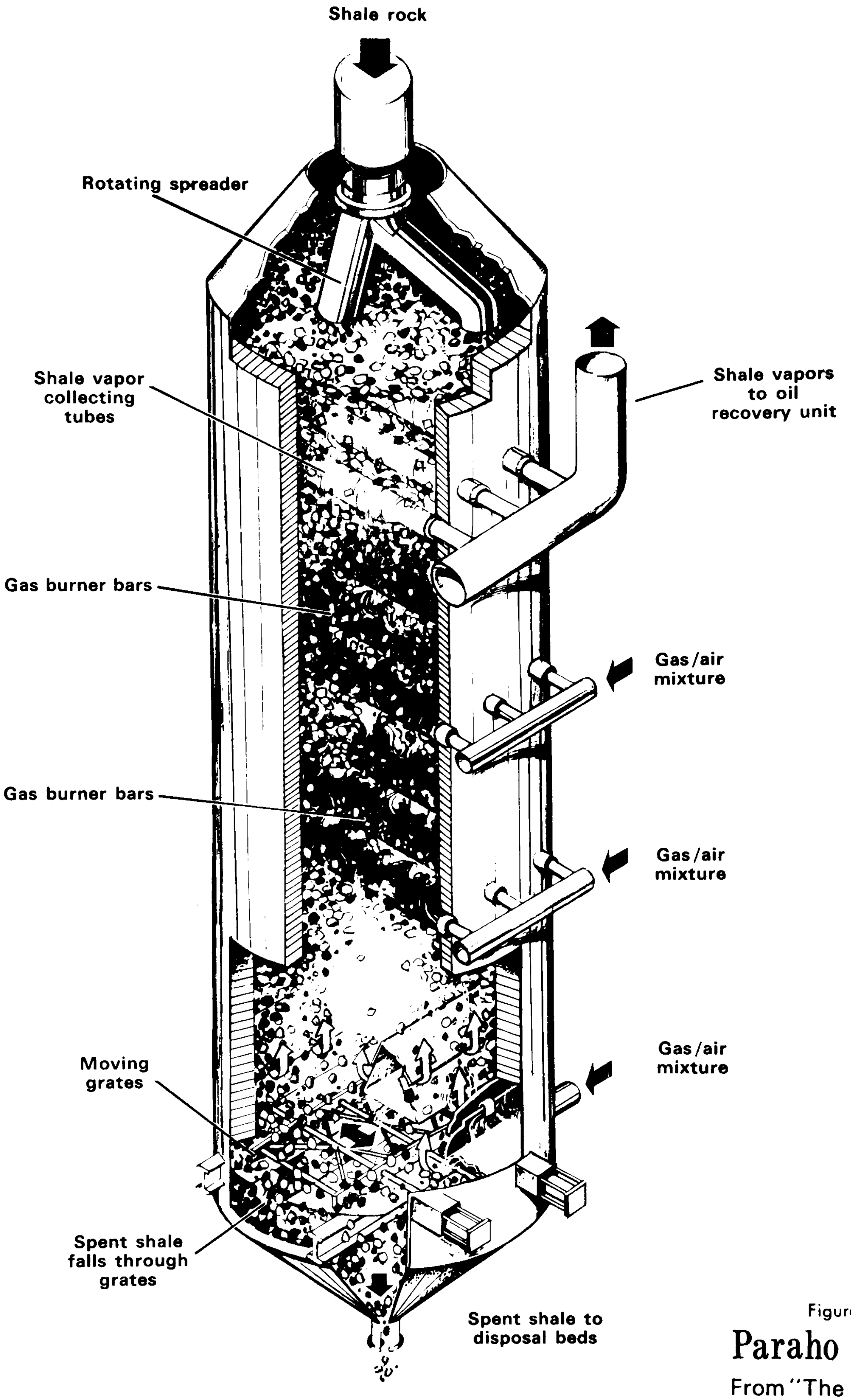


Figure 1

Paraho Retort

From "The Sohioan"

A. G. McKee Co.
ARCO
Carter Oil Co.
Cleveland Cliffs
Gulf Mineral Resources
Kerr McGee
Mobil Research & Development
Phillips
Shell
Sohio
Southern Calif. Edison Co.
Standard Oil (Indiana)
Sun
Texaco
Webb Resources

Paraho first sought industry support for the research program in May of this year, shortly after reaching agreement with the Department of the Interior for leasing portions of the Anvil Points oil shale demonstration facility near Rifle. (See June 1973 Synthetic Fuels, page 2-15).

Paraho hopes to take over the Anvil Points facility before the end of December and begin construction for their research program during the early months of 1974. Currently, Interior is conducting an inventory of equipment and materials at Anvil Points which is necessary before the lease can be actuated.

The Fall 1973 issue of The Sohioan, a magazine published by the Standard Oil Company (Ohio), notes that engineering and preliminary paper work will be completed in a few weeks and that construction of an 8-1/2 foot inside diameter vertical kiln will require five or six months. Initial test runs could thus be conducted in mid-1974. The Sohioan article includes an artist's conception of the Paraho retort. That drawing is reproduced as Figure 1 on page 2-24.

# # # #

COLONY PUBLISHES ENVIRONMENTAL STUDY OF PROPOSED PRODUCTS PIPELINE

Colony Development Operation has published an environmental study of their proposed oil products pipeline from Parachute Creek to the Aneth area in southeastern Utah. The study was conducted by Utah Environmental and Agricultural Consultants.

Colony also submitted a letter of intent to BLM regarding construction of the pipeline but has not filed a formal application for the necessary right-of-way permits. Thus, specifications of the pipeline such as capacity and estimated cost are not publicly available. It is known from the environmental study, however, that the proposed route extends a distance of 180 miles and follows an existing El Paso Natural Gas Co. pipeline for approximately 130 miles. See Figure 1 for the approximate route. From Aneth, pipelines lead east and west which could take the shale oil to Los Angeles, Houston, or to East St. Louis or Chicago via a connection at Jal, New Mexico.

According to the environmental analysis, the final route selected for the pipeline was one which will cause the least overall environmental impact. The proposed line crosses vegetation types and soils which are either quite low in productive potential or the impact can be easily mitigated, the study states. Furthermore, the study notes, except for the Roan Plateau there is a general paucity of wildlife.

Colony Presents Road Request

In November, Colony officials presented to the Colorado Highway Commission a request for a $4.6 million, 10.8-mile state highway extension up Parachute Creek. The road would go from the town of Grand Valley to the Colony Development Operation boundary near the Union Oil Co. plant site. Colony would build another 10 miles of road from there to the proposed shale oil plant atop the Roan Plateau. The request seeks construction of the road in 1975.

After the Colony request was presented, the Glenwood Springs City Council unanimously passed a resolution calling for the protection of public funds available to cities and counties from dilution by oil shale and other industries. The resolution calls for some government agency, preferably the Region 11 Council of Governments (COG), to take the responsibility for a comprehensive plan to serve the energy-development industry. Commenting on the resolution, Glenwood Springs City Manager Roy Rainey said, "If we expect orderly development of the resources we have, we're going to have to begin immediately to

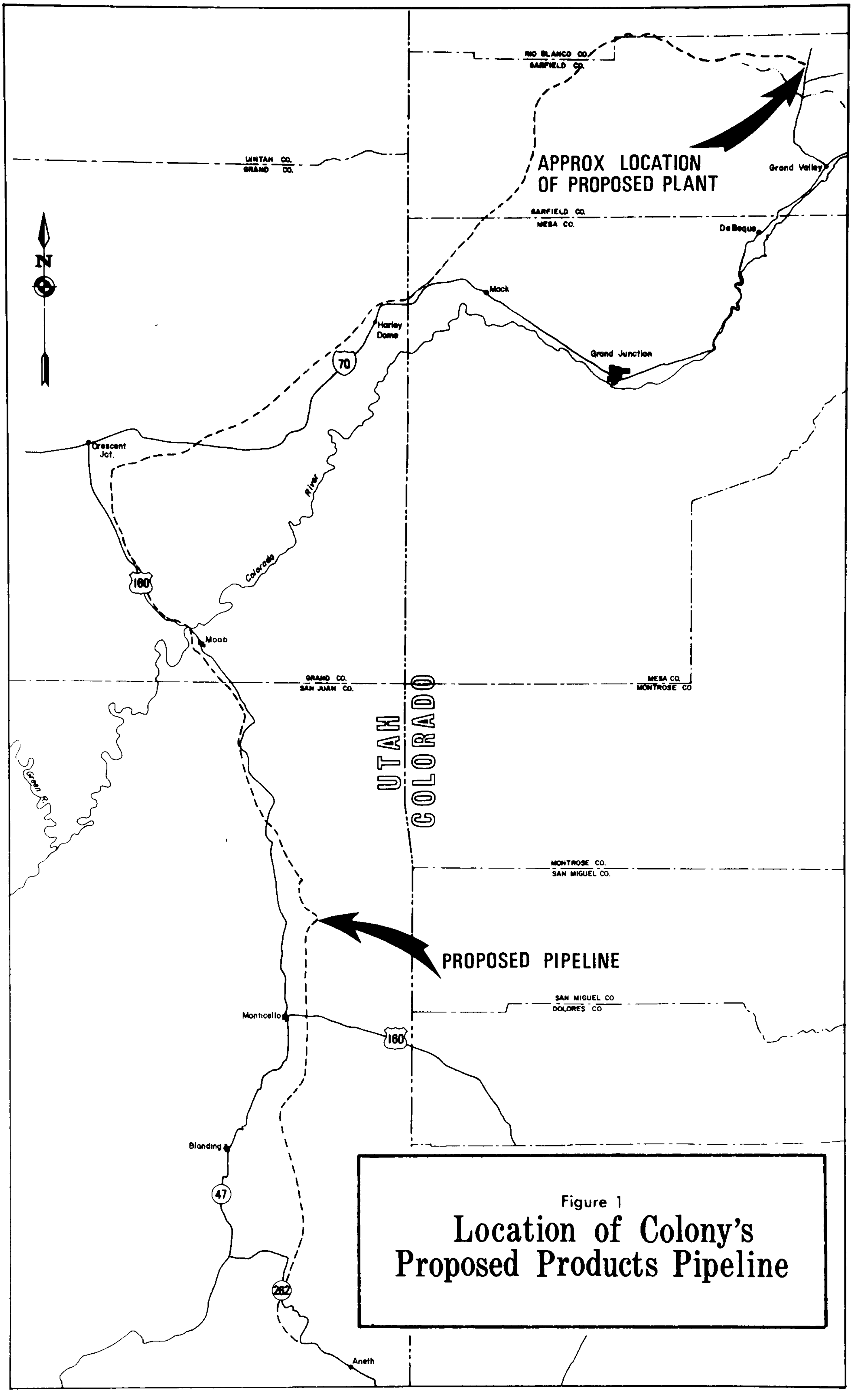


Figure 1
Location of Colony's Proposed Products Pipeline

resist the dilution of the public funds available to Colorado West citizens by the oil shale industry."

# # # #

CLUB 20 PROPOSES INTERDISCIPLINARY ANALYSIS OF COLORADO WEST'S ENERGY RESOURCES

Club 20, an organization dedicated to promoting the overall socio-economic development of western Colorado, recently submitted a proposal to the National Science Foundation (NSF) to finance an interdisciplinary analysis and evaluation of the environmental and economic "trade-offs" associated with the development of energy resources on Colorado's Western Slope. The club has requested $414,000 for a two-year study as part of the RANN program (Resources Applied to National Needs).

The justification and need for the proposed study, Club 20 states, was summarized in a recent report entitled "Energy, Resources/Uses in Colorado." The report states:

> "One of the toughest challenges facing Colorado is America's energy crunch. Because the state has a treasure house of energy resources, its destiny is inevitably tied to the solution of this critical national program -- Colorado sits in a delicate position."

Development of these energy resources -- coal, natural gas, uranium and oil shale -- poses a real dilemma because the 44,000 square miles of western Colorado where they are concentrated, also encompasses the spectacular and scenic Rocky Mountains, 65 percent of which is publicly owned. "A dichotomy between the energy resource developers and environmentalists is thus assured," the proposal states. Adding to the dilemma is the fact that over four million acres of wilderness have been proposed in Colorado.

"Generally speaking, the proposal continues, "the bulk of these individuals who call for no development of public lands do not reside in nor are they dependent for their economic livelihood on the area where they are attempting to maintain the status quo." Furthermore, the current dispute between environmentalists and basic resource developers is predicated more on emotional arguments than on prognostic analysis and evaluation of facts, impacts, economic consequences of decisions etc. Therefore, the proposal suggests analysis of the following societal problems:

. What is the potential impact and consequences on the national economy if the energy resource base of Colorado West is precluded from development?

. What will the socio-economic future of Colorado West be if the energy resource base is not developed?

. What types, what magnitude, where and what permanency of environmental degradation will be associated with development of these resources?

. How much land area will be required to serve how many people from what socio-economic class?

. Who and how many will suffer from various combinations of energy resource development versus wilderness designation?

The proposal has been submitted to the NSF in preliminary form to "try out the concept." If NSF accepts the preliminary proposal, a formal and expanded application will be submitted later.

# # # #

OIL SHALE LEASING BY INTERIOR TO BEGIN IN JANUARY 1974

Interior Secretary Rogers Morton announced on November 28, 1973 his decision to proceed with the prototype oil shale leasing program and that the first lease sale would be held on January 8, 1974 in Denver. First announced by Morton on June 29, 1971,* the program has seen nearly 2-1/2 years of work, at an inestimable cost, devoted primarily to satisfying the requirements of the National Environmental Policy Act of 1969.

On November 30, Interior published the following documents as Part III of the Federal Register, 38FR 33185-33199:

(1) Modification of Oil Shale Withdrawal
(2) Oil Shale Leases, Notice of Sale
(3) Oil Shale Lease, including Environmental Stipulations

Those documents are reproduced in the Appendix beginning on page A-90.

Lawsuit Still a Possibility

The final environmental impact statement for the leasing program was released on August 30, 1973. At that time, Morton indicated he would wait at least 60 days before announcing his final decision concerning continuation or abandonment of the program. His decision could, therefore, have been announced as early as November 1, except that additional comments on the program were submitted by environmental organizations during the week or ten days following October 25. Thus it is likely that Interior postponed the announcement until the last minute comments were considered, although Interior was under no legal responsibility to do so.

Most, if not all, of the late comments on the program asked for further study and consideration before the program proceeds. Some asked that the program not be implemented under any circumstances; still others asked for the withdrawal of the Colorado tracts from the leasing plans.

Based on the number of last minute criticisms, there appears to be a better-than-even chance that a lawsuit to stop the lease sales will be filed by one or a group of citizen environmental organizations. Postponement of the first scheduled sale is thus a possibility.

It is obvious that the 2-1/2-year preparation of a 6-volume, 3200-page environmental statement has not allayed the fears of environmental groups -- they are still opposed to oil shale development for basically the same reasons given before the current program was initiated.

Decision Statement

In announcing his decision, Secretary Morton released a 4-page decision statement that summarizes his reasons for proceeding with the program. Excerpts from that statement are as follow:

"I have decided it is in the national interest to approve the Prototype Oil Shale Leasing Program, and offer for lease six tracts, two each in Colorado, Utah, and Wyoming, for oil shale development. The first sale will be held on January 8, 1974. I have made this decision after lengthy and serious considerations of the many issues and alternatives involved. I recognize that estimates of future demand are uncertain, but our best estimates, and the course of recent events affecting our energy supply, leave no doubt that in the years ahead we must place greater reliance on new domestic sources of petroleum. The high risks and many uncertainties that attend dependence on foreign supplies of energy make it imperative that we explore expeditiously all of our promising alternative energy supplies. The leasing program I have approved will encourage oil shale development and allow us to learn whether our 600 billion barrel shale oil reserve can be developed at acceptable economic and envrionmental costs.

*Articles concerning the leasing program have appeared in the September 1971 and each subsequent issue of Synthetic Fuels.

"Prototype oil shale development will incur some environmental costs and risks, but I am satisfied, on the basis of the analysis in our Final Environmental Statement, that we have developed rigorous and comprehensive environmental controls, and that the potential benefits outweigh the unavoidable costs and risks involved.

"In analyzing whether the objectives and features of the prototype oil shale leasing program will meet the twin tests of expanding energy production and providing environmental protection, I have explored the following questions and considered several possible variations of the program:

(1) Is the prototype program well designed in the light of the need to develop new energy supplies?

(2) Are the expected environmental impacts of the program acceptable?

(3) Is the program economically attractive enough so that timely development will occur?

"My analysis of these questions has led me to the following conclusions;

(1) Responsiveness to Energy Needs: Oil shale is a tremendous reserve of oil--one of the world's largest. However, it will be some years before the technology to economically produce large quantities of shale oil is available. In order to expedite this development, and provide an opportunity to study the environmental impacts of oil shale mining and extraction, some of the rich public shale land must be made available. We cannot depend on shale oil to supply our immediate needs, but now is the time to prepare for good environmental management of shale development in the future.

(2) Acceptability of Environmental Impacts: In my mind, as well as in the minds of many interested citizens, the most troublesome impacts of oil shale development are those that might occur from the growth of a major industry, employing thousands of workers and disturbing large areas of the oil shale country. No decision to set such growth in motion, beyond the effects of the lease of these six sites, has been made, or will be made until the impacts of commercial scale production can be assessed. Controls devised for the six prototype sites are the most detailed and comprehensive ever included in a mineral lease of the Department of the Interior. Even so, some impacts on the air, water, land, wildlife, and the remote and primitive quality of the area on and around the prototype sites are unavoidable. I believe the risks of major damage to be small, and the overall impacts acceptable. One means of reducing the environmental impacts of the prototype program, which I have considered, is leasing fewer than six sites. Since the ecology and geology vary among the tracts, and we wish to provide an opportunity to test alternative methods, I believe we should lease six sites, and not require the use of any one method or technology. The authority to approve detailed development plans and to conduct close surveillance of the lessees' operations which the Department has retained will give us both assurance of environmental protection and needed experience in managing oil shale production. Without the information we can gain from the prototype program little rational energy or environmental planning for the future of oil shale will be possible

(3) Economic Attractiveness: Private sector participation in the design of the program, the provisions incorporated in the lease to encourage timely development, and of course, the rapidly rising price of crude oil, all suggest convincingly that there is high interest in the prototype program.

But uncertainty in estimates about the cost of production of shale oil is very great, and for some technologies, estimates are quite pessimistic. The prototype offering of six sites was planned to allow trial of alternate methods of extraction.

However, the best incentive we have to offer is the availability, at a fair return to the public, of the rich shale lands in the public domain. Therefore, I do not believe that under present circumstances a subsidy is either wise or necessary for this program.

"The Department is committed to withhold further leasing of public oil shale lands (which comprise 80% of the known reserves) until the environmental effects of these prototype leases are better known. A new Environmental Impact Statement will be completed before any further leasing takes place, though the Department does not plan to issue any further Environmental Statements on any phase of the Prototype Program.

"I am convinced that it is in the national interest to proceed with leasing of these prototype sites. The objectives of this program have the support of the States and of industry. This program is dedicated to achieving a proper balance of the Nation's concern for economic use of our resources and protection of the environment. Accordingly, I have decided to proceed with implementation of the Prototype Oil Shale Leasing Program."

Sale Schedule

Announcement of the sale of each tract will be made by publication of a separate notice in the Federal Register and in a newspaper of general circulation in the state and county in which the offered lands are located, setting forth the date, time, place, and conditions of the sale.

Interior will hold one sale per month during the first six months of 1974 which is a slight departure from the previously announced intention to hold one sale every two weeks. No particular significance is attached to this change. The sales will be held according to the following schedule:

Date	Tract	Sale Location
Jan. 8	C-a	Denver
Feb. 12	C-b	Denver
Mar. 12	U-a	Salt Lake City
Apr. 9	U-b	Salt Lake City
May 13	W-a	Cheyenne
June 11	W-b	Cheyenne

Bidding Procedures

Leases will be offered by sealed bonus bidding. A lease will be issued only to the qualified bidder submitting the highest amount per acre as a bonus for the privilege of leasing the lands. As will be discussed below, a preliminary development plan is still required, but will not be a determining factor in selecting the successful bidder.

No specific form of bid is required, but all bids must identify the lease sale and must show the total amount bid and the amount bid per acre. The amount submitted with the bid is to consist of one-fifth of the bonus bid plus the first year's annual rental of 50¢ per acre or fraction thereof. Other bidding procedures are described in the Appendix, page A-90.

Bids will be opened at the place, date and time announced for each of the respective sales, but the successful bidder will not be immediately identified. The amount of bids will, however, be publicly announced when opened. There is no indication of how soon after bid opening Interior will announce the successful bidder. Further, Interior reserves the right to reject any or all bids if none is determined to be adequate. Minimum acceptable bids for each tract have not and will not be defined by Interior prior to the lease sales.

Interior's notice in the Federal Register specifically notes that not more than one lease will be granted to any one person, association or corporation. It should be noted, however, that an opinion by Interior Solicitor Melich in 1971 (serial number M-36843) expressly states that "...a person, association, or corporation may hold indirect interests in oil shale leases issued under the Mineral Leasing Act of 1920...so long as the aggregate chargeable interests, direct and indirect, do not exceed 5120 acres." That opinion was reproduced in the December 1971 issue of Synthetic Fuels, page A-71.

Preliminary Development Plan

Within forty-eight hours after being informed that his bid has been accepted and that a lease will be issued to him, the successful bidder must transmit a preliminary development plan, in duplicate, to the officer conducting the lease sale. This plan will be made public upon issuance of the lease, and, therefore, confidential information relative to the lessee's operations should not be included in the submission. Confidential information necessary to describe the preliminary development plan should be submitted in the same manner, but under separate cover. The submission or acceptance of these plans will not be binding on the lessee or lessor and will not authorize any action by the lessee, but the plan is required for the lessor's guidance in establishing initial supervision of the lessee's activities. The preliminary development plan should include the method of development, the proposed location of on and off-site facilities, the schedule for development, and monitoring programs to determine environmental criteria.

The fact that a preliminary development plan need not be submitted with a bid represents another slight departure from the procedure announced on August 30, 1973 when the final environmental statement was released. The procedure to be used now means that the successful bidder will be selected solely on the basis of the amount of the bonus bid. It also eliminates any need on the part of Interior to make what would had to have been a subjective analysis of several competing development plans. Under the adopted procedure, Interior will not even see plans prepared by unsuccessful bidders. There is, however, no specific procedure identified for dealing with the potential situation where the successful bidder's preliminary plan is adjudged inadequate. Interior apparently does not expect this to occur.

The preliminary development plan concept is unique to the oil shale leasing program. Interior likely does not expect a great deal of detail to be shown in the plan. The reason should be obvious to anyone, but is often overlooked by critics of the program, i.e. a company, who has had limited access to a tract of land for exploratory drilling only, is simply not willing to make the expenditures nor do they have the information necessary to prepare a plan with much detail, especially since they have no assurance of acquiring the lease in the first place. We suspect that if Interior could start over, they might eliminate the preliminary plan concept.

That the preliminary plan of the successful bidder will be made public upon lease issuance should come as no surprise to industry. Critics will be "shocked" that the plans will include, in their opinion, "so little information." At the same time, however, critics should recognize that before development can begin on a tract, a detailed plan will be submitted to and approved by Interior.

Thus Interior has taken a practical view of the preliminary development plan. Its principal value will be in identifying publicly those additional lands that may be necessary to develop a leased tract in an orderly manner.

Minimum Royalty

A slightly better definition of minimum royalties is provided in the November 30th Notice in the Federal Register than was given at the time the final environmental statement was released in August. As announced in August minimum royalty begins in the sixth lease year and is based on a theoretical production rate which is related to estimated recoverable reserves on a given tract. Table 1 is a summary of royalty and production rates for each tract. The production rate for each tract increases on a straight line basis between the 6th and 15th lease years.

Table 2 lists dollar amounts of minimum royalties for each tract during the 6th thru the 20th lease years. The amounts shown reflect an annual credit for rental of 50¢ per acre. Table 2 is essentially the same as one presented in the September 1973 issue of Synthetic Fuels, page 17, except that the amounts shown have been revised slightly to conform to the newly established minimum royalty production rates for each tract.

It should be noted that the royalty rate of 12¢ per ton of 30 gpt shale will be adjusted each year (beginning with the second lease year) in relation to the change in the combined average value of crude oil and shale oil in the states of Colorado, Wyoming and Utah between the current and preceding lease year. Worthy of mention is the fact that crude oil prices have risen sharply in the past six months alone. If the first lease sale had been held one year ago, as originally scheduled, royalty rates would likely

TABLE 1

ROYALTY & MINIMUM PRODUCTION RATES

Tract	Royalty Basis: Shale Grade GPT	Royalty Basis: ¢ Per Ton	Production Rate 1000 Tons/yr.: 6th Year	Production Rate 1000 Tons/yr.: 15th Year
C-a	30	12	1,130	11,300
C-b	30	12	616	6,160
U-a	30	12	208	2,080
U-b	30	12	227	2,270
W-a	20	4	215	2,150
W-b	20	4	214	2,140

have increased significantly already. As royalty is now structured, a big chunk of the price increase may already have occurred without any effect on royalty.

It should also be noted that during any lease year, a lessee will not know precisely what royalty rate is effective for that year until the average crude value is computed at the end of the calendar year.

Changes in Lease Form

Since publication of the final environmental statement in August, there have been a number of minor wording changes in the lease. There have also been some substantive changes and additions that are worthy of mention. These are described below by Section number. The final version of the lease, which appears in the November 30 Federal Register, is reproduced in its entirety in the Appendix beginning on page A-90.

Section 1: Definitions -- A definition of commercial quantities" has been added where none appeared before, i.e., "commercial quantities" means quantities sufficient to provide a return after all variable costs of production have been met.

Section 2: Grant to Lessee -- Previously, the lessee was granted the right and privilege to...mine...on the leased lands. In the final lease, mining is specifically qualified to allow mining "by underground or surface means."

TABLE 2

MINIMUM ANNUAL ROYALTY

IN LIEU OF ROYALTY ON ACTUAL PRODUCTION*

TRACT

Year	C-a	C-b	U-a	U-b	W-a	W-b
0-5	0	0	0	0	0	0
6	$ 133,055	$ 71,373	$ 22,400	$ 24,680	$ 6,004	$ 6,018
7	268,655	145,293	47,360	51,920	14,644	14,578
8	404,255	219,213	72,320	79,160	23,244	23,138
9	539,855	293,133	97,280	106,400	31,844	31,698
10	675,455	367,053	122,240	133,640	40,444	40,258
11	811,055	440,973	147,200	160,880	49,044	48,818
12	946,655	514,833	172,160	188,120	57,644	57,378
13	1,082,255	588,813	197,120	215,360	66,244	65,938
14	1,217,855	662,733	222,080	242,600	74,844	74,498
15-20	1,353,455	736,653	247,040	269,840	83,444	83,058
Total (20 yrs.)	$14,199,825	$7,723,335	$2,582,400	$2,821,800	$864,660	$860,670

*Figures reflect credit of 50¢/acre annual rental

Section 12: Water Rights -- This will likely prove to be the most controversial clause in the lease. Where no such clause existed in the August 30 version, the following has been added to the final lease form:

"All water rights developed by the Lessee through operations on the Leased Lands shall immediately become the property of the Lessor. As long as the lease continues, the Lessee shall have the right to use those water rights free of charge for activities under the lease."

Section 33: Protection of (Lessee's) Proprietary Information -- Section 33 is entirely new. No such protection was afforded the Lessee in the August 30 version of the lease. Because the section is lengthy, the reader is referred to the lease form in the Appendix. The inclusion of a new Section 33 means that the previously numbered Sections 33 and 34 are now Sections 34 and 35, respectively.

Section 34: Lessee's Liability to Lessor -- In the August 30 lease, the lessee was held liable to the lessor for any damage suffered by the United States...arising from activities conducted pursuant to the lease. This has been modified to limit lessee's liability to damage arising from the <u>lessee's</u> activities.

Also, the following clause was added:

"In any case where liability without fault is imposed on the Lessee pursuant to this section, and the damages involved were caused by the action of a third party, the rules of subrogation shall apply in accordance with the law of the jurisdiction where the damage occurred."

Previously no such clause was included.

<u>Changes in Environmental Stipulations</u>

Section 1 of the environmental stipulations was changed so that any revisions in or amendments to the stipulations must be by the mutual consent of the USGS Mining Supervisor, the lessee and the Bureau of Land Management District Manager. Previously, changes required the consent of only the lessee and Mining Supervisor.

Another important change in Section 1 concerns the collection of baseline data and environmental monitoring programs. Previously, collection of baseline data pertaining to water, air, flora and fauna was required for two full, consecutive years, one full year of which was required before submission of a detailed development plan. Environmental monitoring was to be conducted before, during and subsequent to development operations; however, monitoring could be suspended after two years of baseline data collection and need not be resumed until six months before actual development operations begin.

As we interpret the final lease, collection of baseline data will be required for one full year before submission of a development plan and monitoring will be conducted continuously for as long as the Mining Supervisor deems necessary to establish environmental conditions after termination of development operations. As changed, however, the language is confusing; there could even be an error. If so, our interpretation may not be correct.

Other changes in the stipulations are minor in nature. Pipeline construction standards have been simplified by merely referencing 49 CFR parts 190, 192 and 195. In the description of a management plan, Section 11, the lessee is now required to base erosion control plans and procedures on a maximum 100-year precipitation rate, if such data are available, rather than on a 50-year precipitation rate.

In other sections of the stipulations, the BLM District Manager is given authority for approval of some plans, rather than the Mining Supervisor.

<u>Environmental Advisory Panel</u>

The final environmental statement issued on August 30 indicated that an Oil Shale Technical Advisory Board would be created if the decision to proceed with the program were made. A proposed Secretarial Order to that effect was included in Volume IV, pp. 1-15 thru 1-17 of the statement. The function of the Board would be to advise the USGS Mining Supervisor and BLM District Manager in carrying out their respective duties under the leasing program. As proposed, the Board would have no

TABLE 3

LOCATIONS & GEOLOGIC HORIZONS
TOSCO COREHOLES ON TRACT C-a

Hole Number	Location	Formation	Depth	Elevation	Total Depth
C-a-1	2062.0' S.N.L. 72.5' W.E.L. Section 4, T2S R99W	Surface Base "A" Groove Mahogany Marker Top "B" Groove Top Garden Gulch Mbr.	0' 266' 291' 384' 1073'	+6741' +6475' +6450' +6357' +5668'	1073'
C-a-2	4182.0' N.S.L. 1760 0' W.E.L. Section 32, T1S R99W	Surface Base "A" Groove Mahogany Marker Top "B" Groove Top Garden Gulch Mbr.	0' 216' 240' 333' 1022'	+6993' +6777' +6753' +6660' +5971'	1022'
C-a-3	1626.0' S.N.L. 815.0' W.E.L. Section 34, T1S R99W	Surface Base "A" Groove Mahogany Marker Top "B" Groove Top Garden Gulch Mbr.	0' 577' 602' 695' 1384'	+6652' +6075' +6050' +5957' +5268'	1384'

TABLE 4

COREHOLE DRILLING IN CONJUNCTION
WITH LEASING PROGRAM

TRACT	OPERATOR	NO. OF HOLES	PARTICIPANTS
C-a	Cameron Engineers, Inc.	5	Ashland, Carter, Fina, Gulf, Marathon, Mobil, Phelps-Dodge, Sun
C-a	Cameron Engineers, Inc.	4	Ashland, Fina, Marathon, Phelps-Dodge, Shell, Sun
C-a	Amoco Production	3	Unknown
C-a	TOSCO	3	Unknown
C-b	TOSCO	5	ARCO, CITGO, Geokinetics, Gulf, Mobil, Shell, Sun
C-b	TOSCO	4	ARCO, Gulf
U-a	Gulf	4	None
U-b	Gulf	3	Mobil, Sohio
	Shell	1	Bell, Gulf, Mobil, Sun, Superior, TOSCO
Near C-a	Garrett (Occidental)	1	Amoco, Carter, Mobil
	Barodynamics	1	None

express authority to accept or reject detailed development or other plans required by the lease form but must be afforded the opportunity to view the plans and comment thereon before approval by the Mining Supervisor or District Manager. The Board would be comprised of Federal officials; State and local representatives would be invited as observers.

In his November 28th announcement, Secretary Morton announced the intention to create an Oil Shale Environmental Advisory Panel to be composed of representatives from Interior and other Federal agencies, State and local governments, and the private sector. The function of the Environmental Panel will be to assist the Mining Supervisor in the conduct of public hearings on the environmental aspects of the detailed development plan required by the lease form. According to sources in Interior, the Environmental Panel replaces the Technical Advisory Board. State and local representatives on the Environmental Panel will be full members rather than "observers." A Secretarial Order is necessary to create the Panel.

Withdrawal Order Modification

A necessary formality to permit the sale of oil shale leases is modification of Executive Order No. 5327 of April 15, 1930, which withdrew oil shale deposits in Colorado, Wyoming, and Utah from leasing. Public Land Order 5401, which is published in the November 30 Federal Register, accomplishes this by modifying the Executive Order to permit the leasing of those lands contained in the six tracts to be offered for lease.

In addition to the lease tracts proper, the Department of the Interior is withdrawing from all forms of appropriation under the public land laws, including the mining laws, certain lands in the vicinity of lease tracts. In some situations, such lands may be required under statutes other than the Mineral Leasing Act for roads, spent shale disposal or other purposes in connection with the leasing program. According to the Federal Register notice, the Interior Department themselves may wish to conduct investigations, studies or experiments, particularly in connection with spent shale disposal. A public land order withdrawing these additional lands has not yet been issued but will likely appear within the next month. The area in question is not further defined in the notice.

TOSCO Coreholes Completed

As mentioned in the September 1973 issue of Synthetic Fuels, page 21, The Oil Shale Corporation drilled three additional coreholes on Tract C-a during the past three months. The locations and geologic prognoses of the holes are summarized in Table 3.

Drilling Summary Provided

A listing of those companies who have either drilled or participated in the drilling of coreholes during the leasing program is given in Table 4.

# # # #

III
oil sands

ALBERTA ISSUES THREE NEW OIL SANDS PERMITS

Three new oil sands exploration permits have been issued by the Province of Alberta, two in the Peace River Area and one in the Cold Lake Area. The permittees and acreage involved are shown in Table 1.

Shell's permit 14 occupies much of T84N-R18W and T84N-R19W with smaller portions in adjoining townships in the Peace River Area. Mobil's permit 15, also in the Peace River Area, occupies parts of T84N-R14W, T84N-R15W, T84N-R16W and T83N-R15W. Permit 16 is in the Cold Lake Area T63N-R4W and T63N-R5W.

There were no changes in the status of any of the Bituminous Sands or Oil Sands leases. The last complete listing, and location maps for all leases and permits was presented in the September 1973 issue of Synthetic Fuels, page 3-1.

TABLE 1

Permit No.	Acreage	Permittee
14	40,081	Shell Canada Ltd. and Shell Explorer, Ltd.
15	20,224	Mobil Oil Canada, Ltd.
16	17,132	Bailey Selburn Oil & Gas, Ltd. and Pacific Petroleum Ltd.

# # # #

FREEZE-THAW METHOD FOR CLARIFYING POND WATER PATENTED

U.S. Patent 3,751,358, assigned to Great Canadian Oil Sands Limited, describes a freeze-thaw method of water treatment by which agglomerated clay solids are compacted and may be removed from waste "pond water," leaving clarified water suitable for recycle to the hot water tar sands process.

According to the patent, waste effluent water discharged from the hot water tar sands separatory process contains agglomerated silt and clay solids which can be frozen, then thawed and that this freeze-thaw treatment compacts the agglomerated clay solids. After the freeze-thaw treatment, the compacted agglomerates settle to 30 percent solids, compared with about 10 percent solids composition in settling of solids without freezing and thawing.

It is believed that the freezing causes solids compaction by concentration, then compression of clay solids in the agglomerates. Upon thawing, the dense agglomerates settle to the higher percent solids sludge than would occur without freezing.

The clarified water, substantially reduced in solids content, is suitable for recycling.

# # # #

CANADIAN PETROLEUM GEOLOGISTS HOST OIL SANDS SYMPOSIUM

"Oil Sands, Fuel of the Future" was the theme of a symposium hosted by the Canadian Society of Petroleum Geologists (CSPG) on September 5-9, 1973 in Calgary, Alberta. Nearly 600 attendees from Canada, the United States, South America, France, England, and Japan heard 20 papers at the two-day technical session; a two-day field trip followed the technical sessions. All in all the symposium was exceptionally well organized and must be viewed as the most comprehensive meeting dealing with the subject of oil sands in many years.

Papers presented described geology and methods of production varying from the active Great Canadian Oil Sands Ltd. operation to experimental in situ methods. Most of the papers were aimed at the Western Canada oil sands deposits. One paper described the heavy oil sands of the Orinco petroleum belt in Venezuela and another paper described the heavy-crude bearing sandstones in the mid-Pennsylvanian (Desmoinesian) Cherokee Group of Southeast Kansas.

Unfortunately, only a limited number of papers were available for detailed review which precludes a complete discussion at this time. Following are reviews of those presentations for which copies of papers were available or for which sufficient information has been made available to permit a meaningful review. For a complete list of authors and papers see the RECENT PUBLICATIONS section of this issue. The CSPG has announced plans to publish the complete proceedings of the Symposium in early 1974 at which time we will summarize those papers not reviewed following.

Crash Programs -- The Time is Here According to Mines Minister Dickie

Alberta Mines Minister William Dickie presented a speech to the assembly of nearly 600 geologists at the Thursday luncheon. His address, containing an eight-point developmental program, pressed for immediate large scale development of the Canadian oil sands. Action to be taken would include a $500 million, 5-year investment in research directed at in situ recovery methods. Although Mr. Dickie's statements have been overshadowed by more recent events, particularly the Federal-Provincial controversy over oil, it is substantially summarized following since it represents, at least, an official philosophy of Alberta on oil sands development.

In situ recovery methods, if developed, could permit the recovery of 90 percent of the 300 billion barrels of reserves at Athabasca, according to Dickie.

Dickie expressed his disappointment with the apparent lack of interest by the U.S. Government. He acknowledged the fact that Japanese and Russian missions have studied possible Canadian oil sands participation but could not recall a mission from the United States which showed that interest. Dickie also wants Alberta syncrude free of export controls.

The eight point developmental program proposed by Dickie is:

(1) That present day policies of petroleum companies and governments be reviewed as of January 1, 1974 and directed toward crash programs with as early development as possible;

(2) That at least $100 million per year be spent for the next five years in Alberta in pursuing the in situ process;

(3) That the provincial and federal governments make substantial contributions to research and development;

(4) That there be meetings with representatives of the provincial government, federal government and the United States government to discuss research and development of in situ methods;

(5) "We will continue to oppose the federal government suggestion that there is need for control on export of crude oil. In the event the government proceeds with permanent controls, then we would like to suggest that the federal government grant exemptions from export controls on any synthetic crude oil from any in situ mining method going into production before 1987..."

(6) That the Japanese be given the opportunity and the encouragement to participate in oil sands development;

(7) That the government proceed with a proposed mission to Venezuela and the Middle East to determine the interest of those countries in investing in the oil sands of Alberta; and

(8) That the Alberta government receive valuable assistance from a report it has commissioned on the evaluation of Athabasca synthetic crude oil products.

> This project consists of determining the real value of hydrocarbon products potentially available from the Athabasca oil sands...The purpose of the analysis will be to provide the basic raw data for consideration of various processing schemes and to make comparisons with conventional crude products.

Mr. Dickie ended his luncheon speech with an appeal for cooperation, "In conclusion, the one message I hope to have conveyed today is that the major resource is here, it requires government and industry working together NOW!"

<u>"The Cold Lake Oil Sands: Geology and a Reserve Estimate" presented by Minken of the ERCB</u>

Douglas F. Minken of the Alberta Energy Resources Conservation Board presented the geology and a reserve estimate of the Cold Lake deposit to the symposium. His paper has been published by the ERCB as Report 73-L-GEOL entitled "Geology and Proved In Place Reserves of the Cold Lake Oil Sands Deposits".

Corehole and logging data from 412 wells were used in preparation of the reserve estimate. A proved in-place total reserve of 164 billion barrels of crude bitumen exists in four stratigraphic units, the Upper Grand Rapids, Lower Grand Rapids, the Clearwater and the McMurray formations. A type log and structural cross-section of the deposits are well illustrated in the published report as are structural contours on the Mannville group and the paleozoic surface. Also presented was a crude bitumen saturation-resistivity-porosity relationship which is illustrated graphically in the report for porosities of 30, 35, 40 and 45%. Table 1, reproduced following from the published report, summarizes the reservoir factors and reserve figures for the deposits.

<u>"Cretaceous Oil Sands of Western Canada" Described by Jardine of Imperial</u>

Dan Jardine of Imperial Oil Ltd. in Calgary described the areal distribution of the oil sands of Western Canada as extending over a distance of nearly 500 miles. The oil sands are highly porous, poorly consolidated freshwater to brackish water sands. The oil gravity varies from 8° to 12° API. The oil is found trapped by unconformable contact at Peace River in the basal Cretaceous Bullhead sands. Oil is found in the Upper Manville sand in structural traps and in the basal Wabasca sand in stratigraphic traps in the Wabasca area. Cold Lake oil is found in all sands of the Upper Manville with porosity being the key to oil accumulation. The McMurray area oil sands are basal Cretaceous strata with the oil being trapped over a broad domal structure. Up dip closure on the domal structure is believed to be the result of north-south trending subsidence over salt solution features in lower Pre-Cretaceous strata.

Alberta's Oil Sands In The Energy Supply Picture Described by Govier

Dr. George W. Govier, Energy Resources Conservation Board of Alberta, presented a paper outlining the conventional crude oil production picture and the degree to which needed production of synthetic crude from the oil sands will be able to supplement crude supply in the future. As with Mr. Dickie's remarks, the text of Dr. Govier's presentation is reviewed in depth due to the source and significance of his comments.

Conventional crude production from Alberta's crude reserves has been increasing at a desperate rate in an attempt to satisfy growing demand. Total production including gas distillate and synthetic crude production increased from 1.16 million bbls/day in 1971 to 1.37 million bbls/day in 1972, a jump of 20.8 percent. Dr. Govier projects an average production increase for 1973 of nearly 22 percent. Coupled with the increasing production rate is an alarmingly low crude discovery rate which is resulting in a decline in the recoverable reserves. Figure 1 graphically displays the initial recoverable reserves in relationship to existing proven remaining reserves. An increase in initial recoverable reserves of 200-300 million bbls/year over the next decade may be projected; however, the anticipated production for the next few years is in excess of 500 million bbls/year indicating that Alberta's remaining recoverable reserves will continue to decline.

TABLE 1

SUMMARY OF RESERVOIR FACTORS AND PROVED IN PLACE RESERVES OF CRUDE BITUMEN
COLD LAKE DEPOSIT

DEPOSIT	SATURATION CATEGORIES (Weight %)		VOLUME (Acre-Feet) 10^6	AREA (Acres)	AVERAGE THICKNESS (Feet)	AVERAGE POROSITY (%)	AVERAGE CRUDE BITUMEN SATURATION (Weight %)	(Volume %)	PROVED IN PLACE RESERVES OF CRUDE BITUMEN (Billions of Barrels	
UPPER GRAND RAPIDS MEMBER	Lean	3-4.99	8.3	1,488,875	5.6	33.7	4.1	8.1	5.2	
	Intermediate	5-9.99	19.8	1,587,248	12.5	36.7	7.4	14.8	22.6	
	Rich	10 or greater	6.7	720,863	9.3	38.6	11.8	23.6	12.2	
									TOTAL	40.0
LOWER GRAND RAPIDS MEMBER	Lean	3-4.99	9.7	1,581,694	6.1	35.3	4.1	8.1	6.1	
	Intermediate	5-9.99	32.4	1,800,254	18.0	35.3	7.4	14.8	37.2	
	Rich	10 or greater	18.8	1,067,064	17.7	39.7	11.8	23.6	34.5	
									TOTAL	77.8
CLEARWATER FORMATION	Lean	3-4.99	5.5	648,503	8.5	34.0	4.3	8.5	3.6	
	Intermediate	5-9.99	12.2	588,206	20.7	36.5	7.6	15.2	14.4	
	Rich	10 or greater	8.3	412,734	20.1	39.5	11.4	22.8	14.7	
									TOTAL	32.7
McMURRAY FORMATION	Lean	3-4.99	1.8	499,726	3.6	38.1	4.1	8.2	1.1	
	Intermediate	5-9.99	7.6	704,873	10.7	41.9	7.5	15.0	8.8	
	Rich	10 or greater	2.0	275,608	7.2	46.0	11.5	23.0	3.6	
									TOTAL	13.5
									GRAND TOTAL	164.0

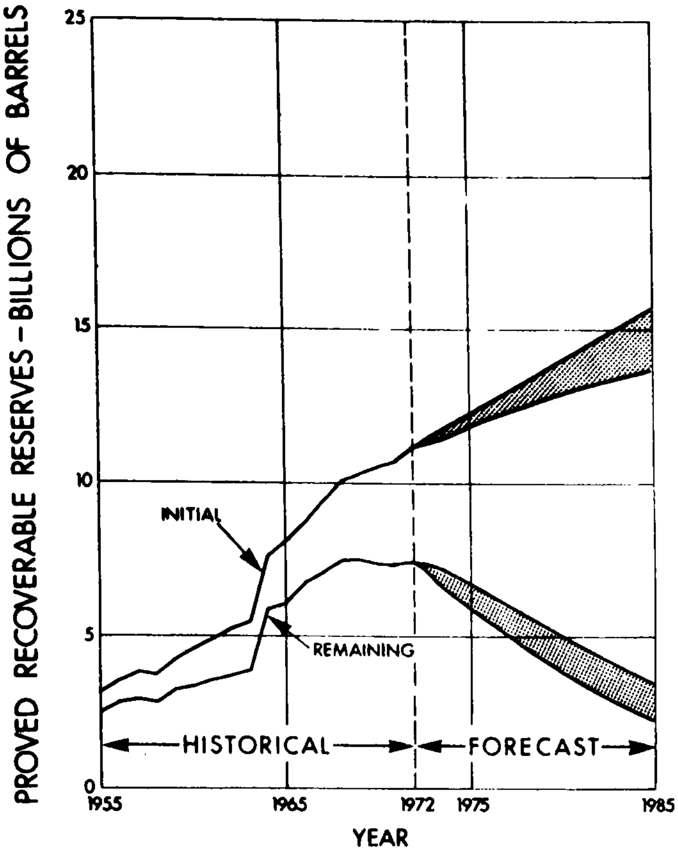


FIGURE 1 - RECOVERABLE RESERVES OF CONVENTIONAL CRUDE OIL IN ALBERTA

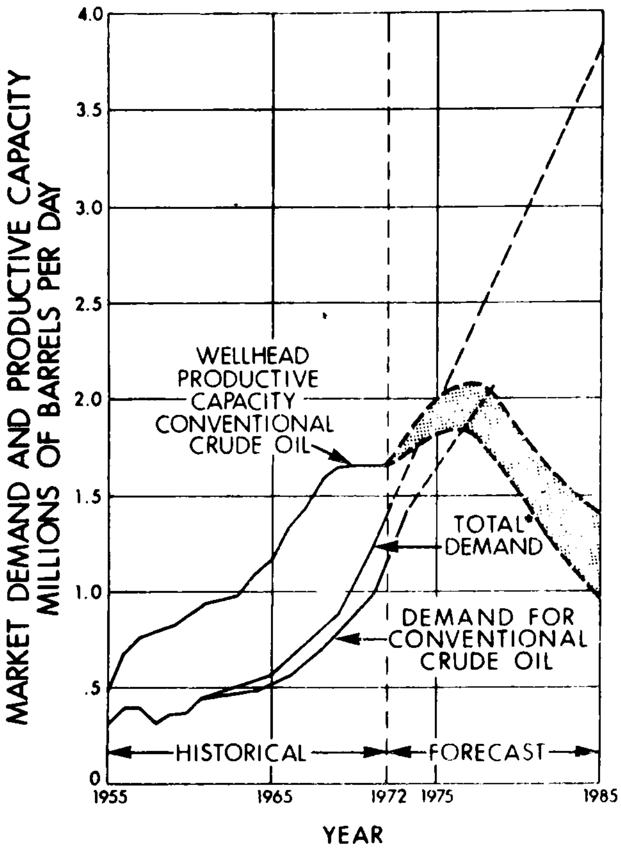


FIGURE 2 - MARKET DEMAND AND PRODUCTIVE CAPACITY FOR ALBERTA CRUDE OIL

*CONVENTIONAL AND SYNTHETIC CRUDE OIL AND EQUIVALENT

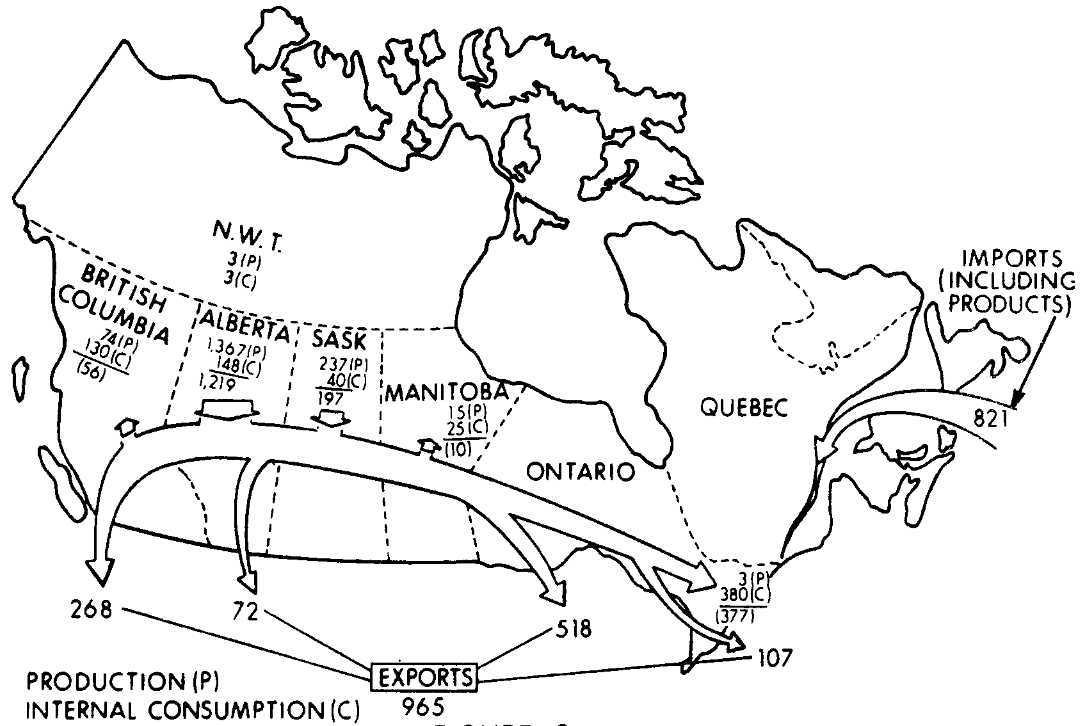


FIGURE 3

MOVEMENTS OF OIL* WITHIN, TO, AND FROM CANADA, 1972

(THOUSANDS OF BARRELS PER DAY)

* CONVENTIONAL AND SYNTHETIC CRUDE OIL AND EQUIVALENT

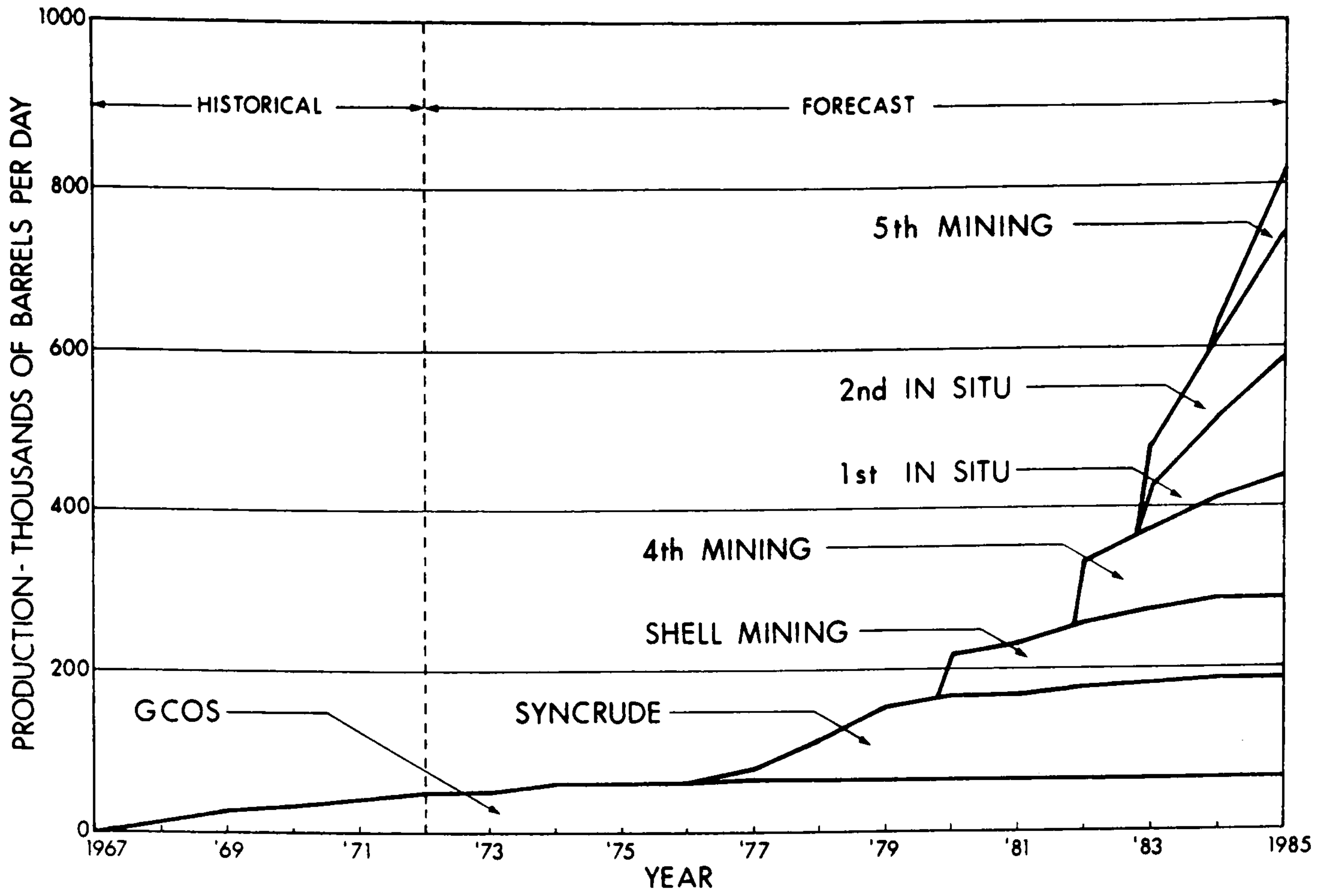


FIGURE 4 - ALBERTA SYNTHETIC CRUDE OIL PRODUCTION

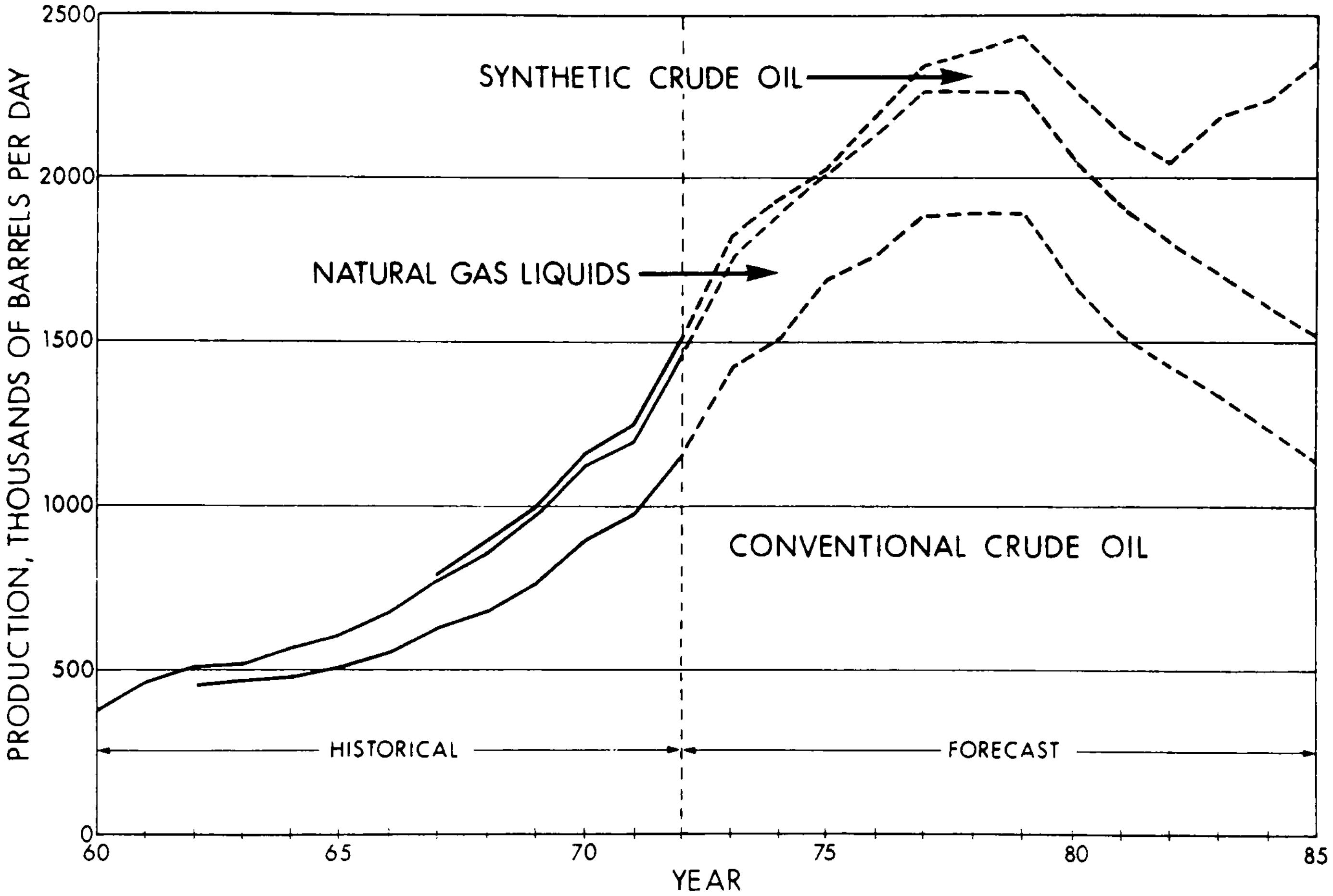


FIGURE 5 - ALBERTA LIQUID HYDROCARBONS PRODUCTION

Figure 2 shows the historical and projected total demand for Alberta oil. Demand for conventional crude has been lowered by the amount of gas distillate and synthetic oil produced. Gas distillate and synthetic crude amounted to an average per day production of 162,999 and 51,000 barrels respectively for 1972. Production capacity of conventional crude is leveling off indicating a need for much higher distillate and synthetic crude production in the future.

During 1972, export of Alberta crude to the growing market in the United States amounted to 965,000 bbls/day. Total imports of crude and equivalent into Canada averaged 821,000 bbls/day, with the result that Canada became a net exporter of crude oil and equivalents. Figure 3 shows the production supply and dispersion of crude oil and equivalents for Canada in 1972.

Alberta oil sands contain 27 billion barrels of synthetic crude recoverable by currently feasible means, such as the surface mining and hot water extraction process utilized by GCOS. Recovery by development of now experimental processes such as in situ recovery may lead to an ultimate recoverable reserve of 900 billion barrels. Dr. Govier says the presently recoverable reserve estimates are adequate to support 20 to 30 plants producing a total of three million bbls/day.

Dr. Govier places limits on future production by explaining the magnitude of the construction program necessary to ready an oil sands plant for production. An oil sands plant capable of 100,000 bbls/day production would take five or six years to build and would cost an estimated $800 million dollars. Also, available supply of large machines and equipment may limit the number of plants that may be constructed at any one time. These limits lead Dr. Govier to predict that the production of synthetic crude by 1980 will not exceed 200,000 bbls/day but that it could reach 800,000 bbls/day by 1985.

Great Canadian Oil Sands, Ltd. is now producing 51,000 bbls/day of synthetic crude with approval to produce 65,000 bbls/day. Syncrude Canada Ltd., with operations similar to GCOS, projects production beginning in 1977, increasing gradually to 104,000 bbls/day by 1980 and full production of synthetic crude of 125,000 bbls/day by 1984. Shell Canada Ltd. and Shell Explorer Ltd. are proposing the production of 100,000 bbls/day beginning in 1980 and attaining full production by 1982. Figure 4 shows Dr. Govier's projection of the growth of synthetic crude oil production. Figure 5 shows the effect projected synthetic crude oil production will have on total hydrocarbon production considering the projected decline of conventional crude oil.

Cameron Engineers believes it should be apparent from the present energy picture that development of alternate energy sources such as synthetic fuels must be hastened. A massive response by industry is required together with governmental cooperation in the expedient formation of operative regulations.

# # # #

GCOS SULFUR REMOVAL OPERATIONS DESCRIBED

W. S. Tostevin of GCOS presented a paper at the Fourth Joint Chemical Engineering Conference in Vancouver last September describing the procedures employed at the GCOS plant to remove sulfur from bitumen. In the paper, "Sulfur Removal From the Athabasca Bitumen," Tostevin notes that Athabasca bitumen, containing 4.5 to 5.0 wt. % sulfur, has twice the sulfur content of a representative western Canadian sour crude. Further, the synthetic crude product which contains 0.15 wt. % sulfur is sweeter than IPPL mixed sweet crude - the best that Canada offers. Per barrel sulfur removal load at GCOS is thus between five and ten times that of an average Canadian refinery. Considering the current weak sulfur market, sulfur removal costs represent a measurable portion of the final product cost.

Sulfur Removal in Two Operations; Emphasized in Hydrotreating

The overall sulfur balance in the GCOS operation is indicated in Table 1, where it may be seen that 60% of the sulfur entering is recovered as elemental sulfur through the treatment of acid gas in the two-stage Claus unit. The acid gas originates in the gas

TABLE 1

OVERALL SULFUR BALANCE
(Basis: 100 lbs of sulfur in bitumen feed)

SULFUR DISPOSITION:		Lbs.
TO STORAGE (Elemental sulfur)		60
TO COKE:	FUEL	23
	STOCKPILE	5
TO TAIL GAS		4
SOUR WATER		5.5
TO SYNTHETIC CRUDE		2.5
TOTAL		100 lbs.

recovery section of the delayed coker units and the Unifiners; the majority from the latter. Approximately 28% of the sulfur entering the plant leaves the cokers in the bitumen coke. The two operations in which sulfur is removed from the bitumen are the cokers and the catalytic hydrogenation units.

Tostevin observes that since the primary purpose of the delayed cokers is to maximize bitumen conversion, sulfur removal in that step is not optimized. As indicated, the major portion of the sulfur is contained in the acid gas from the cokers and the hydrotreaters. Overall removal efficiency of sulfur from coker distillates by the hydrogenation units is claimed to be 97%.

The operating variables for the three Unifiner hydrotreaters (naphtha, gas oil, and kerosene) are shown in Table 2. The catalyst preferred by GCOS is a nickel-molybdenum type on an alumina base which is noted as being superior to cobalt-moly catalyst can also tolerate a relatively high carbon content (up to 15%) before regeneration is necessary.

The hydrotreaters, of course, also serve to saturate olefins and aromatic compounds in their respective distillate feeds as well as to remove nitrogen. Table 3 indicates the extent of sulfur and nitrogen removal in the hydrotreaters. The decrease in volume of aromatics and the gravity improvement is also shown. For comparison, the level of these variables in the raw bitumen and final synthetic crude product is also listed.

Sulfur Not Viewed As Marketable By-Product

The outlook for marketing the sulfur by-product from an oil sands plant is bleak indeed from the GCOS experience. The 250 billion barrels of bitumen believed recoverable by surface mining and in situ techniques from the Athabasca oil sands represent 1.8 billion long tons of sulfur or a 60-year inventory of the free world consumption rate of 30 million LTPY. By the year 2000, when some believe that as many as 10 oil sands plants could be on stream, sulfur production from these plants

TABLE 2

HYDROTREATER OPERATING CONDITIONS

	NAPHTHA	KEROSENE	GAS OIL
REACTOR BED TEMPERATURE (°F)	500-750	550- 720	600-750
REACTOR PRESSURE (PSIG)	800	1400	1200
RATIO HYDROGEN FEED (SCF/Bbl.)	500-800	750-1100	650-850
SPACE VELOCITY (LHSV)	2	1	1
REACTOR FEED PHASE	Vapor	Trickle	Trickle

TABLE 3

TYPICAL ANALYSIS

STREAM	SULFUR (WT %)	GRAVITY (°API)	AROMATICS (Vol.%)	TOTAL NITROGEN (PPM)
BITUMEN:	4.5 to 5.0	10	45	3000 to 6000
NAPHTHA:				
Distillate	1	55	18	80
Product	25 (PPM)	62	No Spec.	<1
KEROSENE:				
Distillate	1.8	32	37	320
Product	10 (PPM)	39	17	<1
GAS OIL:				
Distillate	2.9	19	65	1440
Product	2500 (PPM)	23	43	300
SYNTHETIC CRUDE:	0.15	36	27	175
Naphtha 23%				
Kerosene 23%				
Gas Oil 54%				
100%				

could be as high as 10 million LTPY, 1/3 of the current free world demand and 50% greater than current sulfur production in Alberta.

Sulfur recovered in the increased production of natural gas in the Province has resulted in substantial stockpiles to the extent that the Alberta inventory is expected to increase 3 million LT in 1973 to 12 million LT. Even at recent price highs approaching $12 per LT, the sulfur by-products from the GCOS plant can't hope to compete. Transportation costs from Ft. McMurray to Edmonton are $10 per LT minimum and another $3 per ton would be required to remelt and load present stockpiles. It may thus be anticipated that, like GCOS, the proposed Syncrude and Shell plants will stockpile the sulfur with little hope for marketing it. Neither Shell nor Syncrude have assumed a by-product sulfur credit in their economic projections.

# # # #

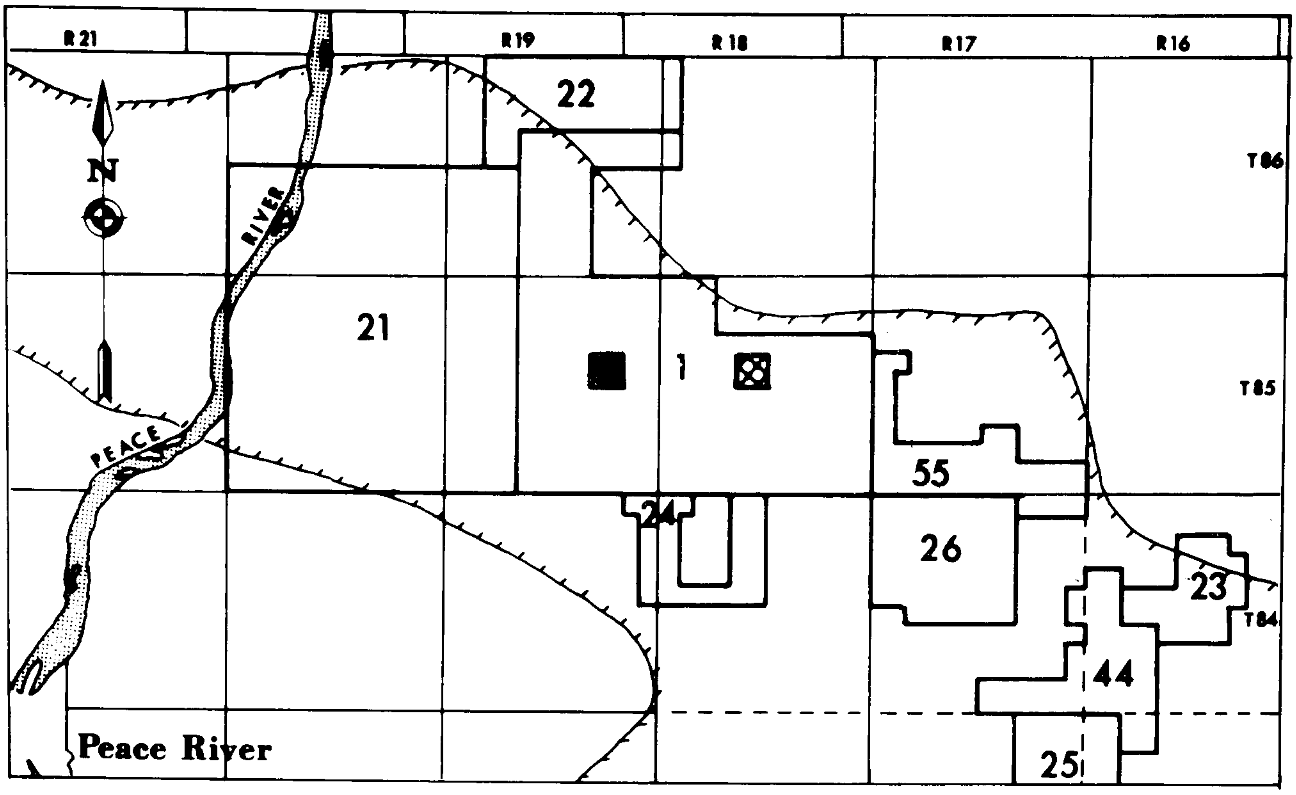


FIGURE 1

LOCATION OF IN SITU EXPERIMENTAL PROJECTS
OF
SHELL CANADA, LTD.

Legend:

LOCATION OF EXPERIMENTAL PROJECTS (APPROVAL NOS. 534 & 739) NOW TERMINATED.

LOCATION OF NEW EXPERIMENTAL PROJECT

BOUNDARY OF AREA OF PEACE RIVER DEPOSIT EVALUATED BY ERCB

21 OIL SANDS LEASE BOUNDARY AND LEASE NUMBER HELD BY SHELL

SHELL ACQUIRES EXPERIMENTAL PROJECT APPROVAL IN PEACE RIVER AREA - IMPERIAL TESTS CONTINUE IN COLD LAKE

Shell Canada, Ltd. has acquired an experimental permit (Approval No. 1904) from the Energy Resources Conservation Board (ERCB) for renewing their in situ experimental work in the Peace River oil sands deposit of Alberta. A previous article on Shell's in situ project appeared in Synthetic Fuels June 1973, p. 3-11. Shell was active under two prior experimental permits during the period 1952 through 1967. These permits, subsequently terminated, were located on Shell's Oil Sands Lease No. 1 as is the current project area; the new work, however, will be undertaken approximately four miles east of the previous experiments. Details of applications for experimental permit and operations conducted thereunder are held confidential by the ERCB. The locations of Shell's earlier and planned in situ projects are shown on Figure 1.

Other companies having active oil sands experimental projects in Alberta are Imperial Oil Limited (four approvals in Cold Lake), Amoco Canada Petroleum, Ltd., and Texaco Exploration Canada, the latter two companies operating under one permit each in the Athabasca deposit. The location and identification of all active and terminated oil sands experimental projects were described in the September 1972 issue of Synthetic Fuels, p. 3-27.

Imperial Oil steam stimulation operations in Cold Lake are now aimed at a production of 4000 BPD from the heavy oil deposits as a result of a recent application to the ERCB (see the September, 1973 issue of Synthetic Fuels, p. 3-22). Imperial had invested some $15 million by the end of 1971 on these tests which reportedly employ "huff and puff" techniques followed by a steam drive. Last year Imperial offered for sale the technical data accumulated to that point along with the right to monitor the ongoing program. Five companies out of about 20 contacted have purchased Imperial's data under this arrangement. To date, however, Imperial is not prepared to suggest when in situ recovery will be commercially viable, indicating only that the tests could well proceed for five years or more.

# # # #

SHELL APPLIES FOR ALBERTA TAR SANDS STRIP MINING OPERATION

Shell Canada Limited and Shell Explorer Limited have applied to the Energy Resources Conservation Board (ERCB) of Alberta for approval of a mining and processing scheme for their 49,872-acre Bituminous Sands lease No. 13 some 38 miles north of Fort McMurray. Although Shell had announced the submission of their application earlier this year, the application was not formally accepted by the Board until the last week in August. The estimated capital cost of Shell's project through the year 1980 is $710 million, including a $30 million expenditure for pre-development mining.

In 1962 Shell applied to the Province for permission to build a 95,000-bpd plant on this lease but was turned down in favor of the application of GCOS who had filed earlier. Shell was at that time given a preferential position for subsequent consideration if they submitted an application no later than December 31, 1968. Shell announced late that year their intent to defer submitting an application in favor of pursuing conventional oil prospects (see the December 1968 issue of Synthetic Fuels, p. 80).

The current application is for 100,000 barrels per day of synthetic crude oil with initial production scheduled for early 1980 and full scale production early in 1982. Construction would start on major facilities in January 1976. The application is reproduced in full in the appendix beginning on page A-1 and is reviewed in the following paragraphs followed by a brief comment on the hearings held by the ERCB thereon. A combined extraction and upgrading flow sheet reconstructed from the application is presented as Figure 1 on page 3-12.

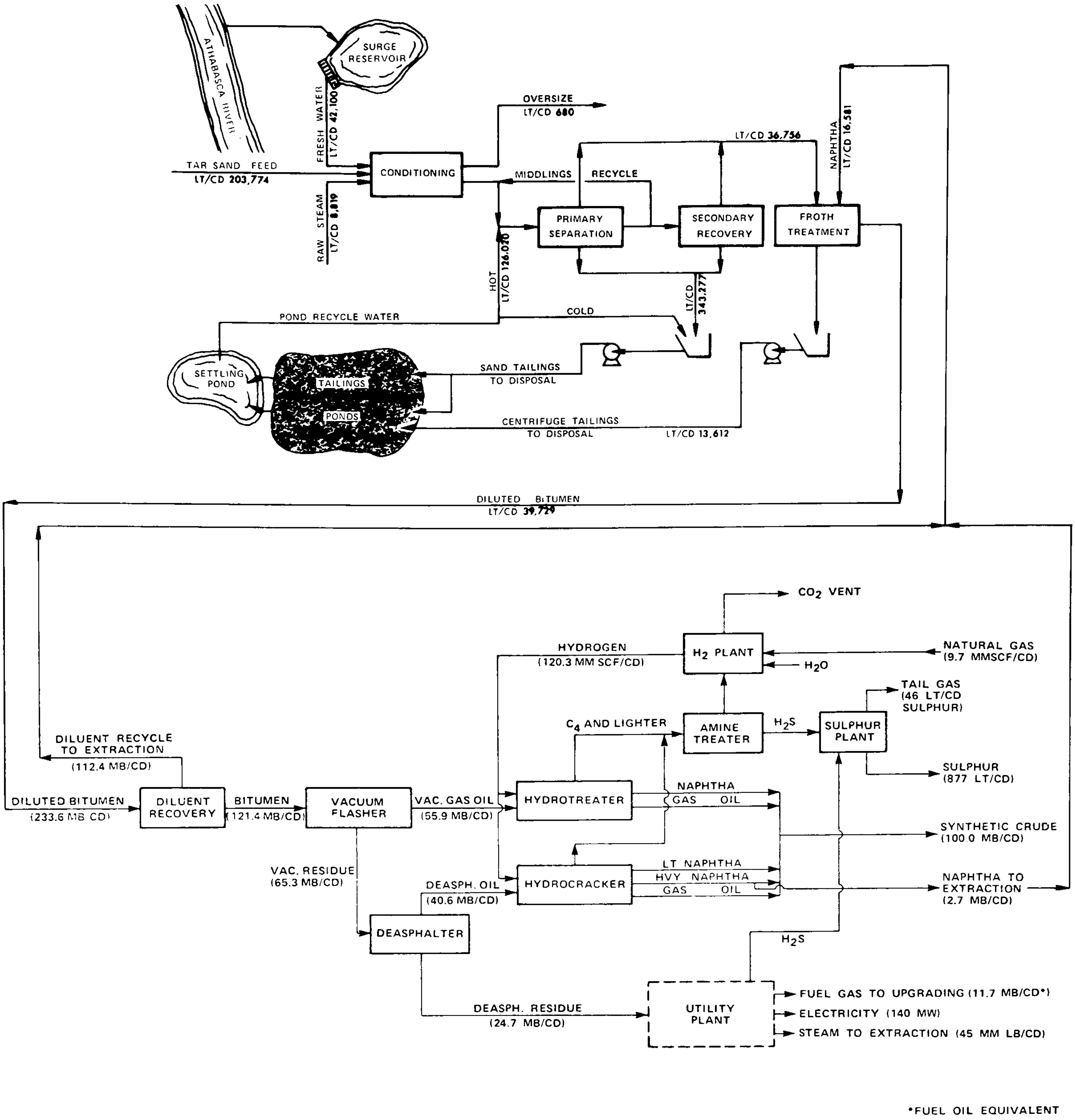


Figure 1

SCHEMATIC FLOW DIAGRAM

100,000 BPCD OIL SANDS PLANT

SHELL CANADA, LTD.

Geology, Reserves and Tar Sands Characteristics Described

Shell will have drilled a total of 297 holes on lease 13 by the end of 1973; this is equivalent to four holes per square mile. As with all of the Athabasca tar sands the primary host rock is the lower Cretaceous McMurray formation which ranges between 150 and 350 feet thick on the lease. A correlation technique was developed by Shell to determine bitumen content and clay characteristics from Laterolog, Formation Density Log and Gamma Ray Logs, thus reducing the amount of coring necessary. These correlations are well illustrated in their application.

Shell selected four ore bodies within the lease which they estimate to contain 3.72 billion barrels of bitumen in place of which 88% or 3.28 billion barrels is recoverable. The lease has been divided into polygons on drill holes and a "quality factor" developed for each polygon. From this evaluation, the four ore body area outlines were developed and ranked as to sequence in which mining is to commence, taking into account the grade and thickness of overburden and waste interburden. Detailed data on drill holes, polygons, quality factors, and reserve calculations are given in the application.

The fines content of the mill feed from this property is somewhat lower than from other leases which is advantageous in the hot water extraction process. The average grade of mill feed is 11.5 weight percent bitumen. Sand grains of the McMurray formation are water wet with the bitumen isolated from the grain by a water film. This is vital to the separation of the bitumen from the solids in the hot water process.

Mining To Be By Dragline

Four large walking draglines will be employed, each with a 75- to 90-cubic yard bucket and boom lengths sufficient to allow digging to a depth of from 200 to 240 feet. These machines will be used both to cast overburden into the mined-out portion of the strip and to stack mill feed onto a reclaim pile on the highwall. Availability of the draglines is assumed to be 70 to 75%.

The mill feed pile at each dragline will be reclaimed onto a belt conveyor system taking it to the car loader. Front end loaders will assist in reclamation. The feed will be loaded into trains of fourteen 100-ton side dump cars which will transport it to the treatment plant.

Recoverable reserves of the four areas outlined are sufficient to sustain a 100,000-bpd operation for 80 to 90 years.

Extraction To Be "Conventional"

Shell plans to utilize what must now be regarded as conventional extraction operations similar to the GCOS and the proposed Syncrude extraction trains. Bitumen will be extracted by the K. A. Clark hot water process in which hot water, caustic and steam are used to liquefy the bitumen to the point where gravity separation can be effected. The feed is to be heated to 180°F in each of two conditioning drums. The liquid feed goes to the primary separation cell where the bitumen froth is skimmed and a sand underflow is raked out. Secondary recovery from a middling stream is effected. The bitumen froth is heated and agitated to effect de-aeration, then centrifuged with recycle naphtha. The lighter and less viscous bitumen is thus more easily separated from the solids and water entrained in it. The process is anticipated to recover 90% of the bitumen feed.

Vacuum Distillation First Step in Upgrading

Upgrading of the bitumen to a synthetic crude oil uses commercially proven technology. Primary separation of the light fraction is by vacuum flashing with the vacuum residue subjected to solvent deasphalting. Deasphalting residue constitutes fuel to the utility plant. The utility plant is not fully detailed in the application but will be the subject of a future application under Section 7 of Alberta's Hydro and Electric Energy Act.

The vacuum gas oil will be hydrotreated and the deasphalter oil will be sent to a hydrocracker. The naphtha and gas oil streams from the hydrogenation units will then be combined to produce a synthetic crude with the following properties:

Gravity	30° API
Sulfur	0.4 w.t % max.
Nitrogen	0.1 wt. % max.
Volume Off at 390°F	10%
Volume Off at 1000°F	96%

As with the other oil sand projects, acid gas from the hydrogenation units will be followed by sulfur recovery in a Claus plant; Shell will employ two 3-stage Claus facilities.

Overall Recovery Factors Up Slightly

The Shell application infers increased recovery efficiencies in nearly every category over current GCOS operations and the proposed Syncrude plant. Table 1 is a comparison of the material balances (based on one ton of oil sands feed) for the Shell plant and the latest Syncrude plant configuration. Figures on recovery efficiencies being experienced in the GCOS operation are reviewed elsewhere in this issue of Synthetic Fuels in the description of the Board approval of the latest Syncrude applications.

Shell figures indicate production of 150.5 pounds of 30° API gravity synthetic crude from one ton of tar sands averaging 11.5% bitumen while Syncrude indicates production of 149.9 pounds of the same gravity product from one ton of 11.59% bitumen oil sands feed. Bitumen loss in the Shell plant is claimed to be 8.4% as compared to 8.9% in the Syncrude unit primarily due to the fact that Shell is recycling water containing a bitumen load to their extraction system. It must, of course, be recognized that the figures compared are no more than engineering estimates, albeit of the highest order; thus, there is little probability that the confidence factor, as high as it may be, in the figures set forth would permit a conclusion that the Shell operation will be more efficient than the Syncrude plant. Prudence would suggest that in submitting an application for a plant to go on stream some four years after Syncrude, the recovery efficiencies should not purposely be made less than the Syncrude figures.

Economics Now Outdated

Profitability is analyzed in the application both in terms of 1973 dollars and "Escalated Dollars." Earning power before income taxes is shown as 7% for the first case and 13% for the second. Royalty to Alberta is assumed as 16-2/3% of the price of the raw bitumen which is taken as 28% of the posted price for 38° API crude at Edmonton. This produces a considerably lower royalty, approximately one-half, than that projected for the Syncrude Project and may not be realistic. The assumed product price of $3.50 per barrel may have been reasonable last spring when the projection was made but is clearly outdated now.

Hearings Held on Application

Hearings on the application were held by the ERCB in Calgary on October 9. Shell witnesses detailed many of the areas covered above to the Board. Intervenors were GCOS, Ltd., Syncrude Canada, Ltd., Alberta Gas Trunk Line, Ltd., Petrofina Canada, Supertest Investments and Petroleum, Ltd., and Mr. W. R. Johns. The Committee for an Independent Canada, as a late intervenor, was given the privilege of cross examining witnesses.

Shell witnesses stated that public data and runs of Shell ore by GCOS under special arrangement form the basis for the material balance given in the application. Shell suggests that improvements in centrifuge design will yield a cleaner cut in this stage. Fines in the feed may not exceed 25%. Shell stated that they consider the vacuum distillation of bitumen to be similar to their present practice with heavy conventional crudes. They expect a 47% volume conversion in this step.

Testimony indicated that the deasphalter will employ light paraffinic hydrocarbons having a boiling range between propane and hexane. The hydrotreater will require 40 million standard cubic feet of hydrogen per day and the hydrocracker 80 million.

Shell, in response to questions from the Alberta Energy Resources Conservation Board,

TABLE 1

SUMMARY COMPARISON
PLANT MATERIAL BALANCES
(Basis: 2000 lbs. raw oil sands feed)

IN	SYNCRUDE[1]		SHELL	
Oil sands feed				
Bitumen	231.81 lbs	(11.59%)	230.00 lbs	(11.5%)
Water	88.19	(4.41%)	59.49	(3.0%)
Solids	1680.00	(84.0%)	1710.51	(85.5%)
Steam/Water (To Extraction)	1608.66		1736.62[2]	
H_2 Production				
Steam/Water	18.28		13.53	
Natural Gas	6.11		2.01	
H_2S (Exhaust from Utility Plant)	--		4.17	
Total In	3633.05 lbs.		3756.33 lbs.	
OUT				
Tailings/Reject				
Bitumen	20.53 lbs	(8.9% loss)	21.78 lbs.	(8.4% loss)
Water	1671.69		1752.81	
Solids	1678.36		1731.18	
Naphtha	2.60		3.69	
Sour Water (Naphtha recovery)	25.16		18.57[3]	
Coke[4]	35.16		--	
Sulfur (elemental)	7.23		9.64	
Fuel Gas	16.69		--	
Butane (C_4)	3.89		--	
Stack Loss (S, CO_2, and Steam)	21.87		17.59	
Vacuum Residue[4]	--		50.53	
Synthetic Crude		(0.489 Bbls.)	150.54	(0.491 Bbls.)
Naphtha	33.54	(0.128 Bbls.)		
Gas Oil	116.33	(0.361 Bbls.)		
Total Out	3633.05 lbs.		3756.33 lbs.	

(1) Figures based on material balance around initial production rate of 104,550 BPCD.
(2) Includes 22.26 lbs. solids and 2.47 lbs. bitumen in recycle pond water.
(3) Calculated (H_2O balance difference).
(4) Figures include solids carried over in bitumen from extraction.

gave total in-place bitumen reserves for Lease 13 as 10.2 billion barrels which includes areas both within and without the four ore bodies mentioned. A fifth ore body containing 1.3 billion barrels in place and too far toward the eastern limit of the lease to be within the economic reach of the presently contemplated plant is also included in this total. Diversion of the Muskeg River will be necessary at some point in mining. Of 150 holes to be drilled in 1973, 143 will be cored.

Testimony revealed that the two aquifers, the interorebody aquifer and the basal aquifer, have widely differing salinities and volumes. The interorebody aquifer runs 50 parts per million chlorine whereas the basal aquifer runs 1000 ppm chlorine but with only about a tenth the volume of the interorebody aquifer.

A Shell witness indicated that the mining plan provides four to eight hours of surge capacity ahead of the extraction plant. The preference presently is for use of large draglines for stripping. A 12-cubic yard Marion dragline is to be delivered next year. While this machine is considerably smaller than the 75- to 90-cubic yard units contemplated ultimately, it will be used to verify performance of draglines on lease 13. At full production this small machine would be able to strip 20 acres a year of an average 100-foot overburden. The 75- to 90-cubic yard machines are able to strip 130 to 160 acres a year at the same thickness. Shell witnesses testified that mine configuration will be determined in mid-1975 after completion of considerably more drilling.

Shell is considering the gasification of 24,700 barrels per day of deasphalter residue; the product gas would be used in the utility plant. The largest single units performing this function currently are operating at 15,000 barrels per day in Europe.

The ammonia content of the acid gas product is considered unfavorable by the ERCB in that it precludes the 97% sulfur recovery normally required for large gas plants. Each Claus unit will be designed to handle 60% of the acid gas produced, giving a total capacity of 120%.

Petrofina expressed some concern over reserves they hold adjacent to Shell's lease 13. Shell confirmed that their contemplated operations would not affect the Fina lease.

Under questioning by a representative of Alberta's Department of the Environment, Shell expressed confidence that environmental standards can be met. The Department representative pointed out that an environmental impact assessment report must be presented to the Minister.

In response to a question from the Committee for an Independent Canada it was stated that 2,000 to 3,000 jobs would be created during construction. A stable work force of nearly 1000 people would be necessary for operation of the project.

W. R. Johns, a Calgary mining engineer, was critical of Shell's mining approach and suggested as an alternative an underground method somewhat similar to blockcaving. The method was not described in full enough detail to pass on. The principal advantage claimed by Johns was more complete recovery of the resource.

Shell stated that no firm market commitments have yet been made for their contemplated production. Their economic projections do not include sulfur sales.

Comments

We are convinced that the ERCB will recommend approval of the Shell application subject to more detailed development plans being submitted to the Board. Whether Shell will wish to pursue their application to reality under the present oil export policy of the Dominion government and similar royalty terms offered to Syncrude may well be another matter.

# # # #

USERS OF GCOS SYNTHETIC CRUDE LISTED - 1973 FINANCIAL FIGURES REPORTED

The actual nominations of companies and refineries acquiring synthetic crude from the GCOS plant during the four-month period of August through November as well as their estimated requirements for the months of December and January are listed in Table 1. All information is taken from the monthly listing of nominations for Alberta oil published by the Provincial Energy Resources Conservation Board. A steam production problem at the GCOS plant in October reduced production to under 22,000 BPD for a one-week period.

GCOS recently released financial and production statistics for the 9-month period ending September 30, 1973. A modest third-quarter profit of approximately $200,000 is indicated to reduce the loss for the period to $2.3 MM. Production of nearly 53,000 BPCD was achieved during the third quarter to bring average production for the year-to-date to just under 48,000 BPCD. A summary comparison of the production and financial statistics is presented in Table 2.

# # # #

TABLE 1

TABULATION OF NOMINATIONS
FOR
SYNTHETIC CRUDE OIL
PRODUCED FROM ATHABASCA BITUMINOUS SANDS

Purchaser/Destination	Nominations, B/D August	September	October	November	Estimated Requirements, B/D December	January
Imperial Oil Limited/ Strathcona Refinery, Edmonton, Alberta	5,000	5,000	4,500	5,000	5,000	5,000
Winnipeg, Manitoba	-----	1,000	-----	-----	-----	-----
Murphy Oil Corporation/ Superior, Wisconsin	3,000	2,000	2,000	2,000	2,000	2,000
Ashland Oil Company/ St. Paul Park, Minnesota	8,000	8,000	8,000	8,000	8,000	8,000
Shell Canada, Ltd. Corunna, Ontario	9,700	10,000	4,500	3,800	6,700	9,300
Oakville, Ontario	-----	-----	2,900	3,000	-----	-----
St. Boniface, Manitoba	7,300	6,000	7,300	9,000	8,700	7,300
Sun Oil Company, Ltd. Sarnia, Ontario	10,000	10,000	10,000	10,000	10,000	10,000
Toledo, Ohio	12,000	12,000	12,000	12,000	12,000	12,000
TOTAL	55,000	54,000	51,200	52,800	52,400	53,600

TABLE 2

GCOS PRODUCTION & FINANCIAL DATA
CALENDAR YEAR 1973

	First Quarter	Second Quarter	Third Quarter	Total or Nine-Month Average
Production				
BPCD	54,289	36,758	52,924	47,985
MM Bbls.	4.89	3.34	4.78	13.0
Revenue				
$/Bbl.	3.56	3.78	4.16	3.84
$MM	17.3	12.6	20.3	50.2
Costs				
$/BBl.	3.34	4.85	4.12	4.02
$MM	16.2	16.2	20.1	52.5
Profit (Loss)				
$/Bbl.	0.22	(1.08)	0.04	(0.18)
$MM	1.1	(3.6)	0.2	(2.3)

ERCB RECOMMENDS APPROVAL OF SYNCRUDE APPLICATIONS FOR TECHNICAL CHANGES, START-UP DELAY AND POWER PLANT

The Energy Resources Conservation Board (ERCB) of Alberta has forwarded its report to the provincial government on the applications of Syncrude Canada, Ltd. to modify its proposed oil sands plant, to delay start-up of that facility to mid-1977, and for the construction of an on-site power plant. The report (ERCB No. 73-K-HE-OG) was issued on September 10 and recommends approval of the applications in all respects. Details of the applications and the hearings conducted by the ERCB thereon were reviewed in the June 1973 issue of Synthetic Fuels, p. 3-1.

The Findings and Decision of the ERCB and the Forms of Approval, as contained in the Board report, are reproduced in the Appendix of this issue beginning on page A-58. The significant elements of the Board's report relating to the applications are reviewed following.

Board's Concerns on Technical Changes Noted

The primary concerns expressed by the Board centered on the reduced recovery efficiencies, sulfur recovery and the fact that Syncrude intends to stockpile coke in lieu of using it as a fuel source. The flow diagram of the Syncrude plant as now envisioned is illustrated in Figure 1.

The recovery efficiency in the upgrading section of the plant (now being fluid coking instead of Hydrovisbreaking) decreased by the greatest amount. The upgrading recovery efficiencies of the several upgrading processes are shown in Table 1 which also indicates the actual efficiency being experienced by GCOS. Overall efficiencies of the Syncrude facility as now proposed, are compared to the prior Syncrude application as well as actual GCOS experience in Table 2.

The thermal (energy) efficiency of the Syncrude plant was noted by the Board to be estimated as eight percent higher than that

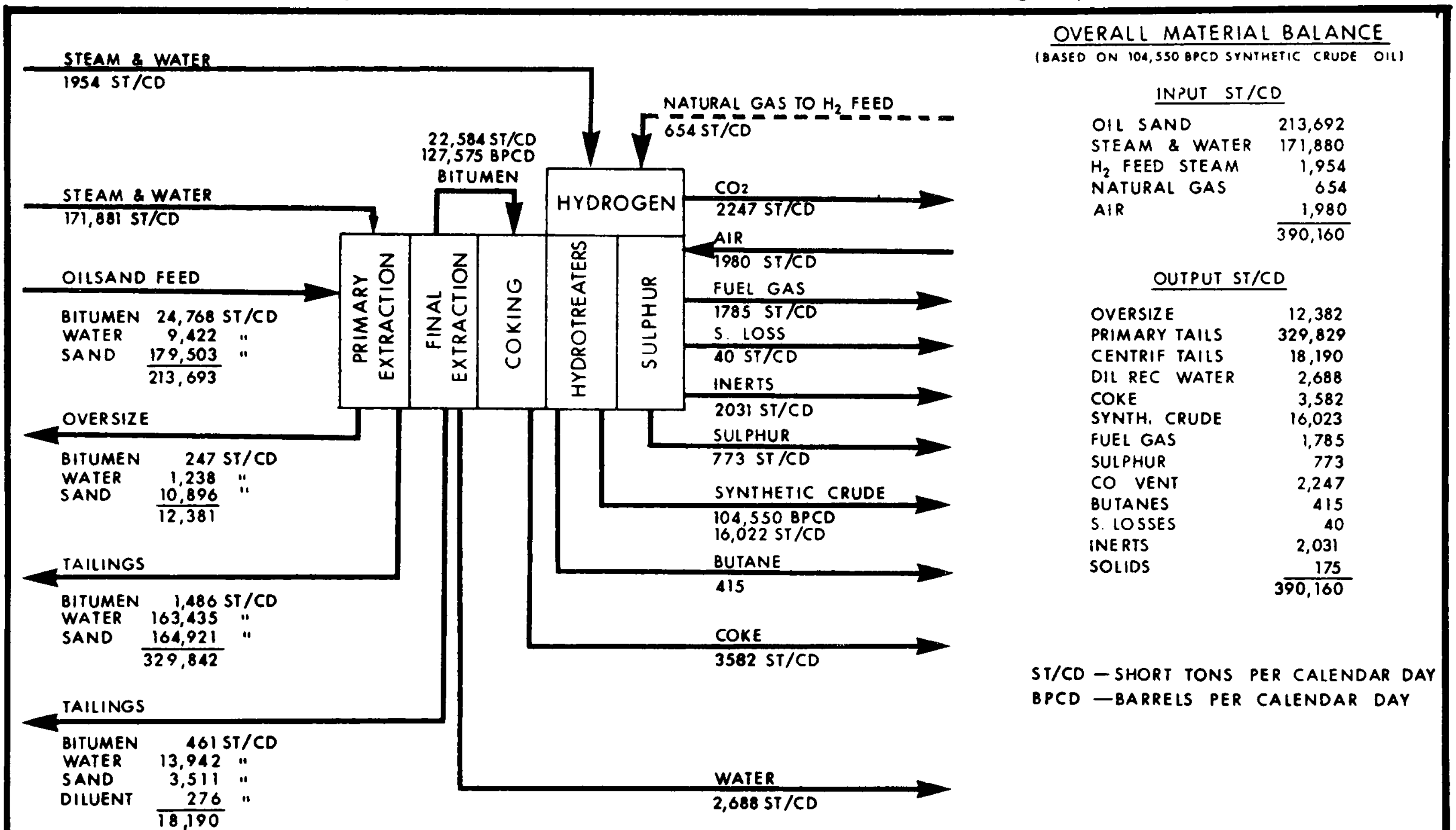


Figure 1

SYNCRUDE CANADA, LTD.

EXTRACTION AND UPGRADING SCHEMATIC FLOW SHEET

TABLE 1

RECOVERY EFFICIENCIES - UPGRADING PROCESSES
INCLUDING HYDROTREATING

Process	Recovery Efficiency	
	Per Cent By Weight	Per Cent By Volume
Hydrovisbreaking	76.0	89.5
Fluid coking	70.9	82.0
Delayed coking - Syncrude Canada	67.0*	78.5
Delayed coking - Great Canadian	65.0	76.5

*Estimated

TABLE 2

COMPARISON OF RECOVERY EFFICIENCIES
(based on total bitumen in place)

Step	Recovery			Product	Cumulative Recovery		
	Syncrude Canada		Great Canadian		Syncrude Canada		Great Canadian
	1971	1973	1973		1971	1973	1973
Weight Per Cent							
Mining	88	87	80	plant feed	88	87	80
Extraction and Froth Treatment	92.9	91	90	crude bitumen	82	79	72
Upgrading	76	71	65	synthetic crude oil	62	56	47
Volume Per Cent							
Mining	88	87	-	plant feed	88	87	-
Extraction and Froth Treatment	92.9	91	-	crude bitumen	82	79	-
Upgrading	89.5	82	-	synthetic crude oil	73.2(1)	65(2)	-

(1) Gravity of synthetic crude oil: 33 degrees API
(2) Gravity of synthetic crude oil: 30 degrees API

experienced by GCOS. The overall energy balances of the two plants is indicated in Table 3.

The sulfur recovery section of the Syncrude facility is viewed as being capable of achieving a 95% recovery efficiency on a continuous basis. The Board disagrees with Syncrude's position that their acid gas quality is "unfavorable" and considers the gas quality as "favorable". Under the sulfur recovery guidelines for gas processing plants in the Province established in ERCB Information Letter IL 71-29, the Syncrude sulfur plant should be 98% efficient, an achievement not technically feasible without tail gas clean-up. Based on current sulfur prices, the Board succumbed to the economic reality that a tail gas clean-up facility, estimated to require approximately $2 million in additional capital and $200 thousand in annual operating costs, could not be justified to reduce sulfur emissions by 30 TPD. The Board thus permitted Syncrude a waiver under their guidelines noting that even without tail gas clean-up the sulfur plant would still meet the air quality criteria of the Department of Environment.

The stockpiling of excess coke produced in the fluid coking upgrading process represented a concern to the Board in that it constitutes an energy resource which will not be used in the plant as now contemplated. It was recognized that this coke, containing 9% sulfur and 6% ash, does not represent a premium fuel, particularly since a reliable and economically feasible method of stack gas sulfur removal does not exist. Furthermore, no process is yet available for gasifying the bitumen coke. The Board thus accepted Syncrude's plan to stockpile the coke until an economically justifiable means of utilizing it is available. The Board also examined the power plant application of Syncrude with a view to future utilization

TABLE 3

ENERGY BALANCE

MINING, EXTRACTION, UPGRADING AND POWER PLANT

	Energy (10^9 Btu per calendar day)	Per Cent Syncrude Canada	Per Cent Great Canadian
Input Streams			
Bitumen Mined	830.1	95.2	96.6
Natural Gas	41.0*	4.7	3.4
Electrical Energy	1.2	0.1	
	872.3	100.0	100.0
Output Streams			
Synthetic Crude Oil	585.4	67.1	58.9
Excess Coke	57.7	6.6	3.5
Sulphur	6.2	0.7	0.5
Extraction Losses - Crude Bitumen	73.5	8.4	37.1
- Naphtha	10.4	1.2	
Heat Rejected and Electric Energy	139.1	16.0	
	872.3	100.0	100.0

* Up to 52 x 10^9 Btu per calendar day may be required at the final plant production rate of 125,000 barrels per day.

\- Based on a production rate of 104,550 barrels of synthetic crude oil per day.

of the coke as discussed in subsequent paragraphs.

Reiterating its concern over the ability of Syncrude to operate the tailings pond with no accumulation of water after the first three years of operation, the Board has included verbatim in their form of Approval, clause 3 of the former Approval, No. 1725. This clause requires Syncrude to satisfy the Board that it would be economically feasible to dispose of the tailings and overburden from the initial tailings disposal area and to propose alternative initial tailings disposal plans to minimize impairment of oil sands recovery in the area.

Power Plant Application Approved With Reservations On Nonuse of Coke

The second application of Syncrude considered by the Board involved the proposed on-site power plant which, although a part of prior applications, was regarded as a separate plant under the Hydro and Electric Energy Act which became effective on June 1, 1971. The concerns expressed by the ERCB regarding this application included, again, the fact that the bitumen coke was not to be used as a fuel as well as the proposed tie-in to the Provincial interconnected electrical system.

The Board, in reviewing Syncrude's current plans to use fuel gas instead of the coke as the power plant fuel as was proposed in their 1971 application, analyzed several options to avoid stockpiling of the bitumen coke. Although accepting Syncrude's estimate of $50 million as the incremental cost of a coke fired power plant over a gas fired facility, the ERCB determined that a coke burning plant was not only technically feasible (GCOS experience) but could also be economically competitive if stack gas clean-up was not required and ambient air quality standards were met through the use of an extra high stack. The Board ruled out this possibility nonetheless because of the high probability of other oil sands plants being built in the area. The cumulative sulfur emissions, when added to the 200 TPD additional from the Syncrude plant if the power plant were fueled by coke, were viewed as not in the public interest.

Other alternatives considered by the ERCB were utilization in one case of 60% of the net coke produced and in another case 45% in a dual-fueled facility. Even with only partial use of coke, the sulfur emissions would increase by increments of between 80 and 110 TPD, which levels were also viewed as not being in the public interest.

Electrical load swings caused by the cyclic operation of the two 120-cubic yard draglines used in the mining operation and initial start-up electrical requirements were cited by Syncrude as the reason for the interconnection to the Provincial electrical systme. Although bolstered by testimony offered by Alberta Power during the hearings that electrical load swings would not have an adverse effect on the Provincial system, the Board expressed reservations on this matter and telephone communications interference which might occur as a result of the intertie. In view of the fact that the interconnection is the subject of a separate application by Alberta Power, a decision for which has yet to be issued, the Board did not make a final ruling on the question of the intertie. They did urge Syncrude and/or Alberta Power to study the matter further.

Comment

The recommendation by the Board for approval of the Syncrude applications is expected to be accepted by the Province without change. The approval of these applications, while welcomed by Syncrude, must surely be little consolation to them in light of the numerous questions growing out of their letter agreement with the Province on royalties, a subject reviewed elsewhere in this section of this issue. Notwithstanding the controversy between the Federal and Provincial governments on the issue of tax and royalty treatment of oil sands, the Board continues to assess applications within the bounds of technical and economic practicabilities. The fact that possible cumulative SO_2 emissions overruled the conservation of energy (in the form of bitumen coke) in this instance should be clear evidence that the ERCB, at least, anticipates continued development of the Athabasca oil sands.

# # # #

SYNCRUDE ENTERS INTO LETTER AGREEMENT WITH ALBERTA

The Alberta Minister of Mines in a letter agreement dated September 14, 1973 to Imperial Oil, Ltd., Canada-Cities Service Ltd., Atlantic Richfield Canada, Ltd., and Gulf Oil Canada, Ltd. set forth the terms under which the Syncrude group could proceed with their 125,000 BPCD oil sands project. The agreement is essentially a letter of intent providing for the preparation of a mutually satisfactory "Definitive Agreement" forthwith. The text of the letter is reproduced in the appendix geginning on page A-67, and along with governmental actions bearing on the situation, is reviewed in the following paragraphs.

Canadian Participation Through Provincial Corporation and Syncrude Directorship

As a matter of policy the agreement requires Syncrude to employ and buy within the province to the maximum extent practicable. At least one director of Syncrude must be a Canadian resident of Alberta. This only confirms similar terms in the approval of the oil sands plant issued by the province in February of last year (see June 1972 issue of Synthetic Fuels, p. 3-14).

Under the agreement the Province may acquire from 5 to 20 percent interest in the project for cost plus interest at 8% and, at its option, may sell all or part of its interest to the people of Alberta. The entity which will hold Alberta's share and in which Albertans may purchase stock is The Alberta Energy Company (AEC). The pipeline will be 80% owned by the AEC with the remaining 20% by Syncrude. The power plant will be 50% owned by the AEC. Shares in the Alberta Energy Company will be offered in 1974 preferentially to Alberta residents and then to other Canadians. The $50 to $75 million worth of shares in the AEC to be offered will be matched by the government of Alberta to retain 50% ownership. No single holding of these shares may exceed 2% of the total.

Royalty Provisions

Crown royalty is set at 50% of the excess of gross revenue over expenses before income taxes. For purposes of computing this profit figure, usual direct operating costs are allowed as well as straight line depreciation of capital, an 8% percent per annum interest on construction costs up to $90,000,000, and 8% per annum of 75% of average capital employed in lieu of any actual interest paid. Capital costs committed before the fifth anniversary of the start of production will be depreciated on a straight line basis over 20 years starting on the fifth anniversary of the start of production. Capital costs incurred subsequently will be depreciated from the date they are incurred to the 25th anniversary of the start of production. Losses may be carried forward. At any time after the fifth anniversary of the start of production Alberta may change the basis of royalty to 7-1/2% of gross production. Having once done so, the Province may never change back to the 50% of net basis. The detailed mechanics of royalty payment will be governed by the "Accounting Manual" which will be a part of the "Definitive Agreement" for the Syncrude project.

Foster Economic Consultants Ltd., using cost figures furnished by Syncrude and their own admittedly pessimistic forecast of future crude prices prepared an estimate of Alberta's share of the profits from the Syncrude Project. This along with their comments on the principal risk areas in the project are reproduced in the appendix beginning on page A-79. Their calculation provides a clear illustration of the royalty provisions of the agreement. Using the figures they give, the discounted cash flow rate of return to Syncrude before any income taxes is calculated to be 4%. Foster's projection of crude price which was made before the outbreak of war in the Middle East starts with $4.85 per barrel in 1978. If Foster's estimated crude prices are increased 50% and 100% the DCFROR's before income taxes become 10% and 14% respectively.

Assuming that the cost figures used are reasonable, it appears that Syncrude is relying heavily on an increasing spread between crude prices and production costs to make the project financially attractive. Federal income tax treatment of the royalty payments to Alberta will be clarified in a ruling by Ottawa which was originally to have been made on November 16 but which has now been postponed until December 16 of this year.

Effect of Governmental Actions

By Canadian tradition, royalty on mineral production on Crown lands has been paid to the provinces. Early in September the federal National Energy Board imposed an export tax on Canadian crude leaving the country of $0.40 per barrel. This represented a departure from past practice and caused considerable stir in Alberta. In October the amount of the tax was raised to $1.90 per barrel, effective December 1, 1973.

Ottawa's apparent intention was to equalize the Chicago price of Canadian Crude with rapidly rising prices for Venezuelan and other non-North American crudes without penalizing Canadian consumers. No exception has as yet been made for synthetic crude oil nor is any indicated by the National Energy Board although the Syncrude group has stated their need for such relief. The letter agreement clearly states that it is subject to the condition "that the Federal Government does not regulate directly or indirectly the prices of synthetic crude oil below the levels attainable in a free international market." It is difficult to envision how this condition can be satisfied.

Premier Lougheed of Alberta has said in response to the imposition of the federal export tax that he will change the basis of the provincial royalty from actual sale price of the crude to a deemed world price for crude oil. The royalty would thus float with fluctuating crude prices. The implementation of this change in royalty requires legislation to repeal the revenue plan of July 1972 and replace it with the new regulations. This will be accomplished at the end of 1973 or as soon thereafter as the necessary legislation can be enacted. It is presently unclear as to whether the new legislation would change the royalty formula for GCOS, but there are no indications that it would not. In that the proposed royalty formula for the Syncrude Project is based on profit it might be allowed to stand although this is less than certain.

Since the attractiveness of the venture is apparently dependent on a widening spread between the U.S. crude price and production costs, the project will not be successful if the Canadian Federal Government whittles away at the increasing spread with an export tax. Canadian journals have voiced speculation that the actual intent of the export tax is to facilitate nationalization of the Alberta tar sands. This concept is lent credence by the obvious lack of cooperation and candor between the Provincial and Federal agencies involved. The British North America Act confers exclusive resources powers upon the Provinces with several important exceptions, one of which, Section 92, Subsection 10C follows:

"Such works as, although wholly situated within the province, are before or after their execution declared by the Parliament of Canada to be for the general advantage of Canada or for the advantage of two or more of the provinces."

Application of this subsection in the past has been to declare railways, canals and grain elevators under federal jurisdiction. If applied to the tar sands, ownership of the resource would remain with Alberta but the federal government would take sole charge of their development and the overall manner of their use. This would require an act of both houses of Parliament. With ownership, Alberta might retain some power in setting royalty levels. Feelings in both Alberta and eastern Canada are running high. Meanwhile, federal Energy Minister Donald McDonald has firmly denied any intention on the part of the government to invoke this Act or by any other means to take control of the oil sands from Alberta.

Syncrude Continues With Efforts Despite Uncertainties

An $891,000 contract for construction of a 500-man construction camp and mining equipment warehouse has been awarded to ATCO Ltd. of Calgary. The camp is to be in place by the end of this year.

Permits were granted to Syncrude by Alberta's Department of the Environment on November 6 under the Clean Air and Clean Water acts. Under terms of these permits, Syncrude must recover 95% of the sulfur entering the plant and the stack must be 600 feet tall. Half-hour ground level concentrations in micrograms per cubic meter must not exceed 525 for SO_2 or 400 for oxides of nitrogen. Particulates emmitted must not be more than 0.2

pounds per 1000 pounds of gaseous effluent.

Despite a great many uncertainties introduced by the lack of a clear tax and royalty policy, Syncrude gives every appearance of moving forward toward a point of no return. At present, however, the political environment under which it will proceed can only be labeled cloudy.

# # # #

GCOS PRODUCTION INCREASE APPLICATION RECEIVES ERCB APPROVAL RECOMMENDATION

The application by Great Canadian Oil Sands seeking authorization to increase their annual production from 16,425,000 barrels (45,000 BPCD) to 23,725,000 barrels (65,000 BPCD) has finally been resolved by the ERCB with their issuance on November 20 of ERCB Report 73-N-OG recommending approval of the application. The GCOS application and the subsequent Board hearing thereon were described in the March 1973 issue of Synthetic Fuels (p. 3-5). The Form of Approval recommended by the Board is reproduced in the Appendix beginning on page A-85. Formal approval is expected by the Lieutenant Governor in Council by the end of the year.

The Board reached its decision on the application on June 18 but its release was withheld until November awaiting confirmation of the Board's findings and recommendations on environmental matters by the Department of Environment. This fact, along with others discussed later, points to the increasing concern of the Board on environmental matters.

Reviewed in the following paragraphs are the significant points covered by the Board's report. Before proceeding to that review, however, it is considered appropriate to note the effect this approval will have on GCOS operations during 1974.

During the calendar year 1972, GCOS overproduced (in excess of allowable plus carryover underproduction from prior years) by the equivalent of 1,500 BPCD which constituted a debit to 1973 production. Thus for this year, GCOS had an allowable of 43,500 BPCD (45,000 less 1,500). During the first nine months of 1973 GCOS actually produced 47,985 BPCD. Assuming that this same production average can be sustained for the full year (a high probability), GCOS would enter 1974 with a further debit of 4,485 BPCD (47,985 less 43,500) which, absent the approval, would have permitted them (theoretically) to produce only 40,515 BPCD (45,000 less 4,485) in 1974. The approval will permit the plant to operate at 60,515 BPCD (65,000 less 4,485) without violation of their production authorization. GCOS has indicated that production contemplated in 1974 would average 59,000 BPCD.

Mine & Plant Operational Changes Noted

Only modest additions to the mining and conveying equipment are planned by GCOS to meet their new production allowable; however, GCOS has taken steps to increase the minable reserves to support the operation by:

- Subleasing a portion of lease No. 17 from the Syncrude group containing approximately 100 million barrels of bitumen. The area subleased is shown in Figure 1.

- Acquiring an exemption from section 1 (a) of the regulations under the Quarry Regulation Act permitting an arrangement with Standard Oil of BC for maximizing mining recovery in the common boundary area. (See Figure 1.)

Reflecting the concern of the Board that GCOS will only realize a mining recovery of 80% on lease 86, continues to consider as reject, oil sands containing less than 8% bitumen by weight and limits mining to areas where the overburden-to-pay ratio is 1.0 or less, GCOS is being expressly required to obtain approval of a detailed mining plan for each year in advance. This requirement, however, merely formalizes a common practice in recent years.

GCOS does not require modifications to the extraction plant for the higher level of production. The upgrading operation will require only the addition of a stripping tower to treat the extracted bitumen prior to delivery to the delayed cokers. Light ends recovered in the stripper would presumably be delivered directly to the Unifiners thereby reducing the load on the cokers which are claimed to

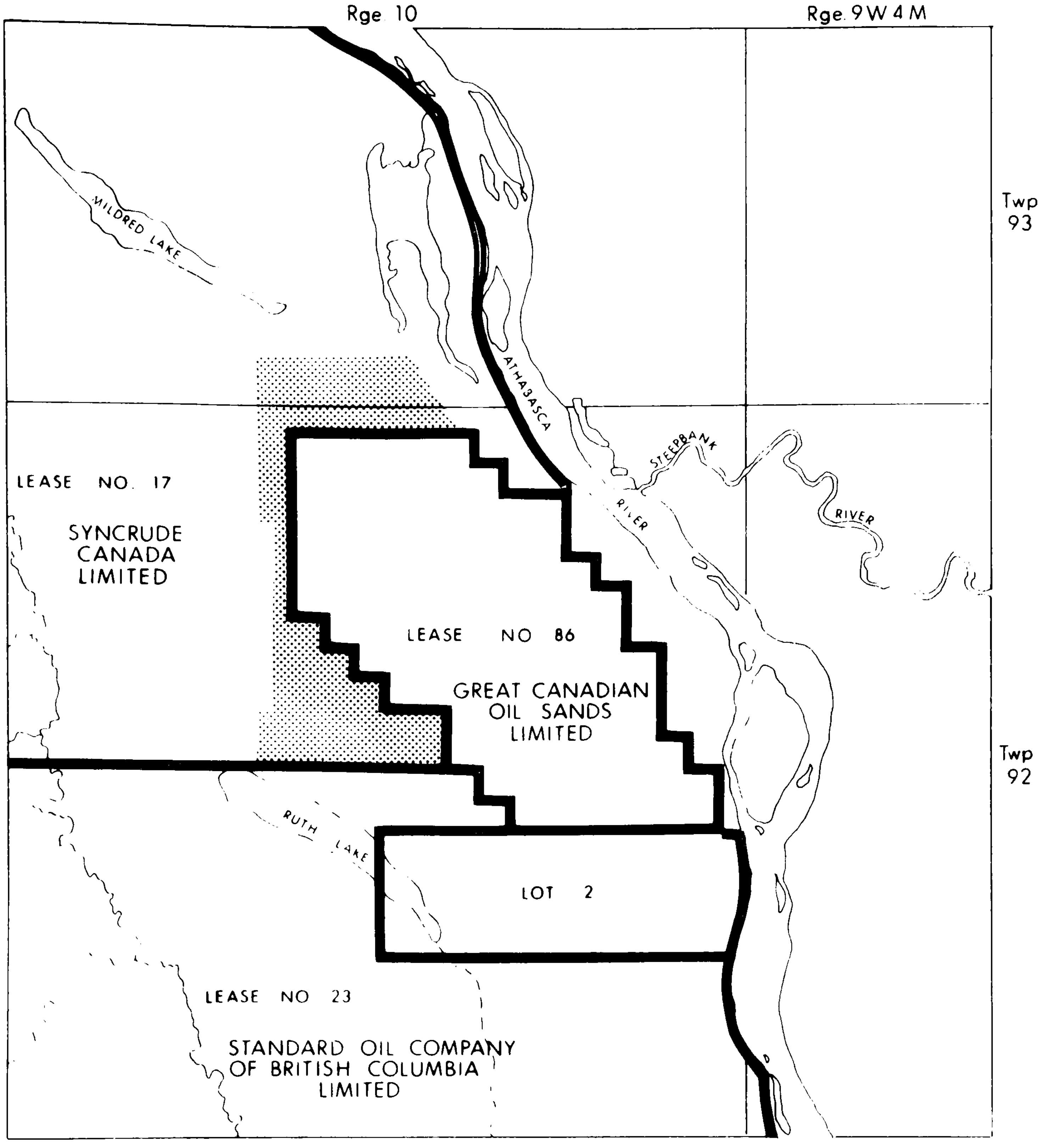


FIGURE 1 - MINING AREA

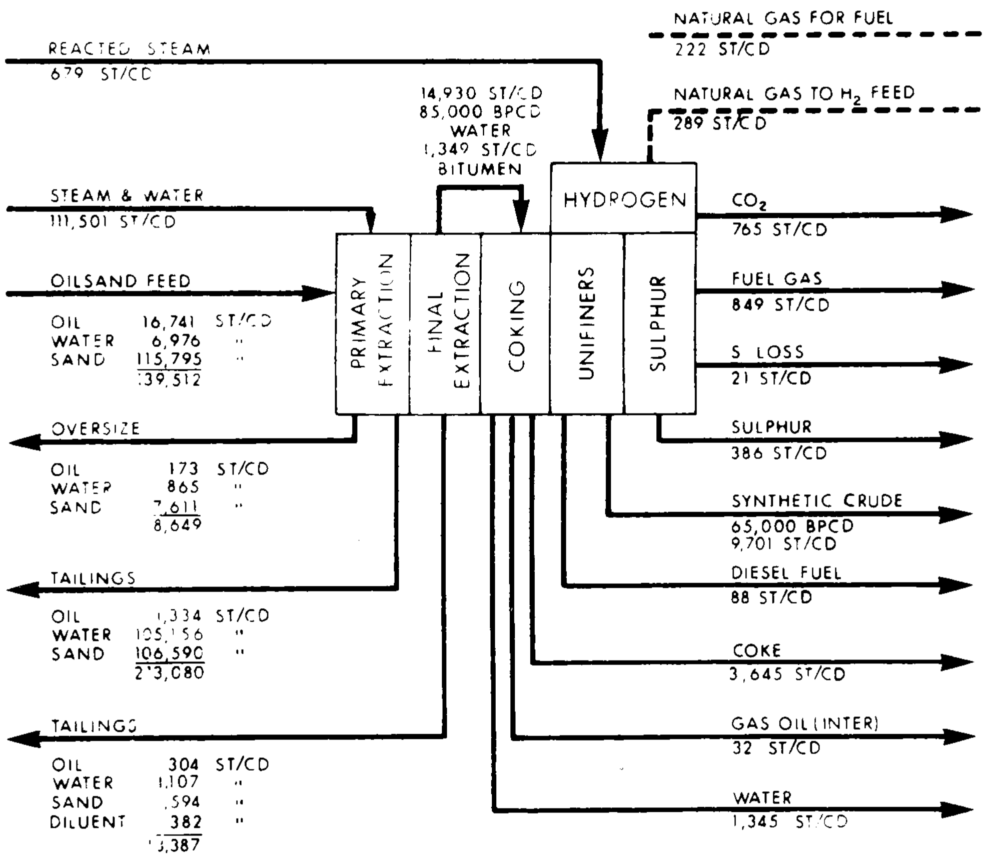
AREA OF LEASE NO 17, SUBLEASED BY GREAT CANADIAN have the least excess capacity of any system in the plant. A flow sheet depicting stream flows at the 65,000 BPCD rate in the extraction and upgrading areas is shown in Figure 2.

One problem noted by the Board is the increase in the quantity of stockpiled (unused) coke under the expanded operation while natural gas demand increases almost proportionally from 16.5 MM SCFD at 45,000 BPCD to 22 MM SCFD at 65,000 BPCD. No market for the excess coke has been located and it must thus be viewed as an unused energy source. The overall energy balance for the 65,000 BPCD production rate is indicated in Table 1 and points to the fact that energy unused in the form of coke is slightly in excess of that required in the form of natural gas. As a consequence, the Board is requiring GCOS to submit a study to the Board by June 30, 1974 regarding the feasibility of using coke to replace that portion of natural gas used for fuel which is 43% (9.5 billion Btu/CD) of the total natural gas requirement, the balance being used as hydrogen plant raw material. If such were feasible, the overall energy efficiency of the plant as measured by the percent of input energy represented by the synthetic crude product would increase from 58.9 to 59.8.

While noting with some concern the reduced mining recovery being experienced by GCOS in their mining operations over the recovery estimated in 1963 at the time of their original application, the Board commended the company for achieving recoveries in excess of estimates in the extraction and upgrading areas. Table 2 indicates the comparable recovery efficiencies by processing step and cumulatively. Note that GCOS is cumulatively recovering 2% more than originally estimated even with the reduced mining recovery.

Environmental Concerns Emphasized In Report

The delay in release of the report, occasioned by the Department of Environment review noted earlier, can fairly be assessed as a sign of less than complete agreement between the Board and the Department on such matters. The fact that not one aspect of the Board's report was altered since its preparation in



OVERALL MATERIAL BALANCE
BASED ON 65,000 BPCD SYNTHETIC CRUDE OIL

INPUT ST/CD	
OIL SAND	139,512
STEAM & WATER	111,501
H_2 FEED STEAM	679
NATURAL GAS	238
	251,930

OUTPUT ST/CD	
OVERSIZE	8,649
PRIMARY TAILS	213,080
CENTRIF TAILS	13,357
DIL REC WATER	1,349
COKE	3,643
SYNTH CRUDE	9,701
FUEL GAS	849
SULPHUR	396
CO_2 VENT	765
G O DIESEL (USED)	120
S LOSSES	21
	251,930

ST/CD — SHORT TONS PER CALENDAR DAY
BPCD — BARRELS PER CALENDAR DAY

FIGURE 2 - EXTRACTION AND UPGRADING SCHEMATIC FLOW SHEET

TABLE 1

ENERGY BALANCE*

MINING, EXTRACTION AND UPGRADING STAGES (INCLUDING THE POWER PLANT)

	Energy (10^9 BTU per calendar day)	Per Cent
Input Streams		
Oil Sands	615.2	96.6
Natural Gas	21.8	3.4
	637.0	100.0
Output Streams		
Synthetic Crude Oil	374.8	58.9
Diesel Fuel	3.4	0.5
Excess Coke	22.5	3.5
Sulfur	3.1	0.5
Process Steam, Electric Energy and Losses	233.2	36.6
	637.0	100.0

*Based on a production rate of 65,000 barrels of synthetic crude oil per day.

June suggests that the Board is capable of prevailing in its views. We consider this to be an encouraging indication in that the Board has consistently manifested a willingness to temper environmental concerns with economic and technical realities. Nonetheless the emphasis placed on these concerns by the Board in the report and in the number of terms and conditions relating to such in the Form of Approval should be taken as clear evidence that oil sands operators must put forth maximum effort in these areas.

Sulfur recovery and emission control clearly represent the greatest of the environmental concerns followed closely by particulate emmissions. GCOS had been operating under Air Pollution Approval 365-P-508 which was being revised by the Board and the Department at the time GCOS submitted its application. That approval permitted ground level SO_2 concentrations of 0.40 ppm (equivalent to 354 LT/D of SO_2 at 700°F from the power plant stack and 44 LT/D of SO_2 at 1000°F from the sulfur plant incinerator stack). Particulate emissions were restricted to

TABLE 2

RECOVERY EFFICIENCIES - WEIGHT PERCENT

(Based on total crude bitumen in place)

Step	Recovery (%) 1963	Recovery (%) 1973	Description	Cumulative Recovery (%) 1963	Cumulative Recovery (%) 1973
Mining	89	80	Plant feed	89	80
Extraction and Froth Treatment	85	90	Crude bitumen	76	72
Upgrading	60	65	Synthetic crude oil	45	47

0.85 lbs. per 1000 lbs. of effluent, adjusted to 50% excesss air in POC. The Department now requires that ambient SO_2 concentrations not exceed 0.17 ppm on a 1-hour cycle or 0.2 ppm on a 1/2-hour cycle. The particulate matter standard for GCOS now rests at 0.2 lbs. per 1000 lbs. of effluent (50% excess air).

With regard to the effect of the new standards and the increased production rate on the power plant stack emissions the Board noted a discrepancy in the prior SO_2 measurements in the stack as compared to the amount of sulfur (5.75%) in the coke fed to the burner, the SO_2 measurement being consistently lower by 50%. The Board recommended that GCOS be permitted to emit 300 LT/D of SO_2 from the stack at 550°F minimum temperature. This quantity corresponds directly to the burning of 2900 ST/D of 5.75% sulfur coke at the 65,000 BPCD production rate. This recommendation is based on the fact that no technically feasible method for power plant stack clean-up is available. GCOS is required to resolve the discrepancy in stack measurements vs. sulfur input and report to the Board by March 31, 1974.

As to the SO_2 emissions from the sulfur plant, it is clear that this is controlled by the sulfur recovery efficiency of the Claus plant. The Board noted that, on the basis of guidelines for sulfur recovery efficiencies for gas plants as promulgated in 1971, the GCOS sulfur train should consist of a 3-stage Claus unit. This requirement is based on a "favorable" gas quality and 400 LT/D of sulfur into the sulfur recovery plant in accordance with Table 3. In contrast to the Board's judgement that the acid gas quality is "favorable", GCOS views it as "unfavorable"; a similar disagreement existed in the Syncrude approval discussed elsewhere in this issue. In the Board's view, the addition of a third stage to the GCOS Claus system would cost $500 thousand and increase operating costs by $40 thousand per year. Thus, coupled with the GCOS experience of being able to market less than 10% of its sulfur, the Board will not require GCOS to undertake the addition of the third stage. Instead, the Board has imposed a minimum sulfur recovery efficiency of 94% after December 31, 1974 and recommended that a license under the Clean Air Act be issued permitting a maximum emission of 48 LT/D of SO_2. Based on the substantial improvement in the recovery efficiency of the sulfur plant over the past several years, the Board apparently does not believe this to be an unreasonable demand. The theoretical maximum recovery efficiency is 95.5%. Thus the Board is waiving the sulfur guidelines for GCOS which they view as requiring a 96% recovery efficiency.

The Board concluded that GCOS would be able to operate within the new standards for ground level SO_2 standards based on the recommended maximum emission rates. The question of a cumulative effect on ground level concentrations with proposed plants was left to be resolved when the situation could be better assessed.

TABLE 3

MINIMUM SULFUR RECOVERY EFFICIENCY GUIDELINES
(From ERCB IL 71-29)

(Inlet rate LT/D)	Process Requirements	Required Recovery Efficiency for Various Acid Gas Qualities: Favorable	Average	Unfavorable
1000 to 4000	Stack clean-up required	98-99	98-99	97-99
400 to 1000	Minimal stack clean-up or equivalent process	96-98	95-98	94-97
100 to 400	Minimum of 3 stage Claus plant or equivalent process	94-96	93-95	92-94
10 to 100	Minimum of 2 stage Claus plant or equivalent process	93-94	92-93	90-92

As to particulate emissions, the Board must succumb to the published standards of the Department. GCOS must thus comply with the 0.2 lbs. standard notwithstanding the substantial expenditures which they testified would be required to comply with the new standard.

Other matters considered by the Board were land reclamation and water pollution effects of the production increase. In both instances the Board accepted the plans of GCOS but did require that a long term land reclamation plan be submitted for review by both the Board and the Department.

<u>Production Increase Qualifies Under Life Index Criteria of Oil Sands Policy - Royalty Yet To Be Resolved</u>

With a minimum of discussion, the Board accepted the GCOS contention that the production increase would qualify under the Life Index Criteria of the 1968 Oil Sands Policy of the Province. The critical life index range of 12-13 years for conventional petroleum would be reached by this year or next, in the Board's view. The Oil Sands Policy permits essentially unlimited synthetic crude production when the life index is in this range so long as conventional production is not in danger of being displaced in the market place by synthetic crude.

Notable by the absence in the report of any reference to a revised royalty schedule for GCOS, the economic viability of the plant remains uncertain. Although GCOS has indicated that they could operate profitably at 55,000 BPCD production with, no doubt, concurrent price increases, GCOS has, in fact, been receiving higher prices over the last two quarters for its production. Unfortunately, operating at a profit is not synonymous with economic viability and we remain convinced that some royalty alteration will be required -- similar to Syncrude or otherwise -- before GCOS can point to success on the financial page.

# # # #

SYNCRUDE PUBLISHES THREE ENVIRONMENTAL MONOGRAPHS CONCERNING LEASE 17

Syncrude Canada, Ltd. has released three monographs describing various ecological aspects of Bituminous Sands Lease No. 17 where the company plans to locate a 125,000 BPCD oil sands plant. Identified as Environmental Research Monographs (ERM), the publications released to date are titled:

- The Habitat of Syncrude Tar Sands Lease No. 17: (ERM 1973-1)
- Beaver Creek: An Ecological Baseline Survey (ERM 1973-2)
- Migratory Waterfowl and the Syncrude Tar Sands Lease: A Report (ERM 1973-3)

A fourth study entitled: Syncrude Lease No. 17: An Archaeological Survey is scheduled for release before the end of the year. Syncrude hired Renewable Resources Consulting Services Limited of Edmonton to prepare the studies and announced a policy of making the reports available to government agencies, the scientific community, and citizens of Alberta having an interest in oil sands resource management as related to ecological values.

The last two of the above-listed reports addressed the impact of the proposed oil sands plant on the ecological elements studied. In the first report, the effect of the proposed development on the fish in Beaver Creek was concluded to be minimal. One recommendation, however, was to construct a retention pond and dam downstream of the mining area (between the mine and the Athabasca River) to preclude the use of the upper reaches of the creek as a spawning and rearing area by Artic grayling, as now occurs. Beaver Creek runs NNW through the lease to the Athabasca River, roughly bisecting the proposed mining area.

The study on water fowl in the lease area concluded that a potential problem could arise due to ducks using the tailing pond which will be contaminated with oil. The report noted that scaup were far more vulnerable in this regard than were mallards. Mallards are capable of recovering after cleaning but the scaup do not live, apparently due to a loss of buoyancy and inability of their system to compensate for loss of feathers (insulation).

It was further noted that, although waterfowl population in the area was substantial, some evidence indicated that the waterfowl avoided the existing GCOS tailings disposal pond. Only two oiled ducks (loons) have been noted at the pond in five years according to a GCOS official interviewed for the study. The report concluded by recommending mitigating measures such as periodic firing of carbide cannons to discourage landings and improving the attractiveness of non-polluted water bodies to encourage the waterfowl to discriminate in favor of the latter.

# # # #

IV
coal

USGS DELINEATES KNOWN COAL LEASING AREA IN POWDER RIVER BASIN

The U. S. Geological Survey recently completed its classification of Federal lands in the Powder River Basin of Wyoming. Effective as of May 25, 1973 the Powder River Basin known coal leasing area was established as subject to the competitive coal leasing provisions of the Mineral Leasing Act of 1920, as amended (20 U.S.C. 201).

A plat showing the boundaries of the known coal leasing area is reproduced as Figure 1 on page 4-2. The total area subject to lease within this area is approximately 3,951,486 acres.

The effect of this action is that no prospecting permits will be issued for the known coal leasing area and that competitive coal leases will be issued only at the discretion of the Secretary of Interior.

# # # #

TURCOTT DESCRIBES FUTURE BLM LEASING POLICY

George L. Turcott, Associate Director Bureau of Land Management, delivered a speech before the Denver Coal Club on September 11, 1973 in which he outlined the procedures BLM would follow regarding establishment of long term coal leasing policies.

Turcott stated that the important elements of minerals program management are inventory, planning, allocation, and rehabilitation. Presently, BLM is primarily concerned with the allocation of energy minerals for which a new system called EMARS (for Energy Minerals Allocation Recommendation System) is being developed.

EMARS is a process for relating availability of Federal coal deposits to national and regional energy needs through a model development technique. By this technique BLM will determine the size, timing, location and rehabilitation potential of future coal leases.

The first step of EMARS is to make a quality-cost index classification of coal resources. The BLM in cooperation with the Geological Survey will classify coal deposits according to their thickness, quality, overburden depth, areal extent, potential depth of deep mine operations, mineability, and mining costs. This type of classification will be made both for federal coal lands that have been leased and for those to be offered for future leasing.

Next, national and regional energy demands are being assessed through the many available models and projections. Finally, the susceptibility for rehabilitating mined areas is being analyzed. Studies related to revegetating spoils banks under various physical, chemical and climatic conditions are currently being conducted in Montana. Ground water will also be monitored to establish what effect mining operations will have upon it.

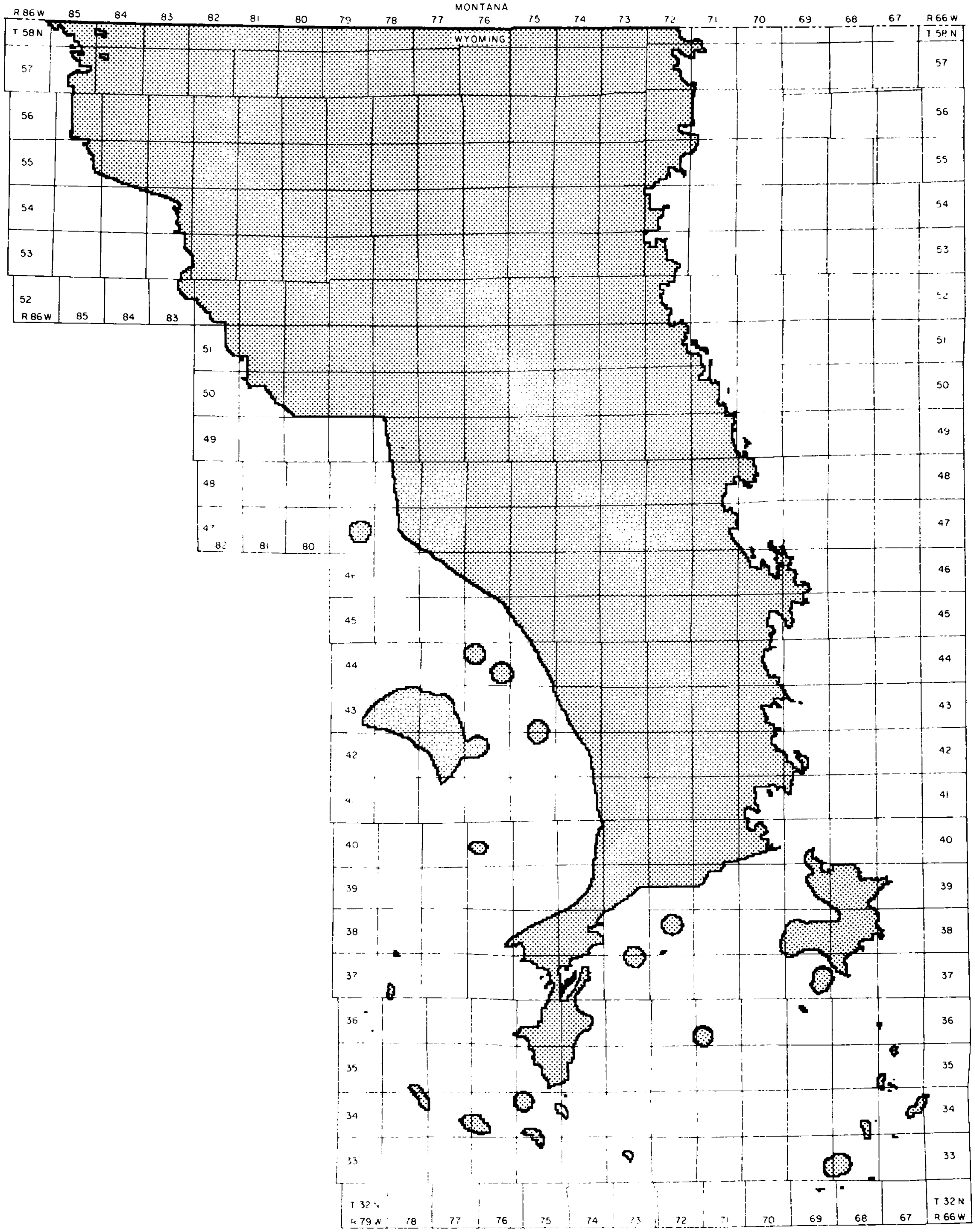
Once the needs for additional coal leases are established by the EMARS procedure they will be processed through the BLM land use planning system with provisions for industry nominations before lease sites are determined. Turcott stated that areas will be considered for leasing only where they are assured of an adequate, specific rehabilitation technology; where water quality and supply requirements can be met; and where transportation and economic factors will promote prompt utilization of the coal resource.

This pre-planning of reclamation requirements is seen as one of the keys to making specific sites available for coal leasing. A specific rehabilitation objective will be chosen from those available for the site and then a determination of mining sequences, and surface and water management requirements will be made in order to meet that objective. Also, costs of achieving that specific rehabilitation objective will be calculated. By doing this before offering coal lands for competitive leasing, all bidders will know how they must perform, and everyone will be able to see if rehabilitation ojectives are being met.

FIGURE 1

POWDER RIVER BASIN KNOWN COAL LEASING AREA

Tps. 32-58 N., Rs. 66-86 W., 6th P. M., Wyoming



Once areas for leasing are identified, 5- to 10-year schedules for lease sales can be prepared and reclamation procedures can be pre-tested so that areas can be avoided where rehabilitation would not be effective. This long-term leasing program will allow the Department of Interior to shift from an ad hoc system of issuing coal leases to a deliberate approach to meet national objectives. Hopefully, a 5-year lease schedule will be established by June 1974. Such an approach to leasing will allow industry to perform advance planning.

This long-term approach to coal leasing is in line with the policy Secretary Morton announced in February of this year. (Please refer to page 4-24 of the March 1973 issue of Synthetic Fuels for a discussion of that policy). An additional stipulation of Morton's announced coal leasing policy was the preparation of an environmental impact statement on leasing as required by NEPA.

This environmental impact statement is in preparation and a draft statement is scheduled for submission to CEQ in the near future. This statement is expected to present in general terms the environmental results of the coal program, but it is not intended to negate entirely the need for impact statements on a regional basis, or for individual leases in some instances. In particular, the statement will not, according to Turcott, eliminate the need to prepare environmental impact statements on major Federal rights-of-way or permits necessary to develop private coal resources.

Turcott pointed out that past experience with NEPA indicates that lead times of one to several years are necessary for Federal actions in order to complete required environmental analyses and to prepare environmental impact statements. For this reason, it will be important for companies to establish an early relationship with BLM and other Federal agencies so that contract commitments can be met.

Medicine Bow Mine Affected

One of the first projects to be affected by the new BLM policies is the proposed opening of Medicine Bow Coal Company's three million ton per year mine near Seminoe Reservoir in Carbon County, Wyoming near Hanna.

Although initial operation would be on fee lands, the mine would eventually disturb an estimated 4,000 acres of which 1,200 acres would be national resource lands which are intermingled with the private fee land. These 1,200 acres are covered by a yet to be issued competitive coal lease, W-25807. In order to begin operation of this mine, right-of-way permits across national resource lands for the necessary power line, access road and rail spur must be obtained from BLM.

In July, the BLM office in Rawlins completed an Environmental Analysis Report for the proposed action of granting rights-of-way for a road and powerline to the Medicine Bow Coal Company Mine. In this report BLM stated that the approval of these rights-of-way would be, in effect, approval of the mining operation and would tend to commit BLM to favorable action on subsequent rights-of-way involving national resource lands as well as the leasing of intermingled federal coal lands. Because of this close relationship between the granting of rights-of-way and the mining operation, BLM attempted to assess the overall impact of the entire mining operation in its report.

The report in a superficial way assessed the impact of the proposed mining operation and proposed mitigating stipulations which should be followed by Medicine Bow. It then concluded that if certain mitigating stipulations were followed, then the granting of the necessary right-of-way permits and issuance of the federal coal lease would not be a major federal action significantly affecting the quality of the human environment and an impact statement, as provided by NEPA, was not required.

This report was submitted to the Washington office of the Bureau of Land Management and subsequently returned to the Rawlins office in late October for a more comprehensive analysis on resource information and a new proposed alignment for a railroad spur to the site. This restudy was to be completed and resubmitted to the Washington office within 30 days.

# # # #

PAUL AVERITT CLARIFIES COAL RESERVE VALUES

Many different estimates for U.S. coal reserves and their availability have been cited by legislators and various authors. Some of these estimates have been either used out of context or inaccurately quoted.

Paul Averitt of the U.S. Geological Survey was asked to clarify the reserves situation and to give his estimate of the coal reserves available for the rest of this century at a meeting of the Denver Coal Club on November 13, 1973. He responded as follows:

> "The total coal in place to a depth of 6000 feet below the surface, determined by mapping and by estimates in unmapped areas, in beds at least 14 inches thick for anthracite and bituminous coal and at least 2-1/2 feet thick for subbituminous coal and lignite, is 3.2 trillion tons.
>
> "The coal in place with the same seam restrictions to a depth of 3000 feet which has been proven by mapping and exploration amounts to a little less than 1.6 trillion tons.
>
> "Of this 1.6 trillion tons, only one-fourth, or 400 billion tons, is within reach of mining equipment and the economics anticipated by the year 2000.
>
> "Much of the 400 billion tons will be lost in the mining operation and the suggested value for recoverable coal available to the end of the century is 250 billion tons."

The value of 3% used by some when comparing strippable coal reserves and total coal reserves refers to the total coal in place. If used to compare with recoverable coal, the percentage is much greater.

Accepting Paul Averitt's value of 250 billion tons how do coal reserves compare with proven oil and gas reserves? According to the AGA and API, the proven reserves at the end of 1972 were 36.3 billion barrels of crude oil, 266 trillion cubic feet of natural gas and 6.8 billion barrels of natural gas liquids. Using heating values of 22 MM Btu/ton for coal, 1000 Btu/cf for natural gas, 5.8 MM Btu/bbl for crude oil and 4.6 MM Btu/bbl for NGL, the resulting estimates are given in Table 1.

TABLE 1

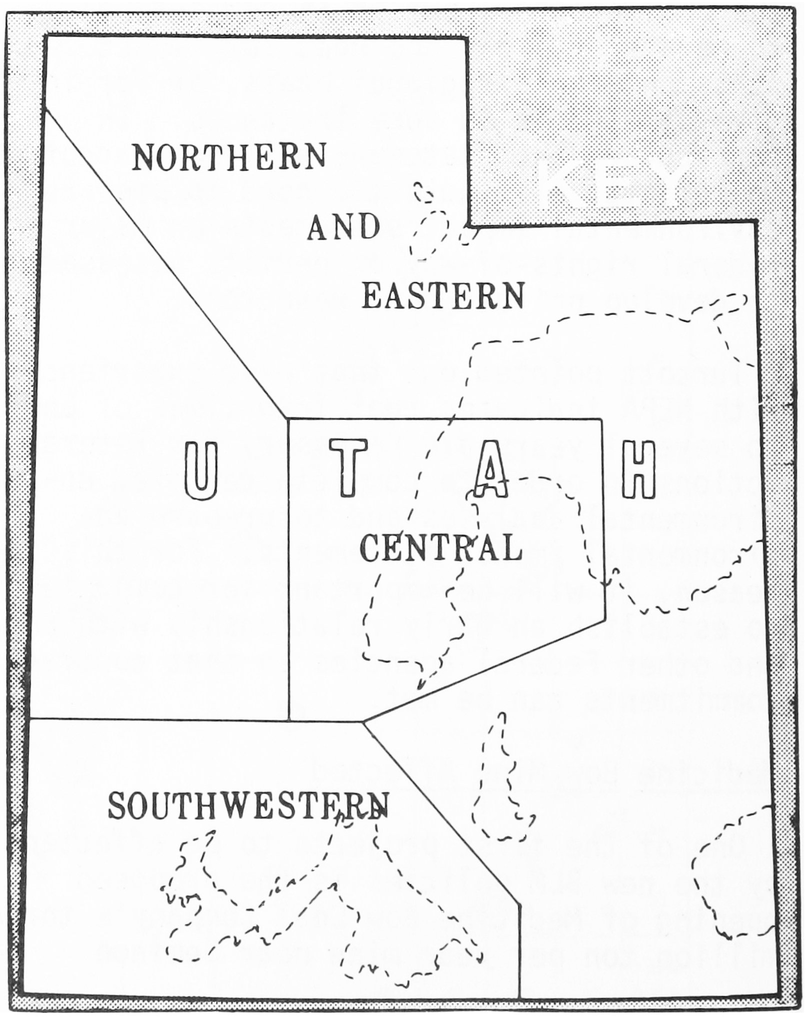
Proven Reserves of Various Fuels

Fuel	10^{15} Btu	% of Total
Coal	5500	91.7
Crude Oil	211	3.5
Natural gas liquids	31	.5
Natural gas	266	4.3
	6008	100.0

# # # #

UTAH COAL DESCRIBED IN A SERIES OF MONOGRAPHS

A series of three monographs on Utah coal has been prepared by the Utah Geological and Mineralogical Survey. Mongraph Series No. 1 covers Southwestern Utah; No. 2 covers Northern and Eastern Utah; and No. 3 covers Central Utah as indicated on the map.



The monographs are hard-bound and contain a wealth of information on the geology of the coal areas, descriptions of the coal fields, reserves, mining conditions, coal mineral ownership, coal mineral control (leases), coal quality, water resources and economic considerations. In addition, Monograph No. 3 contains chapters on Palynomorphs found in Utah coal and an economic evaluation of Utah coal. The three volumes were made possible by a grant from the Environmental Protection Agency with matching funds from the State of Utah. The volumes cost $20 each and are available from:

Utah Geological and Mineralogical Survey
103 Utah Geological Survey Building
University of Utah
Salt Lake City, Utah 84112

# # # #

STATE LEASING PROVIDES MAJOR ACTIVITY

Leasing activities over the last 3-month period have been quite limited in all of the western states with the exception of Wyoming. This is due to suspension of Federal leasing and in some cases state leasing as a result of the Secretary of Interior's Order No. 2952. (See page 4-24 of the March issue of this report for a discussion of that order.)

Some of the transactions of note in Wyoming include the assignment of state leases on some 8,420 acres to Ark Land Co. and the issuance of state leases for large acreages to Denver Basin Resources, Robert David and W. Wilson. The above mentioned transactions plus all the leasing activities over the last 3-month period are listed following for the states of Colorado, Montana, North Dakota, New Mexico, Utah and Wyoming.

# # # #

WESTERN COAL LAND ACTIVITIES
(State and Federal Lands Only)

Name	Action	Acres	County
	COLORADO		
Cooley Gravel Co.	State lease issued	740	Jefferson
Neil, Glenn G.	State lease terminated	13,542	Adams, Arapahoe Morgan, Weld
Saba, Phosy L.	State lease assignee R. J. Hollberg, assignor	411	Larimer
	MONTANA		
Woodson, Fred C.	Fed. prospecting permit terminated	3,675	Dawson, Richland
	NEW MEXICO		
Eastern Associated Properties Corp.	State lease terminated	1,881	San Juan
	UTAH		
Armstrong, Dale	State lease assignee	427	Kane
Fehr, E. M.	State lease assignee Sonja McCormick, assignor	1,313	Carbon
Kanawha & Hocking Coal & Coke Co.	State lease assignee	1,030	Carbon

UTAH (Continued)

Name	Action	Acres	County
Kaiser Steel Corp.	Fed. lease application	440	Carbon
Peabody Coal Co.	State lease assignee Malcolm N. McKinon, assignor	120	Emery
Sanders, John F.	Fed. lease application	5,300	San Pete
Stevenson, Mary Lee	State lease terminated	3,851	Carbon, Emery
Stevenson, Wm. A.	State lease terminated	3,189	Carbon
Tanner, Meldon J., et al	State lease issued	640	Carbon
Utah Power & Light	State lease assignee Delcoal, Inc. & Rasmussen, assignors	3,840	Kane, Garfield
Utamex, Inc.	State lease assignee Noel Tanner, assignor	12,136	Grand, Carbon

WYOMING

Name	Action	Acres	County
Ark Land Co.	State lease assignee		
	Assignors: V. R. Volz	1,920	Lincoln, Johnson
	S. T. Coleman	1,278	Weston, Johnson
	F. R. Burkhardt	640	Johnson
	Leona Hagedorn	3,302	Johnson
	Rosita Trujillo	1,280	Johnson
		8,420	
Basil, Leslie R.	State lease issued	1,280	Sweetwater
Cassell, Jane P.	State lease issued	640	Sweetwater
Cassell, Merlin E.	State lease issued	640	Sweetwater
Castaldis, L. J.	State lease issued	640	Sweetwater
Conn, B. N.	State lease issued	640	Albany & Sweetwater
David R. W.	State lease issued	23,418	Sweetwater, Park, Carbon, Goshen
Denver Basin Resources	State lease terminated	14,066	Laramie
Ellis, R. E.	State lease issued	640	Sweetwater
Energy Development Co.	State lease terminated	2,560	Carbon
FMC Corp.	Fed. lease application	10,320	Sweetwater
Hanesworth, Mona M.	State lease issued	1,280	Albany
Hanesworth, R. Alan	State lease issued	1,920	Sweetwater
Harris, C. Metal	State lease issued	640	Sweetwater
Krider, M. A., et al	State lease issued	640	Sweetwater
Leonard, J. R.	State lease issued	640	Sweetwater
Lockhart, Marion	Fed. lease application	44,897	Campbell
Meadowlark Farms, Inc.	Fed. Competitive lease application	4,016	Campbell
Pattison, W. H.	Fed. lease application	45,278	Campbell

WYOMING (Continued)

Name	Action	Acres	County
Peterson, R. L.	State lease issued	1,241	Sweetwater, Campbell, Sheridan
Petty, C. L., et al	State lease issued	640	Carbon
Reibold, E. M.	State lease assignee Wm. Wilson assignor	6 640	Lincoln
Rose, Norma	State lease issued	80	Johnson
Sailor, V. R., et al	State lease issued	3,205	Sweetwater, Lincoln
Sherman, J. M., et al	State lease issued	640	Sweetwater
Stutzman, L. et al	State lease issued	640	Sweetwater
Tomlin, Fay E., et al	State lease terminated	320	Sweetwater
Tomlin & Hanesworth	State lease issued	320	Carbon
Wilson, W. M. & M. K.	State lease issued	23,526	Sweetwater
Wold, Jane P.	State lease terminated	5,840	Lincoln
Yonkoff & Wilson	State lease issued	640	Sweetwater
Yonkoff & Hanesworth	State lease terminated	640	Sweetwater

LITTLE MISSOURI GRASSLANDS STUDY NEARS COMPLETION

The Little Missouri Grasslands Study is aimed at formulating a multiple land use plan and supporting policies to guide future agricultural and industrial growth of a nine-county area of southwestern North Dakota. It is being conducted by North Dakota State University with assistance from local, state, and federal government agencies and private organizations. The study is to be completed by the end of 1973 at which time a final report will be issued. The final report will contain a recommended multiple land use plan and sugggested policies for implementation. The study outline was reviewed on page 4-33 of the September 1973 issue of Synthetic Fuels. Since that time, three additional interim reports have been published: Interim Report No. 3, "Conference on the Future of Agriculture in Southwestern North Dakota"; Interim Report No. 4, "Conference on Recreation and Tourism in Southwestern North Dakota"; and Interim Report No. 5, "Conference on Mining and Power Production in Southwestern North Dakota."

Ultimately, a total of six interim reports will be published in conjunction with the study. The report titles are as follow:

- Little Missouri Grasslands Study - Introduction and Relationship to Other Studies
- Conference on Property and Mineral Rights
- Conference on the Future of Agriculture in Southwestern North Dakota
- Conference on Recreation and Tourism in Southwestern North Dakota
- Conference on Mining and Power Production in Southwestern North Dakota
- Conference on Resources in Southwestern North Dakota

The interim reports are available from:

Little Missouri Grasslands Study
North Dakota State University
Fargo, North Dakota

# # # #

OCR ISSUES TWO REPORTS ON PROJECT GASOLINE

The contract between the Office of Coal Research and Consolidation Coal Company for Consol's coal liquefaction process, known as the Consol Synthetic Fuel Process or Project Gasoline, ended August 30, 1972 after nine years of life during which over $20 million was spent by Consol.

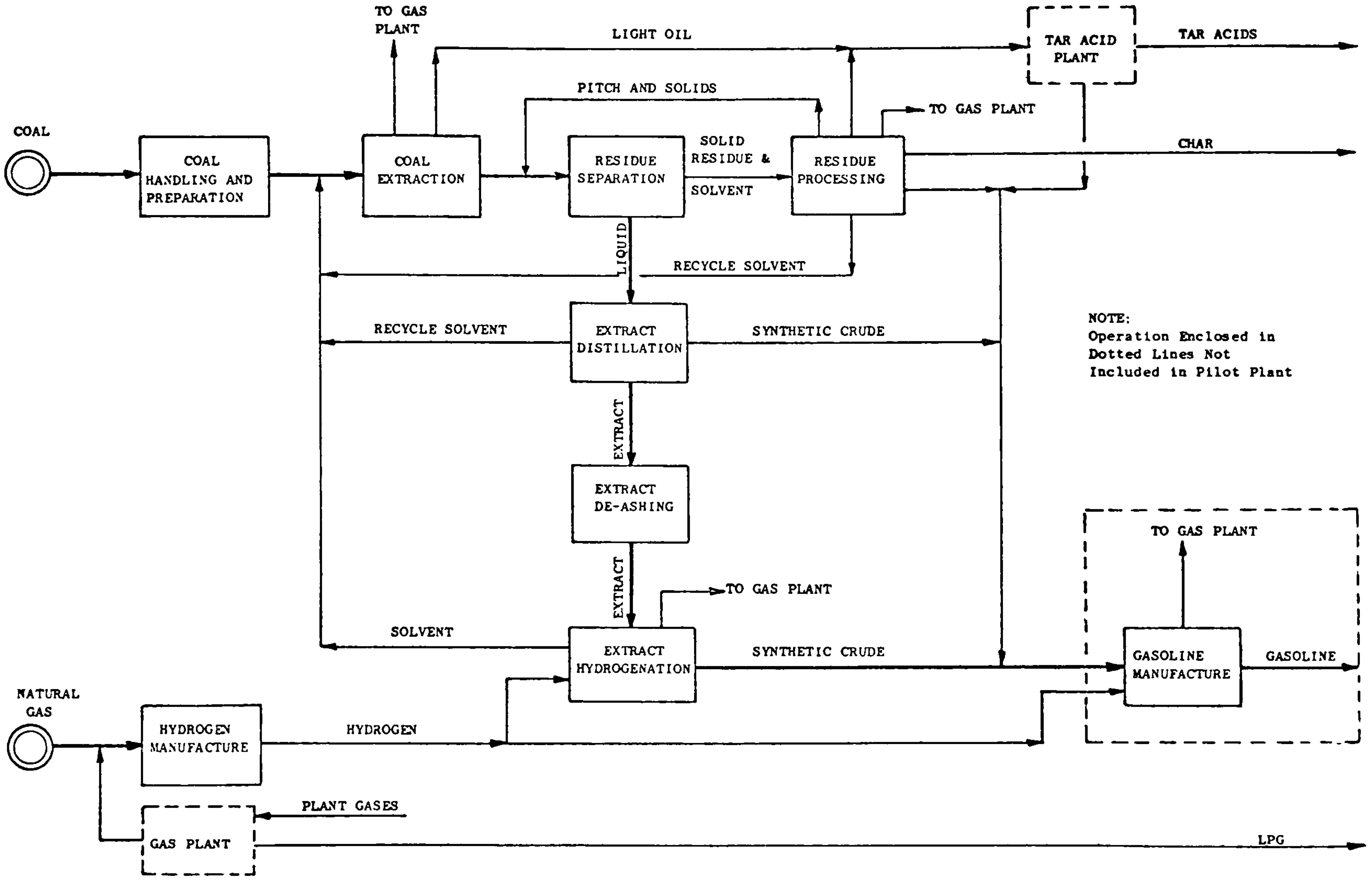
During that period Consol designed a pilot plant to process 20 tons of coal a day to produce about 60 bbl/d synthetic crude oil from highly caking Eastern bituminous coals. As prime contractor, Consol subcontracted the engineering of the pilot plant to C. W. Nofsinger Company and the construction of the plant at Cresap, W. Va. to Dravo Corporation. Nofsinger started on the engineering in June 1964. Dravo started construction in October 1965 and completed it in May 1967. Operation of the plant, by Consol, began with break-in during November 1966; the plant was operated until February 1970. It has been idle since then.

Consol prepared nine reports on the process and plant during the contract period which were issued by OCR. Other reports on the process and plant issued by OCR were prepared by Foster Wheeler Corp. (2 reports) Ralph M. Parsons, Inc., Schroeder Associates, Chem Systems, Inc., American Oil Company and Hydrocarbon Research, Inc. (3 reports). The latest Foster Wheeler report (1972) and the final Consol report (1973) are reviewed in this article.

The CSF Process

The Consol synthetic fuels process uses a hydrogen-rich donor "solvent" which is

SCHEMATIC FLOW DIAGRAM
CONSOL SYNTHETIC FUEL PROCESS



reacted with coal in a stirred pressure vessel at elevated temperature. Typical conditions are 720° to 765°F, 160 psig, solvent-to-coal ratio of 1.5:1 and a residence time of 30 minutes. About 70 percent (by weight) of the moisture-and ash-free coal is converted of which about 80 percent is coal extract, a pitch-like solid at room temperature. The extract and exhausted solvent carry all the mineral matter in the original coal.

The original intent in the pilot plant was to remove practically all the solids in a pressurized rotary precoat filter at elevated temperature. The filtrate is separated by distillation into recycle solvent, synthetic crude oil and extract streams. The extract is subjected to catalytic hydrogenation and separated by distillation into solvent and synthetic crude oil streams.

The solvent and recycle solvent are used to extract coal by donating some of their hydrogen content. The situation is analogous to using tetralin, $C_{10}H_{12}$, as the solvent and letting each molecule donate 4H to the coal resulting in the formation of naphthalene, $C_{10}H_8$. The naphthalene would then be reconverted to tetralin by hydrogenation.

The filter provided for the pilot plant gave many mechanical problems and was replaced by hydroclones or liquid cyclones. The hydroclones yielded an extract with more solids and a residue with higher liquid content than the filters. Both factors are disadvantageous but the hydroclones achieved continuous duty and the filter did not.

Other mechanical difficulties plagued the plant and while the extraction section and the extract hydrogenation sections were each operated independently, integrated operations were never achieved; however, the product solvent from the latter was recycled to the extraction section so simulated combined operations were achieved and the technical feasibility of the process thus demonstrated.

The Foster Wheeler Report

Foster Wheeler Corporation prepared a report issued by OCR as Research and Development Report No. 70, dated February 1972, entitled "Engineering Evaluation and Review of Consol Synthetic Fuel Process." The process evaluated and reviewed is one Foster Wheeler developed based on the Consol experiences. Two conceptual plants are considered, both feeding 20,000 tons per day of dried Pittsburgh seam coal. The principal product is a low-sulfur fuel oil for use in utility plants and the industrial energy market.

The difference in the two plants, or cases, is the system used to produce hydrogen which is required to upgrade the coal extract. One system utilizes the currently available Lurgi solids gasifier and the other a conceptual version of the BCR BI-GAS process. The latter can operate on the char as produced in the CSF process but the former requires that the feed be pelletized or briquetted. According to the report the Lurgi feed is prepared by combining coal with char which results in more feed than needed for the required hydrogen production.

The feed and products from the plant are given in Table 1. The same information from the extraction section is given in Table 2 and from the extract hydrogenation section in Table 3. The last two are based on hydrogen from a BI-GAS plant.

The cost of the plant erected but without contingency, contractor's fee or interest during construction is $230 million using the BI-GAS hydrogen process and $306 million with the Lurgi. The hydrogen manufacturing plant is the most expensive section in each case, $66 million and $101 million, respectively.

Basic economic factors used to compute the 20-year average selling price were:

Coal cost, 35¢/MM Btu
Interest on debt, 7%
Return on investment, 11%
Debt-equity ratio, 65/35
Depreciation, 5% (20 years)
Income tax, 54%

TABLE 1

Foster Wheeler Report
FEED & PRODUCTS

	CASE A: BI-GAS		CASE B: LURGI	
	Thousand Tons per day	Billion Btu per day	Thousand Tons per day	Billion Btu per day
Input				
As Rec'd Coal	23.36	-	29.24	-
MF coal	20.00	506	25.03	633
Output				
Net Gas	1.81	74.5	2.75	138.8
Naphtha	1.60	62.5	1.73	67.9
Fuel Oil	6.17	221.9	5.96	214.3
Ammonia	.13	-	.13	-
Sulfur	.83	-	1.09	-
Ash	2.49	-	3.16	-
	13.03	358.9	13.82	421.0

TABLE 2

Foster Wheeler Report
EXTRACTION INPUT, OUTPUT AND ANALYSES, CASE A, HYDROGEN BY BI-GAS

INPUT	M T/d	Wt.%
MF Coal	20.00	97.5
Hydrogen	.05	2.5
	20.05	100.0
OUTPUT		
L. Oil	.14	0.7
Extract	10.71	53.5
Residue	5.21	25.9
Ash	2.64	13.2
HC Gases	.26	1.3
Other	1.09	5.4
	20.05	100.0

Analysis of Product Streams

Wt.%	L.Oil	Extr.	Res.	HC Gas	Other
H	8.2	6.4	3.8	19.8	8.1
C	90.7	85.7	80.9	80.2	4.7
N	.1	1.5	1.9		
O	.1	4.6	5.8		62.1
S	.9	1.8	7.6		25.1
Ash		*	*		
	100.0	100.0	100.0	100.0	100.0

*Analyses reported on ash-free basis

TABLE 3

Foster Wheeler Report
EXTRACTION HYDROGENATION INPUT, OUTPUT AND ANALYSES, CASE A

INPUT	M T/d	Wt.%
Extract	10.42	90.6
Residue	.44	3.8
Hydrogen	.65	5.6
	11.51	100.0
OUTPUT		
L. Oil	1.51	13.1
HC Gas	1.06	9.2
Fuel Oil	5.78	50.2
Residue	2.17	18.8
Ash	.15	1.3
Other	.85	7.4
	11.52	100.0

Analysis of Product Streams

Wt.%	L.Oil	HC Gas	Fuel Oil	Res.	Other
H	14.5	21.3	11.0	6.8	10.9
C	85.3	78.7	88.0	90.4	
N	.1		.4	1.2	12.5
O			.3	.8	54.4
S			.3	.8	22.2
Ash			*	*	
	99.9	100.0	100.0	100.0	100.0

*Analyses reported on ash-free basis

The calculated selling price of fuels made is \$1.0222/MM Btu for Case A when hydrogen is made by BI-GAS and \$1.0940/MM Btu when hydrogen is made by the Lurgi process.

Comment

The Foster Wheeler report does not attempt to optimize any of the process variables. The price of low sulfur fuel oil resulting from the process is higher than what oil from petroleum was selling for in 1972 when the report was prepared. Since then the prices of coal, oil, labor, capital and equipment have all increased, but the products still do not appear to be competitive. How much the selling price could be reduced by optimization is speculative--but so is the price of low sulfur fuel oil five years from now when a commercial plant based on the Consol concept could be in operation.

The Consolidation Coal Report

The Consol Final Report was issued by OCR as Research and Development Report No. 39, Volume V in April 1973 titled "Development of CSF Coal Liquefaction Process."

Bench scale and pilot plant extraction of Pittsburgh seam coal were carried out in a continuous manner with consistent kinetic data, yield structure and operability. The former was at a coal feed rate of 0.12 T/d and the latter at 20 T/d. Continuous hydrogenation of the extract at both bench scale size and pilot plant size was accomplished. The former was done by Consol at a rate of 0.10 T/d and the latter was done by Hydrocarbon Research, Inc. at 3 T/d. The pilot plant unit at Cresap had a capacity of 13 T/d of extract feed but inconsistent results due to mechanical malfunctions rendered the data useless for correlating with the other two modes.

The use of zinc chloride as a hydrocracking catalyst was partially developed by bench scale work but abandoned in 1967 for lack of funds. This American concept offers the possibility of significant reductions in the cost of manufacturing distillate fuels, especially from Western coals.

The economics of a fuel oil plant based on eastern deep coal were, at best, marginally competitive with petroleum products when the plant capacity was 40,000 to 60,000 bbl/d. It was shown to be competitive only by taking advantage of scale, with capacity increased to 250,000 bbl/d, and by using low-cost Western coal. By an appraisal made in 1972 the CSF process for making 0.2%S fuel oil was comparable in cost with other processes for making a similar product from coal. However, it could not compete pricewise with 0.3%S imported fuel oil.

The report urges that the Cresap Pilot Plant, as the only existing large-scale pilot plant owned by OCR with the capability of evaluating the production of low-sulfur fuel oil from Eastern caking coals, be reactivated and renovated as soon as possible so this problem can be investigated.

# # # #

RESULTS OF COED OIL FILTRATION TESTS REPORTED

The results of filtration tests conducted by FMC Corporation on oil produced by the COED process were discussed in a paper presented by Shoemann, Ford & Jones of FMC at the Fourth Joint Chemical Engineering Conference held in Vancouver, B.C., September 12, 1973. The paper entitled "Pressurized Rotary-Drum Precoat Filtration of COED Oil From Coal", describes the operation of the COED pilot plant filter in filtering over 3,000 barrels of oil produced from three types of coal.

Description of Filter System

The pilot plant filter system (shown in Figure 1) includes an oil feed system, a system for precoating the filter drum, the filter, filtrate collection tanks and a heat pressurizing nitrogen supply to provide the filtration driving force.

The pilot plant filter is a drum two feet in diameter and 13 inches wide with approximately six square feet of filter area. The drum is enclosed in a pressure vessel containing a doctor blade for cutting off the collected solids. Electrical strip heaters are attached to the exterior shell to maintain the filter operating temperature. Adjustable speed drives provide power for drum rotation and doctor blade advancement. The

TABLE 1*

FILTRATION OF COED OILS FROM COAL

	Coal Type		
	Colo. Bear	Wyo. Big Horn	Ill. No. 6
Period of operation (weeks)	30	5	44
Oil filtered (bbls.)	1290	90	1800
Viscosity of oil (cps)			
200°F	120	19	140
350°F	5.0	3.6	7.5
Solids in feed (%)	6-17	9-11	3-9.5
Solids in filtrate (%)	0.01-0.09	0.03-0.04	0.01-0.09
Highest filtration rate (gal/hr/ft^2)	9.5	4.1	9.4
Most consecutive precoats	14	3	17

*Compiled from Schoemann's paper

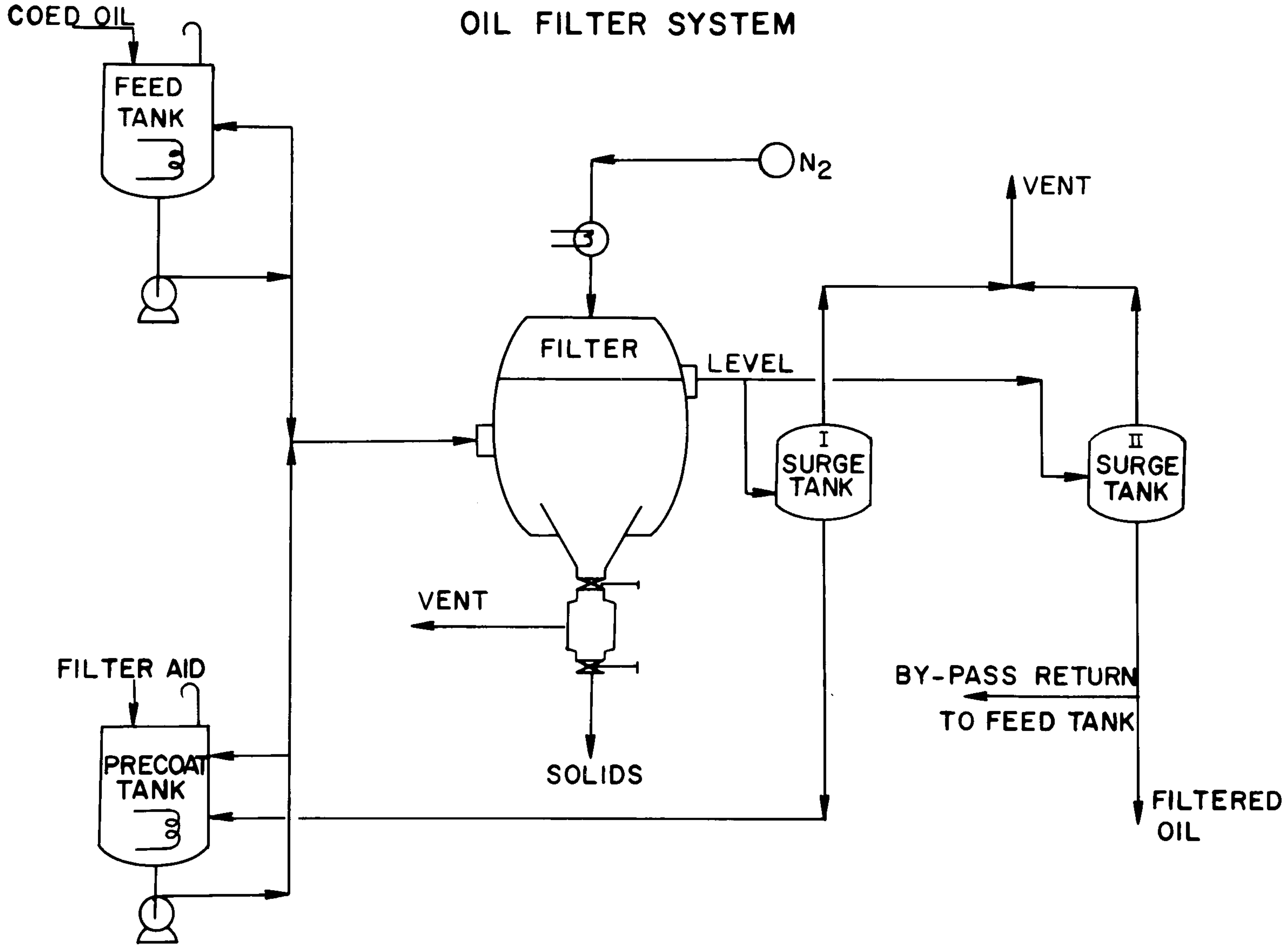
TABLE 2*

FILTRATION VARIABLES INVESTIGATED

VARIABLE	RANGE-OR VALUE
Filter Aid	Six Grades
Drum Speed	0.5-2.0 rev/min.
Doctor Blade Advance	0.0-2.0 mil/min. (0.0-4.0 mil/rev.)
Pressure Differential	12.0-28.0 psi
Slurry Feed Solids	2.5-15.0 Wt.%

FIG. I

OIL FILTER SYSTEM



doctored solids are collected in a solids receiver for periodic removal from the pressurized zone.

Filter Preparation And Operation

During an initial filter start-up, the unit is heated to process temperatures through the use of the electrical strip heaters and flow of hot nitrogen. The drum is rotated at 2 rev./min. A chopped asbestos/filter aid mixture (Johns-Mansville Fibra-Flo) is added to the agitated precoat oil (previously filtered oil). The precoat oil is circulated thru the filter with oil flow regulated by level control. This provides about a 1/16-inch base coat layer on the filter surface. This layer prevents filter aid penetration and blinding of the filter wire cloth.

Next, filter aid is added to the precoat oil in five-pound batches approximately 15 minutes apart to maintain a constant concentration of about one percent. A total of approximately 20 lbs. of filter aid is used for a precoat. Precoat oil temperature is controlled through cooling water and steam coils in the precoat oil tank. The differential pressure is adjusted upward during precoating so that at the completion of precoating it equals the filtration differential pressure set point. This is controlled by pressurizing the nitrogen pressure controller at values typically between 15 and 25 psi. The completed precoat is 1 to 1-1/4 inches thick. Before termination of precoating, the doctor blade is advanced to smooth the precoat and provide a uniform surface. The doctor blade advance rate is set at the desired speed and is advanced during the change from precoat oil to unfiltered COED oil circulation.

For filtration, the drum rotation is reduced from 2 rpm to 0.5-1.5 rpm. Following a sufficient interval, filtered oil is sampled at the bottom of the filtrate receiver and tested for solids content (defined as quinoline insoluble material). If the test is satisfactory (less than 0.1 percent solids), filtered oil is valved to the filtered oil storage tank; if not satisfactory, filtered oil is recycled until the solids content is less than 0.1 percent. Filtration of COED oil is continued until the doctor blade reaches a limit switch which stops the blade approximately 1/4-inch from the drum surface. COED oil feed is then stopped and preparations made for adding a new percoat on the existing basecoat.

Test Results

Since the removal of solids from coal streams has been a major obstacle to successful coal liquefaction by previous investigators, the results reported here are significant. However, it should be noted that most of the previous work on filtration of this type was performed on hydrogenation products and this work was on carbonization products. The recent attempts at the OCR plant at Cresap, W. Va. were discouraging with filtration finally abandoned in favor of hydroclones.

COED oils produced from three different types of coal were filtered and a summary of the physical characteristics and tests results for each are given in Table 1. Table 2 lists the filtration variables that were investigated. Oil containing solids concentrations of 5.0 to 10.0 weight percent were filtered to less than 0.1 percent at rates of 7 to 9 gal/hr/sq. ft. Consecutive precoats up to a maximum of 17 for a run on Illinois No. 6 coal were obtained.

Comments

Apparently, FMC has successfully demonstrated that oil produced by the COED process could be filtered on a pilot plant scale and should be adaptable to scale up to a commercial operation. The removal of solids from oil produced by a liquefaction process to small concentrations will allow such oil to be burned in turbines or will simplify catalytic hydrogenation to refined products, thus greatly increasing its market value.

Future Filter Program

The filter will be operated for the duration of the COED pilot program. Future studies will include increasing the filtration temperature to the 375°-400°F range and the use of hydrotreated product oil/COED pyrolysis oil blends. Both approaches are aimed at increasing filtration rates by reducing the viscosity of the oil to be filtered.

# # # #

NPC COAL TASK GROUP REPORT AVAILABLE

The Coal Task Group of the Other Energy Resources Subcommittee of the National Petroleum Council's Committee on U. S. Energy Outlook has now released its report, "U.S. Energy Outlook, Coal Availability." Previously, the full report of the NPC subcommittee was reviewed in the March 1973 issue of this report on page 1-1. Also, the report of the oil shale task group was reviewed in the September issue on page 2-10.

The coal task group report is available at a cost of $18 from:

Director of Information
National Petroleum Council
1625 K Street, N.W.
Washington, D. C. 20006

Five topics are discussed in the report: (1) demand for coal, (2) coal resources (3) coal mining, (4) future coal supply outlook, and (5) potential future coal utilization.

Coal Demand

The task group has made estimates of coal demand by market sector for the years 1975, 1980 and 1985. These estimates are presented in Table 1 from the report and the figures were projected for conventional uses only; requirements for synthetics production were not included.

These domestic demand figures were derived on the basis of a growth rate of 3.5 percent. Electric utilities are expected to continue to be the largest user of coal for conventional uses through 1985 as shown in Table 1.

Coal Resources

The report states that there are some 150 billion tons of recoverable coal of which 105 billion are located underground and 45 billion near the surface. These have been firmly defined in formations of comparable thickness and depth to those being mined under current technological conditions.

These 150 billion tons represent less than 5 percent of the 3.21 trillion tons of total coal resources which are estimated by the U.S. Geological Survey. Thus it is concluded that the coal resources are quite adequate even at maximum production growth rates. Less than 10 percent of the recoverable resources are expected to be mined by 1985.

Coal Mining

The task group states that the future ability of the coal industry to supply its overall share of U.S. energy demand will depend on its continued ability to produce coal from deep mines in an efficient and economic manner.

This conclusion is reached in spite of the fact that surface mining requires less investment and operating costs and is also not subject to the health and safety problems associated with deep mining. However, it is subject to increasingly stringent environmental requirements.

Future Coal Supply Outlook

Future coal supply was estimated for three cases: Case 1 represents a 5 percent rate of growth for domestic uses and an overall growth rate of 6.7 percent when exports and synthetic markets are included; Case II/III represents a moderate growth rate of 4.5 percent overall; and Case IV represents a minimum growth rate of 3.0 percent for conventional domestic markets and an overall growth rate of 3.6 percent when exports and synthetic fuels markets are included.

The three cases of estimated development are tabulated in Table 2 from the report.

The task group defined the following determining factors which will affect the future supply and consumption of coal.

- Developments in improved mining technology must be substantially accelerated to offset the severe impact of the Coal Mine Health and Safety Act of 1969 on production capacity.

- A program for rapid development of manpower, both mine workers and mining engineers, must be vigorously pursued.

TABLE 1*

COAL DEMAND BY MARKET SECTOR
(Millions of Tons per Year)

	1970	1975	1980	1985
Blast Furnaces	86	102	110	116
Foundries and Miscellaneous	10	10	10	10
Total Coking Coal	96	112	120	126
Residential/Commercial	10	7	5	3
Industrial	91	87	84	80
Electric Utilities	322	415	525	654
Total Domestic U.S.	519	621	734	863
Coking Coal Export	56	76	94	120
Electric Utility Export	15	16	17	18
Total Export	71	92	111	138
Total	590	713	845	1,001

*From Table 5, p. 13 of NPC Coal Task Group Report, "Coal Availability"

TABLE 2*

TOTAL FUTURE COAL SUPPLY-CONVENTIONAL MARKET,
EXPORTS AND SYNTHETIC FUELS

	Millions of Tons				Annual Growth Rate (Percent)
	1970*	1975	1980	1985	
	Case I				
Conventional Markets	519	662	852	1,093	5.0
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	48	232	-
Liquids	0	0	12	107	-
Total	590	754	1,023	1,570	6.7
	Cases II/III				
Conventional Markets	519	621	734	863	3.5
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	31	121	-
Liquids	0	0	-	12	-
Total	590	713	876	1,134	4.5
	Case IV				
Conventional Markets	519	603	704	819	3.0
Export	71	92	111	138	4.5
Synthetic Fuels					
Gas	0	0	15	47	-
Liquids	0	0	0	0	-
Total	590	695	830	1,004	3.6

*From Table 1, p. 8 of NPC Coal Task Group Report, "Coal Availability"

- To guarantee the transport of increasing tonnages, the pool of railroad hopper cars as well as the efficiency of car utilization must be increased, and certain locks must be improved in the river system to prevent major bottlenecks. To keep U.S. export coals competitive, better ways must be found to accommodate the new larger sized coal carrying ships at our ports, notably Hampton Roads, Virginia.

- Technology must be developed to permit use of high-sulfur coal in power generation without polluting the air. Alternate processes should be pursued to fit the widely varying needs of existing plants, new and old, large and small. Desulfurizing by liquefaction and by gasification, as well as by stack gas cleanup, may all be required during the next 15 years. The present substantial research programs in these areas should be further expanded.

Potential Future Coal Utilization

The task group defines three uses for which coal production will have to be expanded through the period from the present thru 1985. These three uses are: (1) coal for power generation, (2) coal for synthetic pipeline gas, and (3) coal for synthetic liquid fuels.

Future use of coal for power generation will heavily depend upon satisfactory resolution of air pollution problems. For the near term period this means development of satisfactory stack gas cleanup systems, the use of low-sulfur fuels (including low-sulfur fuels produced from coal), or the development of combined-cycle power plants.

The Coal Task Group, in analyzing the future potential of coal-based synthetic pipeline gas, concluded that neither technological considerations nor the adequacy of supply of feedstocks would be major factors affecting the growth of synthetic gas production. The buildup rate would, in fact, be primarily influenced by economic or other considerations.

The task group pointed out that the Lurgi process is available today and that other processes currently in the pilot plant stage will become available during the middle part of the period to 1985.

The task group developed a range of prospective buildup rates of synthetic gas production. Three cases were developed and defined as follows:

1. Case I: A maximum rate of buildup under special conditions and appropriate special policies.

2. Case II/III: A rapid but practical buildup.

3. Case IV: Minimum rate of growth.

Table 3 reproduced from the report illustrates the three cases of growth in synthetic gas production.

TABLE 3*

Installed Capacity of Synthetic Gas From Coal (TCF per year - 90-percent Operating Factor)

Year	Case I	Case II/III	Case IV
1976	0.08	0.08	-
1977	0.16	0.12	-
1978	0.28	0.16	-
1979	0.40	0.24	-
1980	0.56	0.36	0.18
1981	0.80	0.52	-
1982	1.12	0.68	-
1983	1.52	0.84	-
1984	2.00	1.08	-
1985	2.48	1.31	0.54

*From Table 33, p. 67 of NPC Coal Task Group Report, "Coal Availability"

The expected cost of such gas was estimated at $.90-$1.10/MMbtu by the task group in its initial appraisal. However, since that time estimates of required investment and operating costs has significantly increased so that the estimates of gas cost will have to be revised upward.

Coal For Synthetic Liquid Fuels

The task group first points out that no acceptable technology for liquefaction has yet been proved. Therefore, the buildup rate for a coal liquefaction industry is necessarily dependent upon the rate at which technology is developed.

Nevertheless, the task group did give its estimates as to the buildup rate of a coal liquefaction industry. As with the coal gasification estimates, Case I assumes maximum incentive; Case II/III assumes a moderate buildup; and Case IV assumes no incentive (i.e. no commercial liquefaction industry by 1985).

The task group's estimate as to the buildup of a synthetic liquids industry are presented in Table 4.

TABLE 4*

Buildup of Synthetic Liquids From Coal (MB/D)

Year	Case I	Case II/III	Case IV
1977	30	-	-
1978	30	-	-
1979	30	-	-
1980	80	-	-
1981	130	30	-
1982	180	30	-
1983	280	30	-
1984	480	30	-
1985	680	80	-

*From Table 39, p. 73 of NPC Coal Task Group Report, "Coal Availability"

The task group estimated the cost of producing synthetic crude oil from coal in the range of $6.25 to $7.50/Bbl depending upon the coal source.

Capital Requirement

As an indication of the enormous magnitude of capital needed to finance such a synthetic fuels industry Table 5 is presented as taken from the report.

For Case I conditions it is estimated that $14 billion will be needed to finance synthetic gas and liquid plants and associated mines through the year 1985. Even under the more conservative conditions represented by Case II/III some $5.4 billion will be required.

TABLE 5*

CUMULATIVE CAPITAL REQUIREMENTS FOR COAL-BASED SYNTHETIC GAS AND LIQUID PLANTS (Millions of Dollars)

	1970	1975	1980	1985
	Case I			
Synthetic Gas Plants1/	-	-	1,700	7,500
Synthetic Liquid Plants2/	-	-	590	4,500
Associated Mine Investment3/	-	-	387	2,030
Total	-	-	2,677	14,030
	Cases II/III			
Synthetic Gas Plants	-	-	1,100	4,000
Synthetic Liquid Plants	-	-	-	590
Associated Mine Investment	-	-	187	780
Total	-	-	1,287	5,370
	Case IV			
Synthetic Gas Plants	-	-	550	1,650
Synthetic Liquid Plants	-	-	-	-
Associated Mine Investment	-	-	108	280
Total	-	-	658	1,930

1/ Basis: $250 million per standard-size plant
2/ Basis: $7,400 per B/D first 80,000 B/D; $6,500 per B/D above initial 80,000 B/d
3/ Basis: $6.00 per annual ton of surface mine capacity
*From Table 42, p. 75 of NPC Coal Task Group Report, "Coal Availability"

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MINIMIZING ENVIRONMENTAL DAMAGE IN STRIP MINING DISCUSSED

The Bureau of Mines recently issued a preliminary report dealing with strip-mining techniques that will minimize environmental damage. Preliminary Report 192, dated August 1973, is tailored specifically to the upper Missouri River area in Wyoming, Montana, and North and South Dakota. The title of the report is "Strip Mining Techniques to Minimize Environmental Damage in the Upper Missouri River Basin States."

Author Franklin H. Persse reviews the geologic setting of the Missouri Basin coal, then summarizes the current land use, temperature and precipitation data, and air and water quality considerations. He discusses environmental considerations to be considered in the planning of mining, water control, transmission lines and refuse disposal.

With a variety of mining situations and with new regulations on mining and reclamation going into effect, Persse sees many opportunities to develop new mining techniques. He discusses overburden removal with draglines which is currently the most popular method. With the separate removal of topsoil now required, however, he also discusses the possibility of using other equipment, either alone or in combination. For example, he suggests using a bucket-wheel excavator and shovel working in tandem for overburden removal. The shovel would remove most of the overburden and the wheel would remove the top portion including the topsoil, overreaching the shovel on both sides of the pit and thereby casting topsoil on top of the overburden deposited by the shovel. Several other combinations are also suggested.

The author's summary and conclusions are as follow:

"A fixed cost cannot be estimated for protecting the environment in any area or region because of the many variables in mining and the differences of opinion as to what costs should be charged to environmental protection. Such costs, regardless of the distribution and accounting method, must be considered a part of the total cost of producing coal or lignite, and must be paid by the consumer. Therefore, to be competitive, the mine operator must protect the environment in the best possible way for the least possible expenditure. Mining must be done by methods that cause minimal damage so that necessary repair is minimal. Mined-land reclamation must be done both to satisfy mandatory requirements and to obtain public acceptance. Such operations will be difficult and costly in the beginning but should pay out as a long-term investment. Correctly charging such costs also will be difficult.

"Usual accounting procedure is that everything done to protect the environment be so charged, but interpretations can be misleading. Many actions taken to protect the environment can reduce costs elsewhere. Curtailing dust will extend machinery life. Diverting and settling water to prevent pollution can prevent flood damage and improve working conditions. Reclaiming the mined-land suppresses dust, reduces the potential of erosion, improves the appearance of the mine, and retains mined land on the tax roll for future use. All are beneficial to the miner, his machinery, and the public. Thus, accounting charges should be equitably apportioned on the basis of judgment and benefits.

"The semiarid climate of the Upper Missouri River basin necessitates suppression of dust for the well-being of both men and machinery. With a few exceptions, no changes in the methods used to suppress dust were required by the enactment of air pollution control laws. Additional curtailment of airborne particulate may be required at working places for compliance with the Federal Coal Mine Health and Safety regulations. Dust generated from the coal or lignite should constitute little if any problem because of the high moisture content, but the dry overburden may cause limits to be exceeded. Mine employees currently are wearing detectors to determine if they are exposed to excessive amounts; that is, more than 2 milligrams of particles 5 microns or less in size per cubic meter of air.

"In the Upper Missouri River basin, preventing water pollution at coal and lignite operations generally would include diverting surface water from the working area by some means that would not increase sedimentation

FIGURE 1

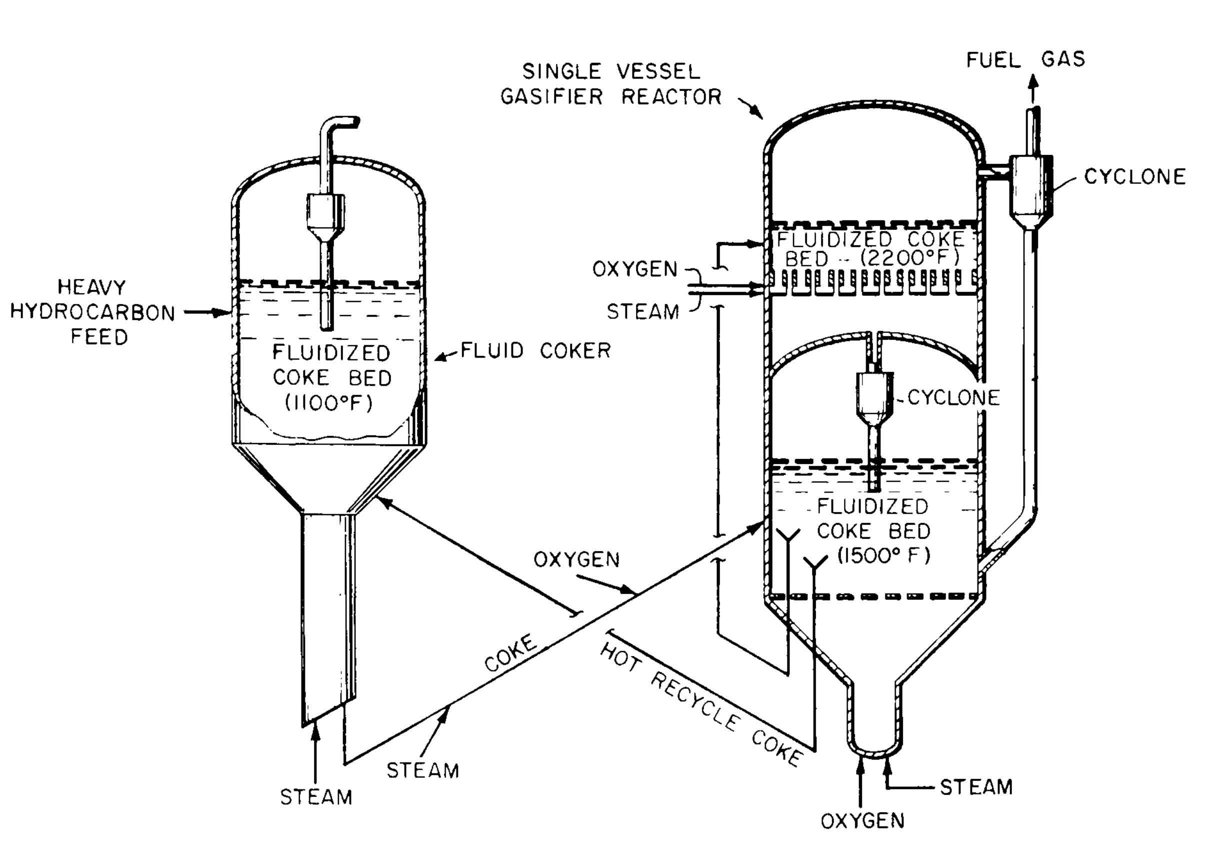
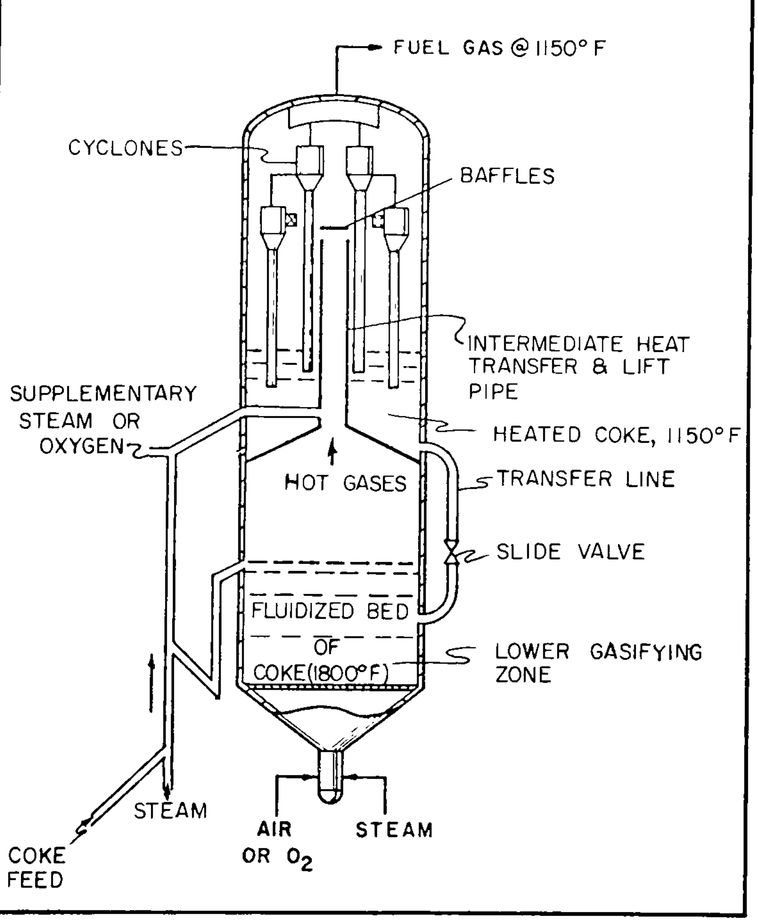


FIGURE 2



or dissolved salts, testing all discharge water for purity, measuring all water entering and leaving the mine area, and constructing a settling basin for mine water and other water containing sediments that is to flow into a watercourse. No acid water would flow from the mining area, but dissolved salts could be excessive. Should such a condition occur, some method of preventing salt contamination or partial removal of the salt to reduce its concentration would be necessary. Should washing the coal or lignite at a preparation plant be required, which seldom would happen in this region, a closed system is recommended. Costs will vary considerably for each operation, and how much is chargeable to environmental protection is optional. By comparison, however, water pollution prevention would not be as costly as it would be in areas where treatment of acid water is required.

"Reclamation of the strip-mined land in the Upper Missouri River basin will require a greater annual expenditure than that for preventing pollution of air or water. The reclamation cost per million Btu of energy recovered from the thick deposits (25 feet or more) will be less than in other regions of the Nation; however, incorporating land reclamation with removal of overburden so that material with the greatest potential for establishing plant life becomes the surface of the reclaimed spoil may increase the total production cost 1 or 2 mills per million Btu. Such reclamation techniques can be beneficial in other ways, however, making possible faster release of bonds, quicker restoration of the mined land for other uses, and improved aesthetic values. Similar benefits also may be realized by mulching, fertilizing, and irrigating.

"Strip mining is a one-time productive use of the land. Reclamation readies such land for other productive uses, and the responsibility is implicit to see that productive use continues just as it would if the land were never mined."

# # # #

ESSO PATENTS TWO REACTOR DESIGNS FOR USE AS COKE GASIFIERS

Esso Research and Engineering Company recently obtained U.S. Patents 3,752,658 and 3,759,676 for the design of two reactors suitable for gasifying excess coke from conventional fluid cokers. The gas produced would be fuel gas, a mixture of H_2 and CO.

Each of these reactors is said to be easy to operate, each has a minimum of transfer lines, and, in each, the design prevents oxygen from being accidentally admitted into zones where explosions could occur.

U. S. Patent 3,752,658

Fuel gas is produced from coke by a two-stage, single-vessel process wherein cold coke is injected into a low-temperature zone where it reacts with oxygen. The resultant gases, along with steam, are contacted in a high-temperature zone with hot coke to produce fuel gas.

Figure 1 depicts the process, illustrating how the single vessel gasifier reactor operates in conjunction with a conventional fluid coker.

U. S. Patent 3,759,676

In this single-vessel coke gasifier reactor, coke to be gasified is fluidized with steam and is injected into an intermediate heat transfer zone, which is a lift pipe. The cold coke is heated by the hot gases emanating from a lower gasifying zone, the coke being heated to about 1050°F. The hot gases cool to about 1050°F.

Coke and lift gas are separated in an upper disengaging zone. Preheated coke is then fed into the lower gasifying zone at a rate easily controlled by a slide valve in a transfer line.

The lower gasifying zone is a fluidized bed of hot coke particles suspended in oxygen and steam. The temperature of the bed is controlled at 1800°F by varying the amounts of combustion oxygen admitted (which supports the exothermic reaction $C + O_2 \rightleftharpoons CO_2 + 94,052$ calories) or the amount of steam admitted (which supports the endothermic reaction ($C + H_2O \rightleftharpoons H_2 + CO - 31,382$ calories).

Figure 2 depicts the design of this gasifier vessel.

# # # #

CONSOL PATENTS VARIATION OF SOLVENT EXTRACTION PROCESS

Consolidation Coal Co. has been assigned U.S. Patent 3,748,254, "Conversion of Coal by Solvent Extraction", which discloses a method of utilizing the reject stream of hydrocarbonaceous material produced by solvent extraction processes.

In the described process coal is partially converted by solvent extraction to a mixture of extract, solvent and undissolved carbonaceous residue. The mixture is separated into a low solids-containing fraction and a high solids-containing fraction. The composition of the latter is adjusted so that its admixture of solids, extract and solvent is such as to make it pellitizable. Pellets are formed from the pellitizable composition, preferrably in a rotary drum kiln, then hardened in an induration zone by means of water sprays. The indurated pellets may then serve either as solid fuel or as a source of carbon in carbon-steam reactions.

# # # #

PATENTED MODIFICATION TO BCR PROCESS ALLOWS PRODUCTION OF LOW-SULFUR CHAR PRODUCT

U.S. Patent 3,746,522, assigned to the U.S.A. describes a modification to the Bituminous Coal Research, Inc. coal gasification process which allows production of low-sulfur char product.

The usual flowsheet for the BCR coal gasification process shows that all char is recycled to extinction, being burned in the process to provide process heat. Patent 3,746,522 discloses that a portion of the char product may be diverted to a fluidized bed reactor where treatment with hydrogen-bearing recycle gas accomplishes desulfurization of the divered portion of char.

Diversion of a portion of the char has an additional advantage in that it permits an increase in the raw coal charge to the BCR gasification process, which, in turn, results in an overall increase in methane production.

Figure 1 is a drawing which shows how the reactor, in which a fluidized bed of (diverted) char is desulfurized, fits into the overall BCR scheme of coal gasification.

# # # #

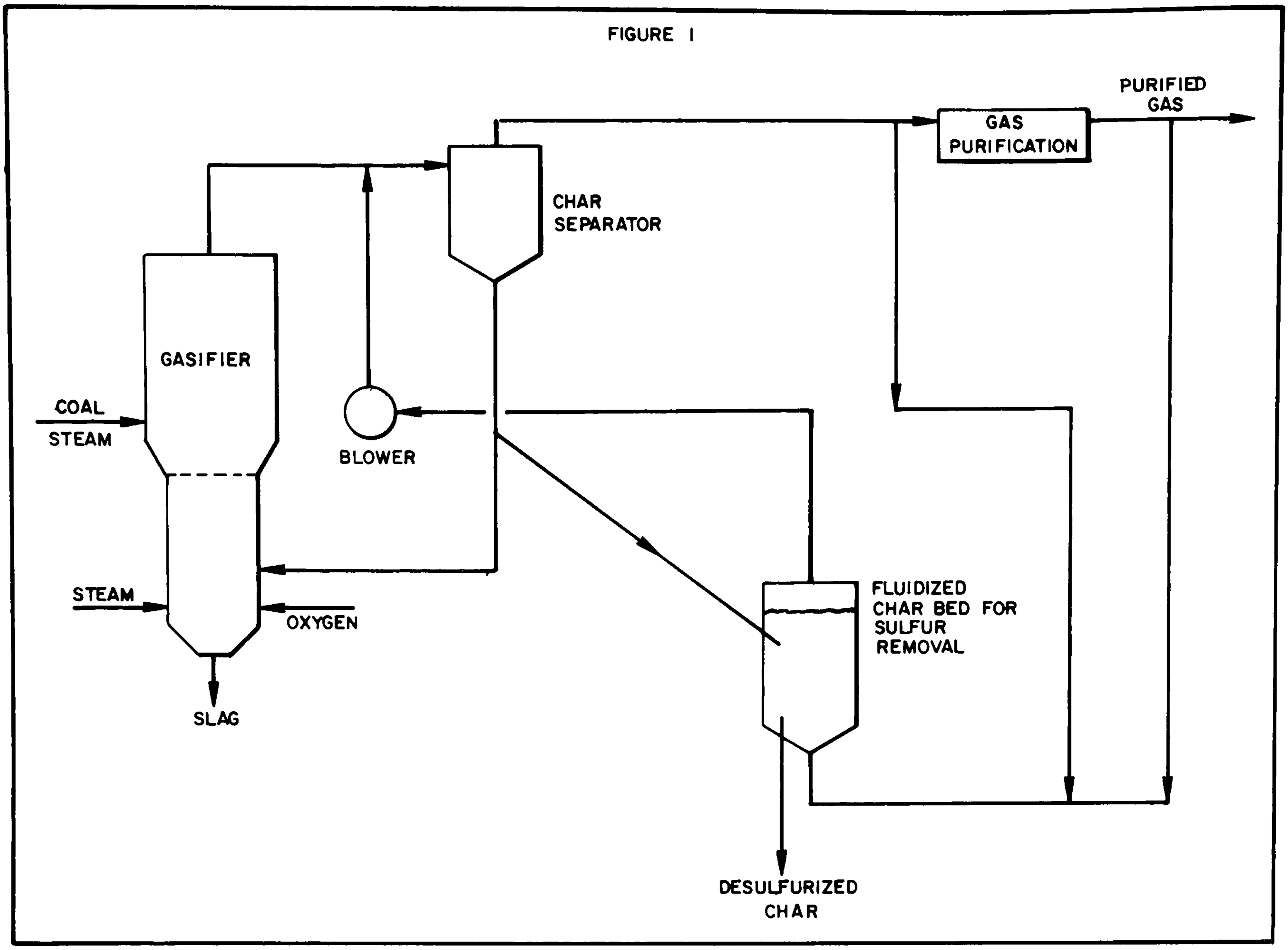


FIGURE I
PURIFIED GAS
GAS PURIFICATION
CHAR SEPARATOR
GASIFIER
COAL
STEAM
BLOWER
STEAM
OXYGEN
SLAG
FLUIDIZED CHAR BED FOR SULFUR REMOVAL
DESULFURIZED CHAR

SENATE APPROVES TOUGH RECLAMATION ACT

The U.S. Senate overwhelmingly approved (82 to 8) a tough coal surface mining reclamation act on October 9 which includes an amendment by Sen. Mansfield banning strip mining on millions of acres of homesteaded land on which the federal government owns the mineral rights. The bill (S.425) provides minimum federal standards for mined-land reclamation which require restoration to the approximate original contour and vegetation.

Action in the House on a reclamation bill has been postponed until at least the end of January. On November 12, however, a House Interior Subcommittee approved H.R.11500 which is quite similar to S.425 with the exception that it stringently and specifically outlines minimum performance standards. Another difference is that H.R. 11500 does not contain an equivalent of the Mansfield Amendment. A detailed review of each bill follows.

S.425, Surface Mining Reclamation Act of 1973

The bill was introduced January 18, 1973 by Senator Jackson and sponsored by Senators Buckley, Mansfield, Metcalf and Moss. Strip mining of coal on lands that can't be reclaimed according to the terms of the act and in national parks, refuges, scenic areas and wild rivers is prohibited. Within six months after enactment of the law the Secretary of Interior will be responsible for formulating regulations covering surface mining and reclamation operations for coal. The regulations will set forth the requirements a state must meet in developing a state program to meet the requirements of the act.

Under provisions of the act, an Office of Surface Mining Reclamation and Enforcement would be established within the Department of Interior. The office would be headed by a director appointed by the President and would be responsible for establishing, administering and monitoring various state and federal programs relating to surface mining and reclamation.

State Authority and Programs

Within 12 months after promulgation of the federal regulations the states must establish programs which provide for the effective implementation, maintenance, and enforcement of a permit system for regulation of surface mining and reclamation operations for any coal lands within the state. Following review by the Secretary of Interior and various federal agencies and public review, the Secretary of Interior shall, within four months following submission of the state programs, approve the state program if it meets <u>or exceeds</u> the requirements of the act. If disapproved, a sixty-day extension period is provided for submission.

If a state fails to implement a state program within the allotted time, the Secretary of Interior will have exclusive jurisdiction for the regulation and control of strip mining and reclamation within that state. Provision is made for implementation of a state program at some later date, if and when the state program meets the requirements of the Act.

For the 22-month period (plus any extensions) after the Act has been enacted and before states are required to implement their own programs, an interim permit system for new or expanded (15+%) surface mining operation will be in effect, and states may issue interim permits in accordance with the provisions of this act.

Minimum Requirements

Although the act does not specifically outline every requirement which will be placed on strip mining operations, it does establish minimum requirements. Some of the more important requirements follow:

. land must be returned to a condition at least capable of supporting uses they were capable of supporting prior to mining.

. approximate original contour must be established.

. all highwalls, terraces, spoils and mined surface areas must be stablized and protected from erosion.

. topsoil must be segregated and used to cover spoils.

. quality of surface and ground water must be maintained.

Land Areas Unsuitable For Surface Mining

An area may be designated unsuitable for all or certain types of surface mining operations if:

. reclamation pursuant to the requirements of the Act is not physically or economically possible.

. surface mining operations or other major uses in a particular area would be incompatible with Federal, State, or local plans to achieve essential governmental objectives.

. the area is an area of critical environmental concern.

Mansfield Amendment

On October 8 the Senate approved by a 53 to 33 margin an amendment offered by Majority Leader Mike Mansfield which prohibits surface mining of coal on all lands where the surface is privately owned and the coal is federally owned. The amendment would have an enormous impact on western coal development. Secretary of the Interior Morton has urged the House Interior Committee to drop the amendment stating that "large coal deposits will be permanently lost from national fuel supplies because thick deposits close to the surface can only be mined by surface methods."

"In the eight states where coal is leased by the Federal government," Morton added, "over 42 million acres of land would be withdrawn from surface mining, representing about 38 percent of all land where federally owned coal is found." Table 1 shows the impact the amendment would have on existing federal leases in the Rocky Mountain and Northern Great Plains region, according to the U.S. Geological Survey.

Bill Has Other Controversial Provisions

The provision requiring restoration to "the approximate original contour of the land with all highwalls, spoil piles and depressions eliminated" has also come under attack. Carl Bagge, president of the National Coal Association, says the provision would effectively prohibit mining hillsides steeper than 20 degrees. According to the Council on Environmental Quality, the provision would prevent the surface mining of 1.9 billion tons of coal in Appalachia. The impact in the West would be minimal.

Another provision states that an area can be designated unsuitable for all or certain types of surface mining operations if it is an area of "critical environmental concern." This definition, which was taken from the Land Use and Planning bill passed by the Senate in June, is so broad that it could include just about any type of land. A member of the Senate Interior and Insular Affairs Committee concedes, "a state could prohibit all or some forms of surface mining entirely."

H.R. 11500, Surface Mining Act

The basic provisions of this bill are similar to S.425 with the exception that it stringently and specifically outlines minimum performance standards. A few of these are listed following to serve as examples:

1. Surface mining operations are to be conducted so as to maximize the utilization and conservation of the solid fuel resource being recovered so that reaffecting the land in the future through mining can be minimized.

2. Reclamation operations are to be kept current so that any one mined area will be reclaimed within 6 months after being mined.

3. Topsoil not replaced within 10 days must be covered by quick growing plants or other means to prevent erosion.

4. Responsibility of the operator for successful revegetation will be a period of 5 full years after the last year of augmented seeding, fertilizing, irrigation or other work to assure permanent vegetative cover suitable to the area, except in those areas or regions where

TABLE 1

EFFECT OF "MANSFIELD AMENDMENT" TO S.425 ON FEDERAL COAL LEASES IN ROCKY MOUNTAINS & NORTHERN GREAT PLAINS

State	Leased Acres	Private Surface Ownership Acres	Surface Minable Coal Reserves-MM Tons: Under Federal Lease	Under Private Ownership	Private Ownership as % of Federal Leases
Colorado	122,078	54,606	236	106	45
Montana	36,232	34,967	1120	1086	97
New Mexico	40,958	26,198	381	180	64
North Dakota	16,436	16,436	285	285	100
Utah	266,609	13,335	200	10	5
Wyoming	199,933	117,196	7801	4603	59
Total	682,246	262,738	9923	6270	63

Source: U.S. Geological Survey

the annual average rainfall is 26 inches or less, then the operator's responsibility and liability will extend for a period of 10 full years after the last year of augmented seeding, fertilizing, irrigation or other work.

The following performance standards are applicable to contour surface mining:

1. No mining operation will be permitted on slopes greater than 20 degrees from the horizontal unless the operator can affirmatively demonstrate that the mining operation and reclamation activities will not result in: (1) the permanent placement of overburden or other waste materials on the natural or other slopes above, or below the excavation; (2) slides and excessive erosion; (3) impoundments, either temporary or permanent, of water except for the intermittent retention of water for flood or sediment control purposes; and (4) the permanent exposure of the high wall.

2. Complete backfilling with spoil material shall be required to a contour necessary to completely cover the high wall and return the site to the approximate original contour, which material will maintain stability following mining and reclamation. High walls are not to be reduced by disturbing more land above the mine site.

3. Construct access roads, haulroads, or haulageways with appropriate limits applied to grade, width, surface materials, spacing, and size of culverts in order to control drainage and prevent erosion outside permit area, and upon the completion of mining either reclaim such roads by regrading and revegetation or assure their maintenance so as to prevent erosion and siltation of streams and adjacent lands.

4. No permit for a mining operation shall be issued for a period of time in excess of one year. Such permit may be renewed by the regulatory authority, providing mining operations were conducted in accordance with provisions of this Act. The regulatory authority may impose such additional requirements as he determines to be necessary.

Differences Between Bills

One major difference between the two bills has already been mentioned -- the House version contains no equivalent of the Mansfield Amendment. Another difference is that the House bill bans strip mining on the national forests in addition to the areas excluded in the Senate bill.

Furthermore, the House bill imposes a $2.50 per-ton tax on coal produced in both strip and underground mines. The tax would produce an estimated $400 million a year to be used in reclaiming abandoned strip mines. The Senate bill doesn't impose a tax but does establish a $100 million fund for reclaiming abandoned strip mines.

Congressional Approval Likely

It now appears likely that Congress will approve a mined-land reclamation act sometime next year. The ultimate wording will probably be a compromise between H.R. 11500 and S.425. In reality, the only remaining question is whether the Mansfield Amendment will survive the Senate/House Conference Committee. It likely will not; however, if the amendment is included in the measure sent to President Nixon, he may veto the bill.

# # # #

NGPRP PROGRESSING TOWARD JUNE, 1974 REPORT

The Northern Great Plains Resource Program (NGPRP) has a new manager. John D VanDerwalker, formerly with the Bureau of Sport Fisheries & Wildlife, became the program's fourth manager in October. VanDerwalker replaces Robert McPhail who became Regional Director of the Bureau of Reclamation in Billings. Previous articles on NGPRP appeared in Synthetic Fuels, December, 1972 p. 4-31, March, 1973, p. 4-5 and September, 1973, p. 4-23.

VanDerwalker inherited a tough job. NGPRP has a tremendous amount of ground to cover and is pushing hard to meet the June, 1974 deadline for the interim report. The interim report will be based on a series of investigations and studies conducted by work groups in seven principal areas of concern: regional geology; mineral resources; water (supply and quality); atmospheric aspects, surface resources; social, economic and cultural aspects; and national energy considerations. With the exception of the atmospheric aspects work group, most of the investigations will consist of a complilation of existing data.

Draft reports from each of the work groups must be completed by April 1, 1974. Each work group report will provide a regional profile, an identification of constraints to development and an impact analysis based on three levels of development provided by the energy work group: a base forecast, a most probable forecast, and an extensive development forecast.

Base Forecast

In developing the base energy forecast for the Northern Great Plains Region it was assumed that there would be no development of coal resources other than those necessary to meet regional demand and previously committed demand. It was also assumed that there would be no synthetic gas industry in the region.

Most Probable Forecast

In the most probable forecast scenario, personal incomes, population and other basic economic data were correlated with energy consumption and any important and consistent trends were extrapolated.

The estimated 1985 production of synthetic gas in the region is expected to be 578 billion cubic feet, or 26.0 percent of the projected U.S. synthetic gas production. Coal inputs necessary to achieve this production of synthetic gas will total 53 million tons in 1985.

In the year 2000, the region is expected to produce 1.3 trillion cubic feet of synthetic gas (21.6 percent of expected total U.S. synthetic gas production). Coal inputs required for this level of production will total 120 million tons.

Extensive Development Forecast

The extensive development forecast was derived under the following considerations and assumptions: (a) the nation would receive the lowest possible imports of natural gas

TABLE 1

NORTHERN GREAT PLAINS RESOURCE PROGRAM
ALTERNATIVE DEVELOPMENT SCENARIOS

Item and Year	Base Forecast	Most Probable Forecast	Extensive Development Forecast
Coal Production (million tons annually)			
1971 (actual)	21.3	21.3	21.3
1975	52	52	52
1980	91	107	160
1985	108	192	382
2000	144	362	977
Synthetic Gas Production (billion cubic feet annually)			
1980	0	0	578
1985	0	578	1650
2000	0	1320	3383
Synthetic Gas Plants (number of 250 MMcf/d plants)			
1980			
North Dakota	0	0	4
Montana	0	0	3
Wyoming	0	0	0
1985			
North Dakota	0	2	6
Montana	0	3	8
Wyoming	0	2	6
2000			
North Dakota	0	7	17
Montana	0	6	15
Wyoming	0	3	9

from Canada as estimated by the Canadian government; (b) there would be a lag in national nuclear generating capacity reaching 20,000 Mw by 1985 and 240,000 Mw by 2000; (c) that a reduction in oil imports for the United States would result in a 3 million barrel per day national petroleum shortage in 1985 and a 5 million barrel per day shortage by 2000. On this basis, coal production in the region is projected in Table 1.

In predicting the production of synthetic gas, it was assumed that the difference in imports of natural gas must be made up through coal conversion to synthetic gas and that one-half of this conversion would take place in the Northern Great Plains Region.

Forecasts Summarized

The estimated coal production, synthetic gas production and the number of gasification plants for each of the three development scenarios are summarized in Table 1.

Questions Remain

It is recognized that a number of significant information gaps will exist after release of the June report but it is still not clear how the program will proceed beyond that date. Lawrence Lynn, Assistant Secretary of the Interior and Chairman of the program review board, stated at a recent Denver meeting that the June report will be advisory and "subsequent studies are going to be needed."

In view of the slow start the program experienced and the brief period allowed for investigation and analysis, it appears that a rather significant amount of study will remain after completion of the interim report. Thus the role the report plays in federal decision making, i.e. will major development decisions such as renewed leasing be made next summer after the report is released, remains to be seen.

Report on Regional Profile of Water Completed

The Northern Great Plains Resource Program Water Work Group has completed its report on the Regional Profile of Water for the Fort Union Region. This work group is headed by Phil Q. Gibbs of the Bureau of Reclamation in Billings, Montana.

The report states that even though almost every stream in the Fort Union Region is over appropriated by paper water filings, there is still a large unused water resource within the Fort Union coal region which can be made available for future uses within the area. Two physical factors limiting water development are: (1) the finite quantities of water and (2) the storage which can be developed to impound surplus water. Social, environmental and economic factors are also seen as limiting factors of water development by the Work Group.

Unconsumed water over a long time period (1898-1972), adjusted to the 1970 level of development, is about 8.8 million AF in the Yellowstone River, so that a large quantity of water could be developed for future industrial need.

The report contains a compilation of existing reservoirs in the Fort Union coal region and water options and pending applications from these reservoirs which are reproduced in Tables 2 and 3.

The report states that groundwater data for the region are rather sparse, but initial indications are that the large quantities of water required for most industrial operations could not be served entirely by groundwater sources.

In conclusion the reports states, "from an analysis of the hydrology of the Fort Union coal region, it becomes quite apparent that the unregulated rivers within and flowing past the area do not have the potential to offer opportunity for further diversions in their current flow regimes except seasonally. Only by constructing storage reservoirs can the functions of low flow augmentation, flood control, irrigation development, or new industrial uses be served."

# # # #

TABLE 2

Existing Major Reservoirs in Fort Union Coal Region

River Basin	Reservoir	Storage in Thousand Acre-Feet				Uses
		Inactive and Dead	Active	Flood Space	Total	
Missouri	Fort Peck	4,300	11,100	3,700	19,100	R, FC, Irr., N, P, M, I
	Lake Sakakawea	5,000	13,500	5,900	24,400	R, FC, Irr., N, P, M, I
Milk	Nelson	18.7	66.8	-	85.5	R, Irr.
Clarks Fork Yellowstone	Cooney	0	24.4	-	24.4	R, Irr.
Wind-Bighorn	Bull Lake	0.7	151.8	-	152.5	R, Irr.
	Pilot Butte	5.4	31.5	-	36.9	P, Irr.
	Boysen	252.1	549.9	150.4	952.4	R, FC, Irr., P, M, I
	Anchor	0.1	17.3	-	17.4	Irr.
	Buffalo Bill	48.2	373.1	-	421.3	R, Irr., P.
	Bighorn	502.3	613.7	259.0	1,375.0	R, FC, Irr., P, M, I
	Upper Sunshine	1.0	52.0	-	53.0	Irr., S, D, I
	Lower Sunshine	1.9	54.9	-	56.8	Irr., D, S, P, I
Powder	Lake DeSmet	0	239.0	-	239.0	R, Future Industry
Tongue	Tongue Reservoir	5.9	68.0	-	73.9	R, Irr., M, I
Heart	Dickinson	1.2	5.5	-	6.7	R, Irr., M, I
	Heart Butte	6.8	69.0	150.5	226.3	R, FC, Irr., M, I
Grand	Bowman-Haley	4.3	15.8	72.9	93.0	R, FC, M, I
	Shadehill	58.2	30.0	269.6	357.8	R, FC, Irr.

R - Recreation FC - Flood Control Irr. - Irrigation N - Navigation P - Power M - Municipal I - Industrial
S - Stockwater D - Domestic

TABLE 3

Water Source	Water Options in Effect or Pending	Additional Applications
Boysen Reservoir	85,000	59,000
Yellowtail Unit	623,000	630,000
Tongue River Reservoir	4,175	0
Moorhead Reservoir	-	220,000
Fort Peck Reservoir	-	310,000
Lake Sakakawea	-	124,000
Lake Tschida	-	18,000
Yellowstone River	-	630,000
Totals in Fort Union and Powder Basin Coal Region	712,175	1,991,000

WYOMING DEPAD COMPLETES REPORT ON FUTURE ENERGY DEVELOPMENT IN THE POWDER RIVER BASIN

The Wyoming Department of Economic Planning and Development (DEPAD) recently completed a preliminary draft of a report on future energy development in the Powder River Basin. The report presents an overview of the coal reserve, the water resources and the economy of the region as it exists today, then projects population growth that can be expected in each county as a result of energy development.

Area Affected by Strip Mining

Contrary to what might be considered popular belief, most of the Powder River Basin will not be torn up by strip mining of coal. The area underlain by strippable coal in the Wyoming Powder River Basin totals 70,560 acres which represents approximately 0.4% of the surface area of the basin. If the entire 70,560 acres is mined and 1-1/2 times this amount of land is required for roads, buildings, top soil storage and other associated mining activities, then approximately 176,400 acres would be disturbed, which is approximately 2.2% of the Wyoming Powder River Basin surface area. The report doesn't provide an estimate of additional acreage that would be affected by railroad lines, the housing of new employees and construction of energy conversion facilities.

Water Resources

One of the major constraints to development in the Powder River Basin is a lack of available water. Probably the main impediment to water development for the basin, the report states, is the Yellowstone River Compact, (Session Laws of 1951, Ch. 10), which allocates the unappropriated and unused waters of the Clarks Fork River, Big Horn River (excluding the Little Big Horn), Powder River (including Little Powder River) and the Tongue River between Montana and Wyoming. Although the compact reserves a considerable amount of water for use in Wyoming, it cannot be used outside the drainage basin of the Yellowstone without the consent of the signatory states which are Wyoming, Montana and North Dakota.

Unfortunately for coal development in the Powder River Basin, most of the strippable coal that is under lease lies outside of this drainage area, the report states.

Wyoming Entitled To 2,446,000 AFY

The average unappropirated and unallocated flow of water from the Powder River and the Tongue River is 528,000 AFY. Wyoming is entitled to 40% of the Tongue River and 42% of the Powder River, a total of 217,000 AFY, under the terms of the Yellowstone Compact. The Bighorn and the Clarks Fork Rivers have an average unappropriated and unallocated flow of 3,233,800 AFY and the compact entitles Wyoming to 2,229,000 AFY. Thus the total amount of unappropriated and unallocated water available to Wyoming under the terms of the compact, according to the report, is 2,446,000 AFY.

The U.S. Bureau of Reclamation is currently authorized to option 547,000 acre-feet of industrial water from Yellowtail and Boysen reservoirs, and of this amount 457,000 acre-feet are already under option. It should be noted, however, that the Bureau's authorization for marketing industrial water from these reservoirs is being challenged by a suit filed by the Environmental Defense Fund and others. See page 4-44 for a discussion of the suit. The remaining 100,000 acre-feet has been reserved by the Department of the Interior until completion of the Northern Great Plains Resource Program, the report states. "The final use and the means of conveyance of this water is still in the planning stages," the report notes, "but even if a pipeline is built, the water could not be used outside the Yellowstone River drainage basin without a legal determination."

Coal Reserves Near Gillette Outside Basin

The large coal reserves south and east of Gillette are located outside the drainage basin of the Yellowstone River and lie in an area drained by the Belle Fourche and Cheyenne Rivers. The average unappropriated and unallocated water in the Belle Fourche River is 87,000 acre-feet, but after allowances for future stock and domestic uses, Wyoming's 10% share is only 7,300 acre-feet. A provision of the Belle Fourche Compact, however, states that no reservoir can be built with a capacity in excess of 1,000 acre-feet if the water is to be used solely in Wyoming (Session Laws of Wyoming 1943, page 153). "This almost eliminates using any water from the Belle Fourche River for development of coal in the Powder River Basin," the report states.

The Cheyenne River is much the same as the Belle Fourche, the report states, but it has not been compacted and there are no firm estimates as to how much water could be developed. The U.S. Corps of Engineers has studied the river, however, and concluded that there are no feasible projects.

Groundwater is a Possible Source

Groundwater is a definite possibility for developing the coal, the report notes, but before groundwater could be developed an extensive drilling program would have to be initiated to determine potential yields. The Madison and Minnelusa formations have huge volumes of water but are very deep (7,500 to 12,000 feet below surface in Campbell County) and the water has a high dissolved salt content (3,000 to 200,000 ppm). The report states that if drilling was initiated at the recharge areas, west flank of the Black Hills or the east flank of the Big Horn Mountains, both the drilling cost and the salinity would be lower but transportation costs much greater. In general, the report concludes, the problems and potential for development of this groundwater are to a large extent unknown.

Green River is Another Possible Source

Another alternative the report discusses is diversion from the Green River. This approach has several advantages, the most significant being that the water could be used in the area south of Gillette. Under the terms of the Colorado River Compact, Wyoming is allocated 1,043,000 acre-feet from the Green River and about 100,000 AF of this water is available for use outside the Green River Basin. "At the present time," the report states, "it would seem that groundwater will be developed for use in the coal fields before any transbasin diversion; however, groundwater will probably be only a stop-gap measure until much larger quantities of water can be diverted into the Powder River Basin coal fields."

A final source the report points to are water rights that predate the Yellowstone Compact. It is possible, the report states, that these water rights might not be subject to the terms of the compact and could furnish an additional 25,000 AFY for industrial use.

Profile of Future Growth

The primary purpose of the report is to provide information to the state and local governments on the impact of future mineral development in the region. Consequently, DEPAD conducted a survey of 27 companies with interest in the basin in order to determine how many projects were planned. A shortcoming of this methodology is that only those companies with holdings were surveyed, neglecting companies who might acquire them in the future. Based on these interviews, DEPAD developed projections of population and employment for the basin as a whole and for each county to the year 1990. The projected population for the Powder River Basin in 1990 is 216,461 as compared to 107,364 in 1970.

For Campbell County alone, DEPAD projected a population of 56,959 in 1990 compared to 12,957 in 1970. The survey revealed that more projects were planned for Campbell County than for any other -- a total of 13, including a proposed railroad line, four coal mines, three coal gasification or liquefaction plants, one power generation plant and one uranium mine.

In Converse County, the DEPAD survey identified four projects, all uranium mining and milling operations. The county population is projected at 16,091 in 1990 compared to 5,938 in 1970.

Two projects were identified in Johnson County, a uranium mine and mill and a gaseous diffusion plant. Since the survey was conducted, however, Reynolds cancelled the Lake DeSmet development. At any rate, the county population is projected at 18,537 in 1990 compared to 5,587 in 1970.

The survey didn't identify a single proposed energy project in Sheridan County. Four projects, however, including three coal mines and a coal gasification plant were identified in southern Montana near the Wyoming border. Some of the population influx from these developments would have an impact in Sheridan County, the report states. The projected population for Sheridan County in 1990 is 38,192 compared to 17,852 in 1970.

The report also provides detailed socio-economic and population characteristics for each of the four counties.

# # # #

GASIFICATION PLANTS IN N.D. CONSIDERED AS PUBLIC UTILITIES

Coal gasification plants in North Dakota will be considered as public utilities and therefore will be subject to regulation by the State Public Utilities Commission (PUC). Status as public utilities also means that gasification plants must apply to the PUC for a certificate of public convenience and necessity and be the subject of public hearings.

The North Dakota PUC pointed these facts out last September to companies contemplating construction of gasification plants in a letter which quoted the following North Dakota statutes:

"49-02-01. GENERAL JURISDICTION OF THE PUBLIC SERVICE COMMISSION OVER PUBLIC UTILITIES. The general jurisdiction of the commission shall extend to and include: .....(5) Gas companies for the manufacture and distribution of gas, natural or artificial;"

"49-03-01. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY SECURED BY PUBLIC UTILITY. No public utility henceforth shall begin the construction or operation of a public utility plant or system or extension thereof, without first obtaining from the Commission a certificate that public convenience and necessity require, or will require, such construction and operation....."

Classification as a public utility also means that gasification plants will be heavily taxed. Kenneth Jakes of the North Dakota Tax Department said that if gas plants are viewed as utilities, then they can be assessed by the state and taxed on their land, buildings and operating equipment. If not classified as utilities, however, gasification plant equipment would qualify for personal property tax exemption.

Jakes theorized that if equipment is 80 percent of a gas plant's value and total investment in the plant is $500 million, then a company would pay up to $8.5 million a year in taxes as a utility. If not a utility, then taxes could be $1.7 million - a difference of nearly $7 million in state and local revenue.

# # # #

FPC DECIDES EXTENT OF JURISDICTION OVER COAL GASIFICATION

In April 1973 the Federal Power Commission requested that legal briefs be filed by June 15 for the purpose of determining FPC jurisdiction over coal gasification plants and the product gas from such plants. The FPC action involved applications related to two separate proposed coal gasification projects in New Mexico. The FPC consolidated the two applications for the purpose of determining the extent of the Commission's jurisdiction over coal gasification projects.

The two applications were reviewed in the Dec. '72 and March '73 issues of this report. The first application to the FPC, submitted by El Paso Natural Gas Company, asked only for authority to build minor connecting pipeline facilities needed to move the pipeline quality gas from a proposed coal gasification plant into interstate commerce. In the second application, however, Pacific Lighting and Texas Eastern asked FPC for permission to build their proposed coal gasification plant. It was this disparity which prompted the FPC to consolidate the two applications and to request the legal briefs.

The Federal Power Commission, on September 4, 1973, ruled that it doesn't have authority to regulate directly the price of gas made from coal; however, if the product of coal gasification is blended with natural gas for sale to consumers then the price for such a mixture would fall under FPC jurisdiction. The decision is consistent with one made last year by FPC that it lacked jurisdiction over syngas produced from naphtha until mixed with natural gas.

# # # #

SUPPLEMENTAL FPC APPLICATION INDICATES CHANGES IN EL PASO'S BURNHAM PROJECT

On October 8, 1973 El Paso Natural Gas Company filed a second supplement to its application (Docket No. CP73-131) for a certificate of public convenience and necessity authorizing construction and operation of a tap and valve assembly and a synthetic gas purchase meter on El Paso's 34-inch San Juan mainline in San Juan County, N. M. Authorization was also sought for the transportation and sale in interstate commerce for resale of synthetic gas to be produced from the gasification of coal at the Burnham Complex and introduced in El Paso's mainline at the proposed tap and valve assembly. The original application, which was filed on November 15, 1972, was reviewed in the December 1972 issue of Synthetic Fuels, page 4-1.

The purpose of tnis supplement is to update the original application and to further clarify the various technical and economic features of the Burnham Project such as the updating of capital, operating and maintenance costs, the occurrence of certain design and capacity changes that have been made since November 15 of last year, the updating of Southern Division System supply and market data, and the expected supply and rate impact on the Southern Division System of the transportation and sale for resale of the synthetic gas volumes proposed.

The Burnham Coal Gasification Project as updated by the latest supplement is designed to produce 288,600 Mcf per day of 954 Btu/cf synthetic gas. Over the twenty-five year life of the project some 274 million tons of coal will be mined from approximately 11,250 acres. Up to 1.4 million tons of this annual production of coal will, after crushing, be in the form of fines too small to gasify (less than 2 millimeters) and are proposed to be marketed. The remaining coal (1,177 tons per hour) will be used as gasification feedstock at the Burnham Complex.

Approximately 9,500 acre-feet of water per year will be consumed in Burnham project mining and gasification operations. About 81% of the water consumed will be for in-plant uses with the remainder for non-plant use.

The initial capital investment required for the mining operation to be undertaken by Mesa Resource Company, a subsidiary of El Paso, is estimated at $113,520,000. The capital investment required for the coal gasification facility to be built by Fuel Conversion Company, another El Paso subsidiary, is estimated at $491,350,000. El Paso's capital investment is estimated at $809,143. The average unit cost of the synthetic gas over the twenty-five year plant life is estimated at $1.17 per Mcf.

Many changes have been made and those of importance are summarized following.

Pipeline

The synthetic gas pipeline's diameter has been changed from 24 inches to 30 inches due to increased plant capacity. Also, the water pipeline now parallels the existing El Paso mainline from the plant to the San Juan River and will have a design capacity of 28,250 AFY.

Plant Operation

The 1978-79 heating season will now be the first heating season during which the full production volume of synthetic gas from the Burnham Complex will be available. The synthetic gas production rate has been increased to 288,600 Mcfd as compared to the previously indicated 250,000 Mcfd.

Total Gas Supply Data

The currently anticipated supplies of gas available to the El Paso Natural Gas Company's Southern Division through the year 1981 are reflected in Table 1. Two new sources to supplement conventional gas supply are expected to come onstream in late 1977 and early 1978. The synthetic gas produced in the Burnham Complex is one new source and the second is El Paso's project for importing LNG from Algeria which is expected to supply gas to the Southern Division through displacement arrangements with Transco at a rate of 372,500 Mcfd. Table 2 summarizes the Southern Division's expected gas requirements, sales and deficiency for the years 1974 through 1981.

Table 1

Total Gas Supply Data For El Paso's Southern Division Through 1981*

	Total Available Gas Supply (Average MMCFD)								
	1973	1974	1975	1976	1977	1978	1979	1980	1981
Conventional Sources	3,955	3,555	3,032	2,747	2,507	2,281	2,100	1,956	1,812
LNG Project	--	--	--	--	53	309	373	373	373
Burnham Coal Gasification Project	--	--	--	--	--	208	263	263	263
Total	3,955	3,555	3,032	2,747	2,560	2,798	2,736	2,592	2,448

*Compiled From Data in FPC Docket No. CP73-131

Table 2

El Paso Natural Gas Co.
Southern Division

Summary of Estimated Requirements, Sales and Deficiency for the Year 1974 through 1981*
(TCF/yr.)

Year	Requirements	Sales	Deficiency
1974	1.507	1.147	.360
1975	1.524	.976	.548
1976	1.531	.890	.641
1977	1.534	.847	.687
1978	1.529	.898	.631
1979	1.546	.903	.643
1980	1.550	.859	.691
1981	1.568	.813	.755

*Compiled From Data in FPC Docket No. CP73-131

Cost of Service

The cost of service of the synthetic gas during its first three full years of operation of the Burnham Complex will be $1.51, $1.49, and $1.47 per Mcf respectively. This compares with a cost of $1.21, $1.18 and $1.15 for the first three years as presented in the original filing.

The increase in the average cost of service per Mcf of gas sales due to the synthetic gas from the Burnham Complex during the first full year of operation (1979) will be 9¢/Mcf. The total cost of service for the Southern Division during 1979 is now expected to be $.54/Mcf.

Mining Plan and Equipment

The target date for full production at the mine has now been set as July 1, 1978 which reflects the revised timetable for the production schedule of the gasification plant. Production requirements have been increased to 10.78 million tons annually from the 8.84 million tons indicated in the original filing. This increase in production is the result of El Paso's decision to increase the design output of the gasification plant (from 250 MMcfd to 288 MMcfd) and to sell coal fines smaller than two millimeters rather than briquetting the fines for gasification, as originally indicated. Also, further analysis of the coal has resulted in a small downward revision of the average heat content of the coal.

The revised list of mining equipment is as follows:

No.	Items
1	110 Yard 310 Boom Dragline
1	110 Yard 310 Boom Dragline
1	110 Yard 310 Boom Dragline
1	Vertical Overburden Drill
2	Horizontal Overburden Drill
1	110 Ton Mobile Crane
1	50 Yard Dragline
1	75 Ton Lowboy Trailer
--	Fixed Electrical Equipment
1	Shop-Office-Warehouse
--	Shop Equipment
10	Miles Haul Road
1	Sewage Plant
1	Fire Trucks & Equipment
--	Mobile Elec. Equipment & Cable
2	25 Yard Loading Shovels
--	Training Facilities
8	150 Ton Haulage Trucks
4	125 Ton Ash Trucks
1	Front End Loader
1	Water Sprinkler
2	Rubber Tired Dozers
1	Road Grader
2	Coal Drill-Twin Mast
1	Ambulance-First Aid
--	Misc. Pit Equip. Including Expl. Ldr.
2	Bulk Anfo Trucks
12	D9 Bulldozers
2	Welding Trucks
2	Electrician Trucks
1	Prospect Drill
5	Autos
17	Pickup Trucks
--	Radios
4	Maintrip Buses
3	Spare Buckets D & S
1	Fuel Supply Truck
3	20 Yard Wheel Scrapers
1	Helicopter

The cumulative mine capital costs in 1973 dollars will be $78,331,000 over the 25-year life of the plant. Expected employment at the mine for both wage and salary employees will be 249 during the first five years and 264 for the remaining years.

Plant Description and Cost Estimates

Stearns-Roger Incorporated, engaged to do the basic design engineering of the Burnham Coal Gasification Complex, has revised certain process design features of the plant. However, the basic process steps and major process support and utility areas remain essentially unchanged from that originally presented.

Some of the more important changes are as follow:

(1) The minimum size of coal to be gasified has been reduced from 3/16 of an inch to 2 millimeters. Coal fines of a smaller size will be sold rather than briquetted for gasification as previously indicated. Some 850,000 tons of coal fines will be sold annually.

(2) The heating value of the end product synthetic gas will be 954 Btu per cubic foot rather than 972 Btu per cubic foot as previously indicated. The higher heating value would have required an inordinately higher capital investment.

(3) The production from the gasification plant has been increased from 250,000 Mcf per day to 288,600 Mcf per day. The total number of gasifier has been reduced from 30 to 28; four of these are spares.

(4) The oxygen and steam requirements of the complex have been reduced allowing these units to be smaller.

(5) Gas purification will use a single-step Rectisol unit rather than the two-step unit previously indicated. This change came about as a result of development work on methanation.

(6) Sulphur removal from low-Btu utility fuel gas will be more economically accomplished by the Stretford process than the hot potassium carbonate wash previously indicated.

(7) Biological treatment of recycle liquors has been eliminated since further development work has shown that this waste-water can be used as is.

(8) Methanation by-product steam pressure has been reduced from 1150 psia to 600 psia.

(9) Power steam pressure has been reduced from 1500 psia to 1150 psia.

(10) The coal storage, blending and screening facilities will be a part of the mine rather than the gasification unit.

Table 3 is a comparison of statistics for the Burnham Complex from data taken from the original November 1972 FPC application and the updated 1973 supplement. Of particular interest is the sharp increase in the total project cost.

# # # #

EL PASO SEEKS PERMITS FOR DEVELOPMENT GASIFIER

On August 15, 1973, El Paso Natural Gas Company filed an application with the New Mexico Environmental Improvement Agency for a permit to construct and operate its Development Coal Gasifier Project. Mesa Resource Company (an El Paso subsidiary) simultaneously filed its plan for opening a small surface coal mine to provide feed coal for the Development Gasifier with both the New Mexico Coal Surfacemining Commission and the Regional Mining Supervisor of the U.S. Geological Survey. Additionally, the Navajo Tribe of Indians and the U.S. Bureau of Indian Affairs were notified of El Paso's proposal, which is to be located on El Paso's Navajo coal lease on the Navajo Indian Reservation in San Juan County, New Mexico. El Paso previously filed an application with the Federal Power Commission for approval of a proposed accounting and rate treatment procedure for the project. Refer to page 4-1 of the March 1973 issue of this report for a discussion of the FPC application.

El Paso presently estimates that a total capital investment of approximately $19 million will be required for the project. Annual operating expenses are estimated in the range of $5 million. Following the required thirteen month construction period the contemplated life of the project is projected at three years.

Briefly, the Development Coal Gasifier Project consists of a single Lurgi coal gasifier unit and associated equipment, and a supporting coal surface mine. Its purpose is to provide a short-term research and development facility for the testing of certain technical and environmental aspects of commercial scale coal gasification facilities.

The tests will hopefully result in significant improvements in the commercial design of a coal gasification plant. Specific tests to be conducted are described following.

Recent operating experience at existing Lurgi gasifier units indicate the possibility of operating at a level 25% above the present Burnham design capacity. Accordingly, the auxiliary facilities will be sized to permit operation at a maximum level of 50% above normal design production rates. Also, the development gasifier will be designed to operate at a maximum pressure some 30% above the design pressure of existing commercial gasifiers. Successful operation of the

TABLE 3*

Burnham Coal Gasification Complex
Comparison of Statistics Between Original 1972
FPC Application and 1973 Supplement

	1972	1973
Start of Construction	Summer 1974	Spring 1975
First Heating Season Gas Available	1977-78	1978-79
Personnel Requirement (Plant and Mine)	941	1238[a]
Gasification Complex Capacity (MMcf/d)	250	288
Gas Heating Value (Btu/cf)	972	954
Gas Cost ($/Mcf)		
First 3-year average	1.18	1.49
25-year average	--	1.17
Coal Mine Capacity (MM ton/year)		
To Gasification Complex	8.62	9.38
Fines for sale	0	0.85
Refuse and loss	.22	.56
Total	8.84	10.79
Project Cost ($ million)		
Gasification Complex	353.2	491.4
Mine	67.2	113.5
Pipeline & tap	.7	.8
Total	421.4	605.7

*Compiled from data in FPC Docket No. CP73-131
a. Obtained from telephone conversation with El Paso personnel

gasifiers at the above mentioned conditions could greatly reduce the capital investment requirements of future commercial plants.

Additionally, tests will be conducted to ascertain optimum operating conditions. Among the parameters to be tested are: pressure, temperature, steam flow rate, oxygen flow rate, air flow rate, cycle time, coal bed depth, by-product formation and performance of the sulfur-recovery system. Certain mechanical modifications will also be tested such as improvements to the coal-lock system and the top coal distributor. Tests on gasification of smaller coal sizes will be conducted; hopefully, the need for briquetting large amounts of fines will be eliminated.

Operation of the gasifier will provide samples of by-products necessary for research and development work to be performed by potential customers in order to establish final product quality.

The development gasifier has been designed to operate with either air (for low-Btu gas) or oxygen, thereby permitting development work on both schemes. Current environmental constraints encourage the use of low-Btu gas for supplying plant fuel needs. Therefore, a gas-fired turbine-generator set will be installed for the purpose of proving the design of a combustion chamber capable of burning low-Btu synthetic gas from air-blown gasifiers. Such testing could lead to significant power-generation applications in future gasification plants, as well as in major power utilities and industrial facilities.

Pollution control equipment will also be tested and the final disposition of trace elements originating in the feed coal will be determined. In the sulfur recovery area, optimization of the Stretford process for high pressure and high CO_2 inlet concentrations will be determined.

The development gasifier will provide the facilities for training operators and other technical and maintenance personnel destined for employment in commercial gasification facilities. Surface restoration and revegetation tests will be conducted at the four test pit sites comprising the development mine. To this end El Paso hired the New Mexico Agricultural Experiment Station (NMAES) to conduct such experiments. The contract with NMAES is described in the September 1973 issue of this report, page 4-30.

# # # #

CONOCO METHANATION TESTS STARTED

In late September the Conoco methanation unit began operation as part of a program for developing a commercially and technically viable process for methanation of coal-derived gases to produce a synthetic pipeline quality gas. This unit is located at the Scottish Gas Board's Westfield, Scotland coal gasification plant.

The tests are being sponsored by an industry group headed by Conoco which includes:

AMAX Coal Co.
Cities Service Gas
Colorado Interstate Gas
Columbia Gas System Service
El Paso Natural Gas
Esso Research and Engineering
Gulf Mineral Resources
Natural Gas Pipeline Co.
Northern Natural Gas Co.
Pacific Coal Gasification
Panhandle Eastern Pipeline
Peabody Coal
Rocky Mountain Energy
Transcontinental Gas Pipeline
Transwestern Coal Gasification

The initial tests have apparently been quite successful. The unit has been taking a slipstream from the Lurgi gasification unit and producing a synthetic gas with a methane content as high as 95 percent.

Details are sparse but it is believed that the methanator is a fixed bed reactor employing a modified version of the British Gas Corporation's Catalytic Rich Gas process which recycles a portion of the product gas in order to control reactor temperature. This is necessary because the methanation process is extremely exothermic.

The Rectisol purification system is currently being used to remove sulfur from the gas stream before it enters the methanator. Later tests will employ the Benfield process as an alternate method of removing sulfur.

The methanator has a capacity of 10 MMcfd of purified raw gas and produces about 3 MM cfd of product gas. It has been operating at approximately 85 to 90 percent of designed capacity. Reportedly the catalyst is a high-nickel catalyst which will be tested over a 40-week period (20 weeks with Rectisol purification and 20 weeks with Benfield purification) to determine its expected life.

# # # #

METHANATION UNIT TO BE BUILT AT RAPID CITY PILOT PLANT

Consolidated Coal Company recently announced that a $1,685,000 contract was awarded to the Blaw-Knox Chemical Plants Division of Dravo Corporation for the construction of a methanation unit at the CO_2 Acceptor Pilot Plant near Rapid City, South Dakota. The methanation unit is expected to be onstream by July 1, 1974. It will raise the heating value of the CO_2 acceptor raw gas from about 350 Btu/CF to about 980 Btu/CF.

The CO_2 Acceptor pilot plant is being financed jointly by the Office of Coal Research and the American Gas Association. Consol is the operator.

# # # #

FOUR COMPANIES ANNOUNCE COAL PROJECTS FOR WYOMING

Announcements during recent months have given Wyoming residents an indication of the level of industrial development which may be expected for the state. Actions by Transcontinental Gas Pipe Line Corporation, Texaco Inc., Panhandle Eastern Pipe Line Co., and Carter Oil Co. reaffirm the interest which has developed in Wyoming's low sulfur coal reserves.

Transco To Evaluate Feasibility of Coal Gasification Project

On October 2, 1973, Transcontinental Gas Pipe Line Corp., a wholly owned subsidiary of Transco Companies, Inc., signed an option agreement with Stoltz, Wagner & Brown and Tipperary Corporation of Midland, Texas for joint development efforts of coal rights underlying more than 20,000 acres in the Powder River Basin of northeastern Wyoming. (Refer to Cameron Engineers' Coal Mineral Right Ownership map for the Powder River Basin, included in the pocket of the June 1973 issue of Synthetic Fuels, for location of leases).

Under terms of the agreement Transco is authorized to evaluate the quantity and quality of the coal. Based on the evaluation Transco will determine the feasibility of a coal gasification project for producing pipeline quality gas.

Texaco Acquires Reynolds' Reserves

On October 26, Texaco Inc. announced the signing of a letter of intent to acquire coal reserves estimated at two billion tons from Reynolds Metals Co. These reserves are located near Lake DeSmet (which is also owned by Reynolds) in Wyoming on some 37,000 acres held by Reynolds. Reynolds will retain certain land, coal and water rights in the area for future manufacturing operations.

Under terms of the agreement, Texaco is to pay Reynolds $25 million within 90 days of closing and a royalty based on production with provision for a minimum advance royalty of $12 million per year for each of the first 10 years. In addition to the coal the agreement calls for certain water rights to be assigned by Reynolds to provide Texaco with water resources to develop the coal reserves.

Panhandle Eastern Announces Gasification Plant For Wyoming

On September 26, Panhandle Eastern Pipe Line Co. announced that it intends to build a commercial coal gasification plant in the Powder River Basin of Wyoming; however, the company has not yet announced an exact location for the plant.

Panhandle has commitments for approximately 665 million tons of subbituminous coal in Campbell County under an agreement with Peabody Coal Co. Also, Panhandle retained M. W. Kellogg Co. and American Lurgi Corp. to evaluate the feasibility of constructing such a plant using Lurgi technology in January 1972. (See page 4-24 of the March 1972 issue of Synthetic Fuels).

The proposed gasification plant would produce about 90 billion cubic feet of pipeline quality gas annually (250 MMcfd) from 25,000 tons of coal per day. Estimated cost of the project, exclusive of mining facilities, will be in the range of $400 million. The plant and associated facilities will provide permanent employment for 800 to 1100 people.

Panhandle is in the process of obtaining water resources for this plant from several sources. Also, Panhandle Eastern and Peabody have hired Sernco Inc., a Denver-based corporation to study the environmental impact both of the proposed gasification plant and of the politically controversial strip mining operation which is essential to provide the large amount of coal need for the plant.

Carter Oil Announces Gasification Study

The Carter Oil Co., an affiliate of Exxon Corporation, announced on September 5 that it plans to study a possible coal gasification project in northeast Wyoming for the next 18 months. Favorable study results could lead to the construction of a $500 million plant in the Powder River Basin near Gillette.

Carter holds numerous state and Federal coal leases in the Powder River Basin, and also has an agreement with the Bureau of Reclamation for 50,000 AFY of water for industrial purposes from the Yellowtail Unit on the Big Horn River.

In an accompanying news release, Exxon Corporation announced that it has developed two processes for coal conversion, one for gasification and the other for liquefaction. This work was conducted in a Baytown, Texas refinery; Exxon has spent some $20 million since 1966 on this research.

Exxon plans to spend $10 million more on the initial phase of a planned two-stage development of the gasification and liquefaction processes. If succcessful, a second phase involving the construction of two large-scale pilot plants will be initiated. Expected cost of this second phase will be more than $145 million.

# # # #

GULF FORMS ENERGY COMPANY

Gulf Energy and Minerals Company (GEM) was recently formed as a new division of Gulf Oil Corporation to be responsible for corporate effort on energy sources other than crude oil or natural gas. The new company includes Gulf Mineral Resources Company, prominent in the exploration, mining and milling of uranium in the U.S. and Canada, and the Pittsburg and Midway Coal Company. The new company will also be responsible for the commercial development of processes to produce synthetic fuels and chemicals from coal, oil shale and oil sands.

Gulf recently announced the development of a new coal liquefaction process which resulted from bench-scale tests. This process, called the catalytic coal liquefaction (CCL) process, is based upon the company's extensive work in catalytic hydrodesulfurization of crude and residual oils. The CCL process is to be further tested on a pilot plant scale by the Gulf Energy and Minerals Company.

# # # #

NAS STUDY OF SURFACE MINED LAND REHABILITATION COMPLETED

The National Academy of Sciences/National Academy of Engineering report to the Energy Policy Project of the Ford Foundation by the Study Committee on the Potential for Rehabilitating Land Surface Mined for Coal in the Western United States is now completed, is in the final review stage, but is not yet publicly available. (Refer to June 1973 issue of Synthetic Fuels, page 4-39 for a discussion of the study outline.)

However, the study chairman, Thadis W. Box of Utah State University, felt that congressional committees, working on proposed strip mining and reclamation legislation, should have the benefit of reviewing the report and for that reason copies of the report were sent to several congressmen. The findings and recommendations of the study were read into the November 8, 1973 Congressional Record and, therefore, they are public information.

The most striking of the findings delineated by the study group is the impact water availability will have on the future development of western coal. According to the group, there is enough water to satisfy the requirements of surface mining operations and rehabilatation, but a major problem exists in trying to provide water for related on-and off-site uses for gasification, liquefaction or power generation. The environmental impact of providing water for the latter uses could far exceed the impact from coal mining alone.

For the above stated reasons the study group included in its recommendations that alternate locations (most likely at the point of energy consumption) be considered for energy conversion facilities and that adequate evaluations be made of options (including rehabilitation) for the various local uses of the available water.

Because the report has received such widespread publicity and because its contents may have influenced voting on Senate Bill S.425, the findings and recommendations inserted into the Congressional Record are reproduced in the following paragraphs.

Findings

1. Of the nearly 128 million acres in the western United States that are underlain by coal, approximately 1.5 million acres could be surface mined using current methods. Of these lands, about 92,000 acres, or 140 square miles, would be disturbed by 1990 in order to meet current projections of coal production. By the year 2000 projections indicate disturbance of about 300 square miles. By comparison, approximately 1.3 million acres, nearly 2000 square miles, have been disturbed to date by surface mining in the eastern coal fields. Approximately 57% of our remaining coal reserves lie in the West, about one-quarter of which can be mined by current surface methods. That quarter, nearly 27 billion tons, represents about a 45-year supply if all current national production were from that source. The year 2000 projections cited do not include production that might be associated with proposed gasification projects.

2. We believe that those areas receiving 10 inches or more of annual rainfall can usually be rehabilitated provided that evapotranspiration is not excessive, if the landscapes are properly shaped, and if techniques that have been demonstrated successful in rehabilitating disturbed rangeland are applied. However, we must emphasize that this belief is not based on long-term, extensive, controlled experiments in shaping and revegetating western lands that have been surface mined. Few such studies have been made, and those in progress have only a few years data to report. Nevertheless, much research has been done on revegetating western ranges, disturbed roadways, and other denuded areas in arid lands. We believe that the techniques developed in these studies can and should be adapted to the higher rainfall areas of the West. The drier areas, those receiving less than 10 inches of annual rainfall or with high evapotranspiration rates, pose a more difficult problem. Revegetation of these areas can probably be accomplished only with major, sustained inputs of water, fertilizer, and management. Range seeding experiments have had only

limited success in the drier areas. Rehabilitation of the drier sites may occur naturally on a time scale that is unacceptable to society, because it may take decades, or even centuries, for natural succession to reach stable conditions.

3. Rehabilitation of mined lands, however, requires more than achieving a stable growth of plants. If environmental degradation is to be avoided, the plants themselves should be a mixture of species capable of sustaining the former native animals. Suitably sheltered habitats for the wildlife can be formed by attempting to model the land in its former image. Such shaping may also help to satisfy aesthetic perceptions and may assist the control of erosion. Environmental protection also requires finding means to avoid the impact of surface mining on surface water and ground water. In these aspects--wildlife, aesthetics, erosion control, and water quality--pertinent data for rehabilitating mined land are virtually non-existent. The necessary research has barely begun.

4. The potential for rehabilitation of any surface mined area in the West is critically site specific. Nevertheless, some broad principles apply to all sites. The rehabilitation of a specific site will depend on the detailed ecological and physical conditions at that site, the projected land use for the site after mining, the available technology that is applied to the site, and the skill in applying that technology. Rehabilitation objectives may range from no treatment at all through the gamut of reshaping and revegetation, to complete redesign of the landscape.

5. Because natural ecosystems correlate well with climates and soils, plant communities can serve to identify the regional potential for natural or induced revegetation. The coal regions of the West support four major vegetation types: desert shrub, foothill shrub, Ponderosa pine and associated mountain brush, and prarie mixed grasses. Desert shrub areas are not easily revegetated and natural plant succession is extremely slow. In the foothill shrub areas, even the best methods may be subject to failure during drought years. The mixed grass prairies and the areas of pine and mountain brush, on the other hand, have a high potential for successful revegetation.

6. Although technology is currently available for rehabilitating most of the land that has been surface mined in the United States, little of it has yet been properly applied. In the West the proper application of proven technologies is particularly crucial if rehabilitation efforts are to be successful. The addition of each recommended item increases the probability of success and decreases the probability of failure. The absence of a climatic "safety factor" means that even supplying all the requirements will not guarantee success. Instead, successful rehabilitation requires a committment to the proper application of proven techniques at all the critical times. Competent people trained in rehabilitation techniques and trained in techniques for monitoring the results of their efforts are needed.

7. Present knowledge permits a partial assessment of the local and regional effects of mining and the potential for rehabilitation prior to commencement of operations. Information is currently available or is being developed to allow cognizant officials to coordinate programs for surface mining and rehabilitation in some areas in ways that could reduce irreversible environmental impacts. Unfortunately, the variability of institutional arrangements, particularly the uneven provisions and enforcement of existing state laws, may inhibit rehabilitation efforts.

8. Most state laws governing surface mining and rehabilitation in the West do not provide for adequate planning, monitoring, enforcement, and financing of rehabilitation. State agencies charged with enforcement are generally understaffed and underfinanced, impairing implementation of the intent of the law.

9. Water requirements for surface mining operations and rehabilitation practices are not large and should not seriously deplete aquifiers or compete with existing uses. However, disruption of natural drainage networks at mine sites may interfere with downstream water rights, and groundwater aquifiers that are intercepted by mining operations may be drained or subject to change in flow

patterns causing problems for established users.

10. Because water requirements are a major problem in western areas, water consumption and related on- and off-site environmental impacts that would result from conversion of coal by gasification, liquefaction, or its use for electricity generation could far exceed the impact from coal mining alone. Therefore, a broad range of alternatives must be considered in evaluating the environmental impacts of such operations.

Recommendations

1. We recommend that surface mining for coal should not be permitted on either public or private lands without the prior development of rehabilitation plans designed to minimize environmental impacts, to meet on- and off-site air and water pollution regulations, and to define a timetable for rehabilitation concurrent with the mining operation. The preplanning should be part of an original environmental impact analysis for the region and should clearly indicate the basis on which conditions at the proposed mine sites are evaluated. It is important that adequate provision for public participation be a part of the review of the preplans.

2. We recommend that minimum regulations governing the surface mining of coal be promptly established by Federal statute to provide for preplanning, monitoring, enforcement and financing of rehabilitation, and that the costs of these activities be financed by mining operations. We also recommend that rehabilitation management plans be made and enforced for a period sufficiently long to assure vegetative stability. We recognize that state and local governments may wish to impose further rehabilitation requirements to meet additional goals. The sharing of the responsibilities for regulating surface mining and rehabilitation in this way should be encouraged. Methods for public participation at these several levels of government should be improved.

3. Rehabilitation of surface mines on public lands should set the example of the best available planning and the most rigorous application of rehabilitation techniques. Administrative regulations of the Federal land management agencies should go well beyond what is demanded by statute, if technology is available. Permits and leases for mining coal on Federal lands should be so written as to demand the application of the most advanced rehabilitation technology.

4. Improvement of rehabilitation techniques and the reduction of environmental impacts depend critically upon monitoring and evaluation. Therefore, we recommend establishment of a comprehensive, non-industry program to monitor and evaluate the rehabilitation of all current and future coal surface mining operations. Through such experience, performance standards for rehabilitation can be based on technical knowledge. The evidence must include a complete baseline inventory of the existing ecology, geology, and hydrology prior to granting a permit and the establishment of a set of continuing observations to monitor the on-site and off-site effects of mining and rehabilitation. Such studies must also include the determination of the chemical properties of the soils and overburden and the hydrologic effects of surface mining on groundwater, surface drainage and water quality as affected both on-site and off-site. These data will be a necessary measure of what has been accomplished and serve as an essential guide for on-going and future operations. The observations should be verified by agencies independent of the mining operation because many years of objective observations are required and organizational continuity is essential.

5. Since mining and rehabilitiation involve many diverse economic, ecologic, engineering, hydrologic and social factors in complex interactions and feedback loops, we recommend that Federal research and development programs for coal include studies on total system approaches to energy resource mining, mined land rehabilitation, and energy conversion. Because rehabilitation depends upon qualified people, we recommend that the responsible governmental agencies develop interdisciplinary teams to assess the potential for rehabilitation of proposed mine sites and to conduct the research for rehabilitation.

6. Certain features of the landscape cannot be restored at any price. If irreplaceable historic, scenic, or archeological sites or endangered species occur in an area proposed

for mineral exploration or surface mining or if such values in a neighboring area would be irreparably damaged by such activity, no mining should take place without an extensive review of the consequences. In some cases artifacts may be salvaged or moved with minimal loss of their value to society. In those instances the salvage operation should be considered part of the cost of rehabilitation and charged against the mining operation. If such irreplaceable artifacts cannot be moved or protected, or if the the landscape and associated biota cannot be rehabilitated for social purposes, surface mining should be prohibited.

7. Modern technology provides opportunities for changed uses and design of new landscapes in mined areas. Overburden is a resource for these activities, not a waste material. We recommend that regional planning for subsequent land uses, such as rangeland parks, recreational areas, and urban disposal centers, take advantage of these opportunities.

8. The shortage of water is a major factor in planning for future development of coal reserves in the American West. Although we conclude that enough water is available for mining and rehabilitation at most sites, not enough water exists for large scale conversion of coal to other energy forms (e.g., gasification or steam electric power). The potential environmental and social impacts of the use of this water for large scale energy conversion projects would exceed by far the anticipated impact of mining alone. We recommend that alternate locations be considered for energy conversion facilities and that adequate evaluations be made of the options (including rehabilitation) for the various local uses of the available water.

# # # #

ENVIRONMENTAL DEFENSE FUND AND OTHERS FILE SUIT TO PREVENT USE OF WATER FOR COAL DEVELOPMENT

Several major environmental organizations and local farming interests filed suit on October 16, 1973 in the U. S. District Court at Billings, Montana in an effort to revoke industrial water rights for coal development in the Northern Great Plains. The suit alleges that the federal government has been secretly leasing large amounts of water to industrial users in violation of congressional acts limiting the use of such water to agriculture. Furthermore, the suit alleges, such leasing was done in violation of the National Environmental Policy Act of 1969.

Plaintiffs in the suit are the Environmental Defense Fund (EDF), the Natural Resources Defense Council, the Montana Wildlife Federation, the Northern Plains Resource Council, the Houghian Livestock Company, four irrigation companies and three individual farmers.

Named as defendants are the Interior Department, the Army Corps of Engineers, and top officials of these departments including Interior Secretary Rogers C. B. Morton and Gilbert G. Stamm, Commissioner of the Bureau of Reclamation.

Similar to Sierra Club Suit

The suit is similar in many respects to the suit filed against Interior in June 1973 by the Sierra Club except that the EDF suit concentrates on the use of water in the Northern Great Plains region. The Sierra Club suit (which was reviewed on page 4-34 of the September 1973 issue of Synthetic Fuels) asks that no further action concerning coal development in the Northern Great Plains be taken until both a comprehensive study of the area (such as the Northern Great Plains Resource Program) and a NEPA-required environmental impact statement are completed.

The EDF suit asks for essentially the same types of studies before industrial use of water is permitted. The EDF suit is specifically aimed at preventing the sale or release of water from Boysen, Yellowtail, Fort Peck, Heart, Butte and Garrison reservoirs under an "industrial water marketing program" which was instituted in 1967, until an environmental statement is completed.

In addition, the EDF suit asks that, until a comprehensive environmental impact statement is prepared, the Departments of Army and Interior be restrained from implementing the recommendations and proposals contained in the "North Central Power Study" and the "Appraisal Report on Montana-Wyoming Aqueducts" and those resulting from the Eastern Montana Basin Study and the Western Dakota Basins Study, neither of which is yet completed.

Suit Extremely Complex

The EDF suit is comprehensive and complex. As with the Sierra Club suit, it is impossible to predict what the net effect of the EDF suit will be, but one thing is certain: it does serve to further compound the Northern Great Plains situation. The prospects for an early solution to the problems plaguing proposed coal development in the region are not encouraging.

Specifically, the EDF suit asks the court for the following injunctive relief:

1. A preliminary and permanent injunction restraining defendants from:

(a) Taking any action: that would allow any of the private entities holding water option contracts under the "Industrial Water Marketing Program" to take any steps preparatory to diversion of Bighorn or Yellowstone River water as called for in the water option contracts; permitting the diversion of waters affecting the navigable waterways; or permitting industrial users to obstruct navigable waterways with pipelines and diversion and intake works unless and until a broad, detailed and comprehensive environmental statement relating to the overall program is prepared as required by the National Environmental Policy Act (NEPA) and an environmental impact statement is prepared, filed and made public with respect to each such diversion or obstruction when appropriate.

(b) Awarding any new water options contracts under the "Industrial Water Marketing Program," the Regional Program, or any other program for the sale and delivery of Bighorn, Yellowstone or Upper Missouri water or water from their tributaries or any reservoirs of these rivers for industrial and mining purposes unless and until the requirements of NEPA are met.

(c) Continuing with their current policies and practices that in any way, directly or indirectly, allow the further development or implementation of proposals called for and planned in the "North Central Power Study," the Aqueduct Study, the Eastern Montana Basin Study or the Western Dakota Basins Study unless and until a detailed environmental impact statement on the planned development of the Northern Great Plains is prepared, filed and made public as required by NEPA.

(d) Taking any action of whatever nature that would directly or indirectly cause or allow any of the private industrial firms holding water option contracts under the "Industrial Water Marketing Program" to take any step preparatory to diversion of Bighorn River, Yellowstone or Upper Missouri water or water from their tributaries or reservoirs thereon as called for in the water option contracts or in applications for industrial water unless and until a detailed plan is prepared and submitted to the court showing compliance with the provisions of the Federal Water Pollution Control Act Amendments of 1972.

(e) Taking any action of whatever nature that would directly or indirectly cause or allow any of the private industrial firms holding water option contracts under the "Industrial Water Marketing Program" to take any steps preparatory to diversion of Bighorn River Water unless and until the Federal defendants comply with the provisions of the Fish and Wildlife Coordination Act.

2. A mandatory injunction commanding the Bureau of Reclamation to stay and rescind the award of a license agreement to Intake Water Company until a detailed and comprehensive environmental impact statement is prepared, filed and made public as required by NEPA.

3. A mandatory injunction commanding the Army Corps of Engineers to enforce Section 10 of the Rivers and Harbors Act with respect to the diversion of any waters from the Bighorn, Yellowstone and Missouri Rivers and their tributaries affecting the navigable capacity of those rivers, and the creation of obstructions such as diversion and intake works.

4. A preliminary and permanent injunction restraining the defendants from taking any action of whatever nature that would directly or indirectly cause or allow private industrial firms to take water out of the Boysen or Yellowtail Reservoirs or diverting waters directly out of the Bighorn or Yellowstone Rivers or their tributaries until the defendants have undertaken a comprehensive, detailed study of the actual water needs and uses of irrigationists, farmers and ranchers and other agricultural water users downstream of said reservoirs.

5. A preliminary and permanent injunction restraining the defendants from awarding and executing any further water option contracts under the "Industrial Water Marketing Program" and from delivering or causing to be delivered any water under existing water option contracts unless and until water right adjudications are undertaken and completed in the states of Montana, Wyoming and North Dakota and under the Yellowstone River Compact Act.

6. A mandatory injunction commanding the defendants to comply with all relevant provisions of the Yellowstone River Compact relating to the appropriation, allocation and diversion of waters of the Bighorn and Yellowstone Rivers and their tributaries.

# # # #

CHANGE OF VENUE IN SIERRA CLUB SUIT DENIED

On August 24, 1973, Barrington D. Parker, U.S. District Judge for the District of Columbia denied a motion by the Interior Department, et al to transfer the Sierra Club suit (C.A. 1182-73) concerning coal development in the Northern Great Plains region to the U.S. District Court in Billings, Montana. The Suit, which was filed on June 13, 1973, was reviewed in the September 1973 issue of <u>Synthetic Fuels</u>, page 4-34; a copy of the complaint was reproduced in the Appendix of that issue, page A-1.

In requesting the change of venue, the government attorneys reasoned that, "Since the property and interests ultimately affected by this suit are situated far from the District of Columbia, the logical forum is in Montana where the trial judge presumably will be more familiar with the local problems and ramifications attendant to the planned projects; that the discovery and trial proceedings will involve persons situated in Northern Great Plains territory; and that transfer may discourage the filing of multiple suits."

"The Court," according to Parker's opinion, "is not persuaded. The issues in this suit do not appear to necessarily involve a close scrutiny of the various individual property interests affected. The basic controversy centers upon Federal administrative policy which is made, or at least coordinated, in the District of Columbia...The Court is aware that the outcome of this suit will significantly affect the lands directly involved, but the Court is not convinced that the issues central to this case are such that they require adjudication by a Montana Court or that the convenience of parties and witnesses and the interest of justice demand transfer."

Essentially, Parker is saying that the basic issue to be resolved is the interpretation and applicability of paragraph 102 of the National Environmental Policy Act (NEPA), and more specifically, whether there are "major federal actions significantly affecting the quality of the human environment." Barrington notes that "the D.C. Circuit, both at the appellate and district level, has had considerable experience and involvement with so called 'NEPA' cases which often have broad, if not national impact."

<u>Motion for Summary Judgement Contemplated</u>

It is noted in Judge Parker's opinion concerning the change of venue that the Sierra Club intends to file a motion for summary judgement in the case. As of late November, however, no such motion had been filed.

<u>Applications for Intervention Granted</u>

As of October 12, applications to intervene as defendents had been granted to the following organizations and individuals:

American Electric Power System
Arkansas Power and Light Co.
Atlantic Richfield Co.
Cities Service Gas Co.

Crow Tribe of Indians
Kerr-McGee Corporation
Montana Power Co.
Northern Natural Gas Co.
Oklahoma Gas and Electric Co.
Panhandle Eastern Pipeline Co.
Patrick J. McDonough
Peabody Coal Co.
Portland General Electric Co.
Puget Sound Power & Light Co.
Washington Power Co.
Westmoreland Resources
Wisconsin Power and Light Co.

# # # #

STUDIES ON COAL DEVELOPMENT IN NORTHERN PLAINS RECAPPED

A number of studies which attempt to assess some aspect of coal development in the Northern Great Plains have either been completed, are contemplated or are underway. Some of these studies, like the Northern Great Plains Resource Program, are regional in scope while others deal with isolated aspects of coal development on a local or site specific basis. In the belief that a compilation and description of these numerous studies would be useful, brief reviews of several of the studies are presented herein. Table 1 is a concise summary of the reviews.

Northern Great Plains Resource Program

NGPRP is an interagency study of the ramifications of coal development in the Powder River Basin and Fort Union Region. The program was first announced in October of 1972 and will issue an interim report in June of 1974. Participating Federal agencies include the Department of the Interior, Environmental Protection Agency and Department of Agriculture. State involvement consists of membership in the program review board and management team.

The NGPRP interim report will be based on a series of investigations and studies conducted by work groups in seven principal areas of concern: regional geology; mineral resources; water (supply and quality); atmospheric aspects; surface resources; social economic and cultural aspects; and national energy considerations. With the exception of the atmospheric aspects work group, most of the investigations will consist of a compilation of existing data.

More than $1 million is being spent on the program by the federal government; the former program manager estimates that total funding is close to $3 million if the salaries of the manpower used in the program are included. See the article on page 4-26 and previous articles in the March 1973 issue of Synthetic Fuels, page 4-5, and the September 1973 issue, page 4-23 for more information.

North Central Power Study

In October 1971 a coordinating committee comprised of representatives of the U.S. Bureau of Reclamation and 35 major private and public electric suppliers issued a report on the electric power generation potential of some 250,000 square miles of Wyoming, eastern Montana, and western North and South Dakota. The report identified 42 potential sites for coal-fired power plants where coal and water resources were adequate for the generation of 200,000 megawatts of power. In identifying this potential, the report focused attention on the region and sent a shiver through environmentalists across the nation.

Appraisal Report on the Montana-Wyoming Aqueducts

This report was prepared by the Bureau of Reclamation and released in April of 1972. The report is based on studies of the availability of water resources in southeastern Montana and northeastern Wyoming. Projected water requirements for electric generation and synthetic fuels plants in the region, the reports states, total 2.6 million acre-feet a year by the year 2000. The study of water resources concludes that water requirements of this magnitude could be supplied by full development from existing and potential storage reservoirs and by construction of aqueducts to transfer the water to points of use. See Synthetic Fuels, June, 1972, p. 4-12 for more information.

Eastern Montana Basin Study

Another Bureau of Reclamation effort, this study was described in the recent Environmental Defense Fund suit as making preliminary

TABLE 1

SUMMARY OF STUDIES RELATED TO COAL DEVELOPMENT IN NORTHERN PLAINS REGION

Study or Report Title or Subject	Sponsors or Participants	Time Schedule	Budget
FEDERAL-STATE			
Northern Great Plains Resource Program	Depts. of Interior & Agriculture, EPA & States of Mont., Neb., N. & S. Dakota & Wyo.	Interim report due in June 1974	Estimates vary from $1 to $3MM
FEDERAL			
North Central Power Study	Bureau of Reclamation	Completed in Oct. 1971	Unknown
Appraisal Report on Montana-Wyoming Aqueducts	Bureau of Reclamation	Completed in April 1972	Unknown
Eastern Montana Basin Study	Bureau of Reclamation	Active	Unknown
Western Dakota Basin Study	Bureau of Reclamation	Scheduled for completion in July 1974	$300,000
Social Economic & Land Use Impacts of a Typical Coal Conversion Complex	Office of Coal Research-Denver Research Institute	21-month contract to be completed in mid-1974	$211,144
Environmental Problems of Siting Coal-Based Industrial Complexes	Office of Coal Research-Hittman Associates	A 30-month contract scheduled for completion in late 1975 or early 1976	$586,406
Project SEAM	Department of Agriculture	A 5-year study to be completed in 1978	Estimated at $30 million
Decker-Birney Resource Study	Forest Service & Bureau of Land Management	Completed in 1973	Unknown
STATE-MONTANA			
Coal Dev. in Eastern Montana	Montana Coal Task Force	Completed in January 1973	Unknown
Land Use Policy Study	Montana Environmental Quality Council	Scheduled for completion in 1975	Unknown
Energy Policy Study	Montana Environmental Quality Council	In early stages of develop.	Unknown
Water & Eastern Montana Coal Development	Montana Environmental Quality Council	Completed in November 1973	Unknown
Draft Environ. Impact Statement, Decker Coal Co. Mine	Department of State Lands	Completed in August 1973	Unknown
STATE-WYOMING			
Preliminary Draft, Energy Dev. in the Powder River Basin	Dept. of Economic Planning & Development	Completed in 1973	Unknown
Wyoming Framework Water Plan	Wyo. Water Planning Program, Div. of State Engineer's Office	Completed in May 1973	Unknown
STATE-NORTH DAKOTA			
Little Missouri Grasslands Study	North Dakota State Univ. with assistance from local, state & federal boards, commissions & agencies	Active, scheduled for completion end of 1973	$176,676
West River Diversion Feasibility Study	North Dakota State Water Commission	Active	$300,000
NON-GOVERNMENTAL ORGANIZATIONS			
Potential for Rehabilitating Lands Surface Mined for Coal in the Western United States	National Academy of Sciences	Completed 1973	Unknown
NAS/RANN Proposal for an Interdisciplinary Study of the Impact of Coal Development in the Fort Union Region of Montana & Neighboring States	National Academy of Sciences, National Science Foundation and University system of Montana	Seeking funding for a 3-year program	Seeking approximately $2 million

studies for an aqueduct system to convey water to coal fields in that portion of the region not covered by the "Appraisal Report on the Montana-Wyoming Aqueducts."

Western Dakota Basin Study

Scheduled for completion in July 1974, this $300,000 Bureau of Reclamation effort is a study of the economics, engineering and environmental problems associated with building a water pipeline that would handle 340,000 acre-feet of water from the Missouri River to supply industrial and municipal development in the western Dakota lignite area. The study is about half completed and proposes four alternative pipeline routes running 240-260 miles along the North Dakota lignite fields and into the Sturgis, S. D. area.

Office of Coal Research - Denver Research Institute

The Office of Coal Research (OCR) announced in September 1973 the award of a $211,144 contract to the Denver Research Institute (DRI) to study the social economic and land use impact of a typical coal-conversion complex in the Fort Union Region. Under the 21-month contract, DRI will study transportation systems, labor markets, public services, social issues, and other factors as a basis for future recommendations in regard to coal conversion projects.

Office of Coal Research - Hittman Associates, Inc.

OCR announced the award of a $586,406 contract last June to Hittman Associates, Inc. to study and seek solutions to environmental problems involved in the siting of coal-based industrial complexes. The regions to be considered in the study include Appalachia, Indiana, Illinois, Western Kentucky, the Great Plains and the coal areas of the Southwest.

The contract is for 30 months and calls for the development of information to define the relationship of geology, topography, soils, meteorology, hydrology and other characteristics to possible environmental effects. An evaluation will then be made of the approaches and techniques that can be used to minimize adverse environmental impacts during the construction and operation of the facilities.

Project SEAM

SEAM (Surface Environment and Mining) is the acronym given a 5-year, $30 million research, development and applications program by the U.S. Department of Agriculture. The initial efforts of the program focus on those portions of the West where large-scale mining operations are being planned in order to assure that fuels and other minerals are produced in harmony with a quality environment.

The basic objectives of SEAM are to advance knowledge and techniques for successfully rehabilitating mined areas and develop methods for planning mining operations so as to harmonize eventual utilization with rural development and environmental stewardship. SEAM will be closely coordinated with on-going federal and state programs such as NGPRP. For more information, see Synthetic Fuels, June, 1973, p. 4-38.

Environmental Impact Statements

As required by the National Environmental Policy Act, a number of impact statements have been prepared on individual coal developments in the Northern Great Plains. If two recent suits filed by environmental groups are successful, a comprehensive statement of the over-all impact of coal development on the entire region will be prepared. Those impact statements completed to date include the following:

(1) Big Sky Impact Statement. A NEPA statement has been completed for the expansion of the Peabody mine near Colstrip, Montana.
(2) Crow Indian Reservation Impact Statement. A draft NEPA statement has been completed by the Bureau of Indian Affairs for the strip mining of coal on the Crow Reservation in Montana.
(3) Crow Ceded Area Impact Statement. A NEPA statement has been completed for the Westmoreland Resources mining proposal on the Crow ceded area in Montana.

In addition, an environmental analysis has been prepared by the Bureau of Land Management for the Arch Minerals Coal Company mine near Seminoe Reservoir in Wyoming.

Decker-Birney Resource Study

The Forest Service and Bureau of Land Management conducted a joint study of an area planning unit in southern Montana in an effort to plan how coal development should proceed. After studying the resources of the unit, the study report concluded that strip mining of coal would destroy some of the other beneficial uses of the area and recommended that coal mining be allowed south of the line between townships 7S and 8S and prohibited north of that line. For more information, see Synthetic Fuels, March, 1973, p. 4-6.

Montana Coal Task Force

The Montana Coal Task Force was created in August 1972 to review anticipated and ongoing coal development in the state. Most of the state agencies were involved and the task force completed its work with publication of a situation report entitled "Coal Development in Eastern Montana" in January 1973. The report made a number of recommendations to the legislature which were enacted into law. For more information, see Synthetic Fuels, June, 1973 p. 4-23.

Montana Environmental Quality Council

The Council was created in September 1971 as a non-regulatory agency with the responsibility of anticipating environmental problems and recommending preventive and corrective measures. The Council is presently working on a land use policy study to be completed in 1975. Also planned is an energy policy study, for which some initial planning is already underway.

In September 1973 the Council released a report entitled "Water and Eastern Montana Coal Development" which makes recommendations on planning for the water development needed for coal development in eastern Montana. "The fact remains: eastern Montana coal will be mined and water will be consumed in the conversion of coal to other forms of energy," the report states. "The questions are: how much development will be done at what rate and in what manner." The report urges that water development take place in an orderly and well-planned manner rather than through a series of "non-decisions."

Department of State Lands

The department recently released a draft environmental impact statement on the Decker Coal Company mine. The statement says that the area being mined has large concentrations of saline-alkali soils which are a threat to revegetation of the mined land.

Wyoming Department of Economic Planning and Development (DEPAD)

DEPAD has completed a preliminary draft of a report on future energy development in the Powder River Basin. The report presents an overview of the coal reserves, the water resources and the economy of the region as it exists today, then projects population growth that can be expected in each county as a result of energy development. See page 4-30 for more information.

Wyoming Framework Water Plan

This plan identifies the long-range (50-year) alternatives for meeting the water needs of the state. It is an inventory of the state's water resources and related lands, a summary of present water uses, a projection of future water needs, and an identification of alternative decisions to meet or not to meet the projected future water needs. The initial phase of the State Water Plan was completed this year. See page 1-12 for more information.

Little Missouri Grasslands Study

Initiated in August 1972, this study has the objective of developing a multiple land use plan to guide future agricultural and industrial development in nine southwestern North Dakota counties. The study is being conducted by North Dakota State University with assistance from local, state and federal boards, commissions, agencies, private organizations and study area residents. Funding for the study totals $176,676 and completion is scheduled for the end of 1973. See p. 4-7 and a previous article in Synthetic Fuels, September 1973, p. 4-33 for more information.

West River Diversion Feasibility Study

This is a study initiated in July 1971 with the objectives of determining the feasibility for total development of the water and related land resources in a 14-county area of western North Dakota through utilization of the resources now available in the area; and to determine the feasibility and practicability of the diversion of waters from Lake Sakakawea to supplement the water supply throughout the various river systems in the area. The study is about half completed and funding is approximately $300,000.

The North Dakota State Water Commission is conducting the study and has contracted for work in the following areas where it lacks expertise:

(1) Lignite Study - Dr. Alan Fletcher, University of North Dakota
(2) Social Impact Analysis - Dr. John Bowes, University of North Dakota
(3) Environmental Impact - Dr. Richard Logan, Dickinson State College
(4) Socio-Economic Analysis - Dr. Dale Anderson, North Dakota State University.

National Academy of Sciences

A National Academy of Sciences study on the potential for rehabilitating lands surface mined for coal in the western United States was prematurely released recently. The study was commissioned as part of the Ford Foundation Energy Policy Project and concludes that the scarcity of water may limit the use of western coal. The report states that the key determinants to success in reclaiming strip mined lands will not be the cost of rehabilitation, but, rather, meticulous study of each mining site and the availability of water.

Furthermore, the report concludes that there simply is not enough water in the western coal states to permit the large-scale congregations of coal conversion facilities envisioned in the North Central Power Study. See page 4-41 for more information.

NAS/RANN Proposal for An Interdisciplinary Study of the Impact of Coal Development In the Fort Union Region of Montana and Neighboring States

This proposal was first drawn up in April 1973 and is presently being revised. Arnold Silverman, University of Montana, Missoula, is coordinating the proposal and says it will be resubmitted around December 1. The level of funding being sought is $2 million for a 3-year program.

Others

Many site-specific studies, too numerous to describe here, have been commissioned by industry. A substantial amount of work is also being done in the region by state and federal governmental agencies in carrying out their normal responsibilities.

After reviewing the numerous studies previously described, one thing stands out -- there isn't much coordination. This fact is very well illustrated by a study being conducted by the Water Resources Institute (WRRI) to identify water-related research needs associated with coal development. According to Dr. Dale Anderson, WRRI director for North Dakota, "This study is a study of studies to determine if more study is needed."

# # # #

appendix

APPLICATION OF

SHELL CANADA LIMITED

AND

SHELL EXPLORER LIMITED

TO THE

ENERGY RESOURCES CONSERVATION BOARD

APPLICATION

1. Shell Canada Limited and Shell Explorer Limited (collectively called the "applicants") hereby make application to the Energy Resources Conservation Board pursuant to Section 43(1) of The Oil and Gas Conservation Act for approval of a scheme or operation for the recovery of oil sands, crude bitumen and products derived therefrom within the area of Bituminous Sands Lease No. 13 issued by Her Majesty the Queen, in the right of the Province of Alberta.

2. Shell Canada Limited is a fully integrated oil company actively engaged in exploration, production, refining and marketing in Canada. Shell Explorer Limited (a wholly owned subsidiary of Shell Oil Company) participates in exploration in Canada pursuant to a joint venture agreement with Shell Canada Limited. The scheme or operation proposed in this application will be owned by the applicants in equal shares and will be operated by Shell Canada Limited.

3. The applicants propose to produce 100,000 barrels per day of synthetic crude oil. The applicants intend to commence construction of the major facilities by January 1, 1976 following a period of engineering and design and a review of the economics of full-scale production, with special emphasis on the impact of royalties and taxes for the life of the project. First production is scheduled to commence on January 1, 1980 with full-scale production to be achieved on or before January 1, 1982.

4. Lease 13 is held by the applicants in equal and undivided shares. A description of the lands included in the lease is set forth on the following page.

5. Particulars of the scheme or operation attached hereto form a part of this application.

6. The applicants submit that approval of this project will facilitate the orderly development of the Alberta tar sands in a manner consistent with the exercise of sound conservation and environmental protection practices.

7. Communications relative to this application should be directed to L. Korchinski at 1027 - 8th Avenue S.W., Calgary, Alberta, T2P 1J4.

Dated at Calgary, Alberta, this 28th day of June, 1973.

SHELL CANADA LIMITED

Assistant Secretary

Vice President

Attest:

SHELL EXPLORER LIMITED

President

DESCRIPTION OF LANDS COVERED BY LEASE 13

IN UNSURVEYED TOWNSHIP NINETY-FIVE (95), RANGE EIGHT (8), WEST OF THE FOURTH (4) MERIDIAN:

The West halves of Sections Six (6) and Seven (7), the North half and South West quarter of Section Eighteen (18) and Sections Nineteen (19), Thirty (30) and Thirty-one (31);

A N D

IN UNSURVEYED TOWNSHIP NINETY-FIVE (95), RANGE NINE (9), WEST OF THE FOURTH (4) MERIDIAN:

Sections One (1) to Thirty-six (36) inclusive;

A N D

IN UNSURVEYED TOWNSHIP NINETY-FIVE (95), RANGE TEN (10), WEST OF THE FOURTH (4) MERIDIAN:

Sections One (1) to Five (5) inclusive, Sections Eight (8) to Seventeen (17) inclusive, Sections Twenty (20) to Thirty-six (36) inclusive and those portions of Sections Six (6), Seven (7), Eighteen (18) and Nineteen (19) lying North and East of the right bank of the Athabasca River;

A N D

IN TOWNSHIP NINETY-FIVE (95), RANGE ELEVEN (11), WEST OF THE FOURTH (4) MERIDIAN:

Those portions of Sections Twenty-four (24), Twenty-five (25), Thirty-five (35) and Thirty-six (36) lying North and East of the right bank of the Athabasca River;

All statutory road allowances and what would be statutory road allowances, if the lands were surveyed pursuant to The Alberta Surveys Act, lying within and immediately to the South and West of the above described general area, containing an area of Forty-nine Thousand, Eight Hundred and Seventy-two (49,872) acres, more or less.

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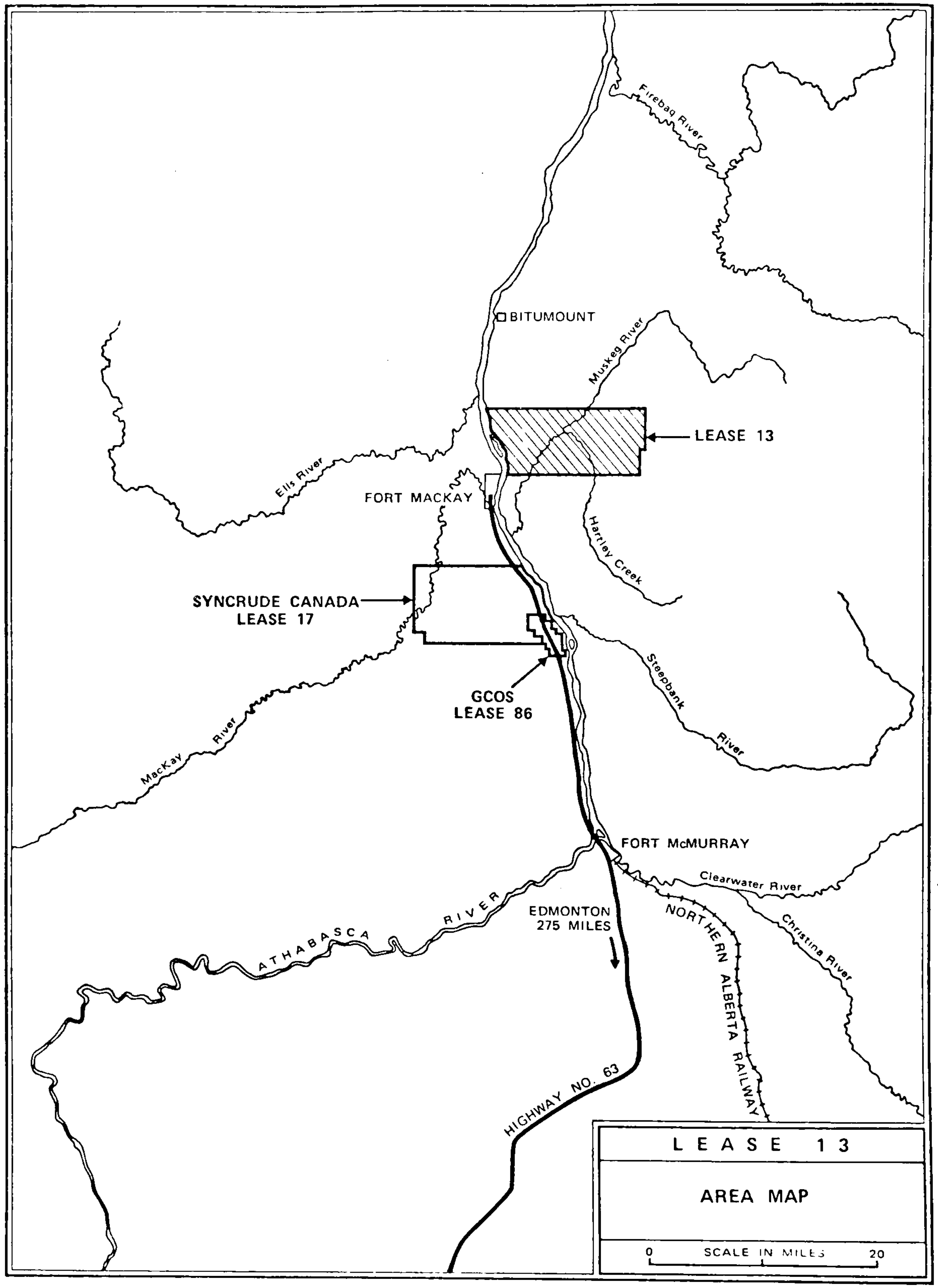
I LOCATION

The Athabasca area map that follows locates Lease 13 in relation to other major points of interest in the Fort McMurray area.

The centre of Lease 13 is 8 air miles from Fort MacKay, 38 miles from Fort McMurray, and approximately 275 miles north-east of Edmonton.

Access from Edmonton to Fort McMurray is by all-weather highway, air, or rail. Summer access to the lease is presently by river, or by use of a sand air-strip. Land transportation is possible in winter.



II GEOLOGY

A. GEOLOGICAL SETTING

The Athabasca tar sands contain the largest of several heavy oil accumulations in a 600 mile arcuate trend extending from the Peace River area of Alberta to the Lloydminster area of Saskatchewan. The tar in place in this trend, which totals some 750 billion barrels, is trapped in Lower Cretaceous sandstones associated with the updip margin of the Alberta sedimentary basin. Of this tar, approximately 625 billion barrels are located in Athabasca. The primary reservoir is the McMurray formation, a complex deposit of meandering channel sands, silts and clays that sometimes exceeds 300 feet in thickness. This deposit represents an alluvial-deltaic environment with marine incursions. The McMurray formation is overlain by marine Clearwater shales and sandstones and rests unconformably on Devonian sediments.

The McMurray formation in Lease 13 ranges between 150 and 350 feet in thickness. The underlying Devonian Beaverhill Lake argillaceous limestones form an irregular surface with structural or topographic relief of up to 175 feet per mile. Correlation of individual sand beds and lenses between test holes within the delta distributary deposits of the McMurray is difficult. Columnar stratigraphic section B-B' (Figure 16) illustrates the variability of deposition in this area. Gross correlations are possible, however, and the thicker sand units can usually be correlated for some distance.

The overburden is primarily Pleistocene glacial drift up to 100 feet or more in thickness and consists of fine, unconsolidated sand

and clay with occasional boulders and gravel. In some areas, a large proportion of the overburden is made up of barren silts and clays of the McMurray formation.

B. ACTIVITY

Shell Canada Limited initiated geological field studies along the Athabasca River in 1945. In 1952 Lease 13 was acquired as Bituminous Sands Permit 12. In 1953 - 1955, 50 exploratory holes were drilled on Permit 12 and in 1956 the permit was converted to lease. During the period from 1957 to 1962, a series of experimental programs was conducted in the western portion of the lease to develop technology for in-situ extraction of bitumen from the McMurray sands.

In 1971, 97 evaluation holes were drilled throughout the lease in a program intended to delineate indicated commercial size mineable tar sand orebodies and to investigate overburden and groundwater conditions. Fullhole cores were taken at 12 locations and the "Con-cor" drilling method was used in the majority of the remaining holes. This technique yields small diameter continuous core samples, good quality cuttings and uncontaminated samples of formation fluid. Upon completion of this program, the average drilling density in the indicated orebody area was four holes per square mile. An orebody located in the central portion of Lease 13 proved to be the most attractive for development of the initial mining project. In 1972, 25 delineation test holes were drilled and two dewatering pump tests were conducted. The current 1973 drilling program consists of 125 test holes, primarily for detailed mine development planning. As the current program will not be completed until later this year, our interpretation is based on data obtained to the end of 1972. Preliminary results of the 1973 program have not indicated any signficant changes in the orebody configuration.

C. OREBODY PARAMETERS

(1) Method of Evaluation

The applicants have used primarily the electric logging technique to evaluate the bitumen content of the tar sand on Lease 13. A correlation between electric logs and core analyses was developed from 12 holes cored in the 1971 drilling program plus 3 holes cored from a previous program. The majority of the wells have been logged with the Laterolog, while some of the earlier wells had only a Short Normal or a combination of Short Normal - Laterolog. The logging suite for the 1971-72 drilling programs consisted of Laterolog for bitumen content and gamma ray for clay indentification, augmented by the Con-cor drill cuttings information. The Formation Density Log for bulk density information was run on the cored wells only. Figure 1 is an example of a cored well with logs and core analysis.

The log evaluation concept implies that there is one relationship between bitumen content and resistivity, as long as formation water resistivity and porosity remain fairly constant. These conditons were found to exist within the orebody. On the basis of resistivity measurements of numerous samples of formation water recovered while Con-cor drilling, the average

formation water resistivity for the orebody was determined to be 5 ohmmetres. As discussed later, porosity is fairly constant at approximately 33 percent. The curve relating resistivity to bitumen content as a percent of total weight-calculated, i.e. calculated from core and log data, is illustrated in Figure 2. Bitumen content is measured from core as a percent of the dry weight, which is converted to a total weight value through knowledge of porosity gained from the Formation Density Log. The conversion chart is illustrated in Figure 3. This method generates a calculated total weight value that is more representative of the in-situ conditions, since the dry weight measurement is independent of porosity and water content derived from core. Therefore, any water gained through core expansion or lost through evaporation does not affect the dry weight measurement. Figure 4 illustrates a comparison of bitumen content of grade ore (material having bitumen content greater than 6 percent total weight) evaluated from logs, against that determined from core analyses, for the 1971 cored holes. Figure 5 is a similar comparison for total footage of grade ore. Both comparisons show good agreement.

(2) Core Handling Procedure

All cores taken during the program were cut with a 4-7/8 inch inside diameter bit in a 5 inch plastic liner. The core-filled liners were brought to the surface where they were capped immediately and frozen for later sampling and analysis.

Sampling was conducted by removing a thin slice, foot by foot, continuously from the centre of the frozen core. The complete one-foot slice sample was analyzed. In this manner, a representative sample was obtained and every portion of the core was analyzed, thereby providing more meaningful data for correlation. Figure 6 demonstrates how this sampling was carried out.

The one-foot slice sample was analyzed by the conventional Dean Stark toluene extraction method. Percent dry weight bitumen, which is defined as:

$$\frac{\text{Weight tar}}{\text{Weight dry sample}} \times 100\%$$

was the prime measurement. Percent total weight bitumen and apparent porosity, assuming 100 percent occupancy of pore space by the extracted water and bitumen, were also measured as a qualitative check.

(3) Bulk Density and Porosity

Based on the Formation Density Log interpretation, the bulk density and corresponding porosity of clean sand generally varies from 2.05 gms/cc (Ø = 36.0 %) to 2.15 gms/cc (Ø = 29.9 %) with a few values as low as 2.00 gms/cc (Ø = 39.0 %). Average bulk density of grade ore is 2.10 gms/cc (Ø = 32.9 %). Porosity values are based on a grain density of 2.64 gms/cc determined from laboratory measurements and 1.0 gms/cc for bitumen and water. Table A lists data summarizing the above information.

(4) Fines Determination

Fines are defined as those materials that pass through a Tyler 325 mesh sieve (44 microns). This parameter was evaluated from logs by correlating laboratory determined wet sieve fines content with the gamma ray response (Figure 7). Cross correlation with bitumen content is illustrated in Figure 8.

D. RESERVES

The orebody (Figure 9) as evaluated by the applicants contains 3,280 million barrels of recoverable bitumen out of a total of 3,720 million barrels in place, for a mining recovery of 88 percent. The unrecovered bitumen consists of 440 million barrels of uneconomic ore to be rejected or left in place during the mining operation.

Tables B and C list the pertinent mining parameters encountered in all test holes within the orebody areas drilled to the end of 1972. Table D lists these parameters for the remaining holes in the map area shown in Figure 9. The method of polygons* has been applied to calculate reserves and to determine the locations of the mining area, process plant and tailings ponds. The polygon method is based on the concept that all parameters determined for a certain point on an orebody, extend half the distance to adjoining and surrounding points. Polygons, which represent areas of equal influence, are constructed by the use of perpendicular bisectors on straight lines between the subject point of control and the surrounding points. The polygon is formed by the intersection of the bisector lines, with the number of sides of the polygon determined by the number of points of control in the surrounding area. The area of each polygon is determined by

* U.S. Bureau of Mines Information Circular No. 8283 (1966).

planimetering. The polygon base map with well control is shown on Figure 10. The applicants believe that because of the variability in ore grade and thickness, this method of evaluation is the least subjective.

In order to assimilate the most important parameters related to an economic mining operation, the applicants have developed a "quality factor" for each polygon. This factor is related to the amount of bitumen present in excess of the minimum volume that can be mined economically. Negative "quality factors" are those for areas that are not economically attractive. The quality factor assessment is illustrated in Figure 11. The algebraic definition of the quality factor is given on Table B.

The sequence of mining the orebody areas and the locations of the various supporting facilities are shown in Figure 9. Pertinent parameters relative to each of the areas are tabulated in Table E. The parameters influencing the decisions as to mining sequence, the location of the plant site and the supporting facilities, are illustrated on the accompanying polygon maps, as follows:

(1) Centre Reject means all material below the overburden and above the base of the orebody that is not mill feed.

(2) Waste/Ore Ratio (Figure 12) means the ratio of overburden plus centre reject to mill feed, to the base of the orebody.

(3) Overburden Thickness (Figure 13) means the thickness of all material above the top of the orebody.

(4) Mill Feed Grade (Figure 14) means the grade of any interval having an average bitumen content of greater than 6.0% total weight, over a thickness of 5 feet or greater.

Table F contains estimates of the unrecovered bitumen in pit walls and centre reject for each mining area, based on a projected pit slope of 60^0. This slope projection will be further refined by the test dragline program discussed in Section V Mining.

The areas between orebodies 1, 2 and 3 and orebody 4 are considered uneconomic to mine at the present time, due to high waste/ore ratio, low grade reserves, isolation or possible future river diversion. The applicants will continue to examine the reserve estimates in these areas through future drilling programs and final pit configuration design. The applicants will mine any part of this area if recovery of the reserves becomes economically viable. Table G presents additional analysis on the parameters that resulted in these areas being excluded from the proposed mining area.

The tailings ponds and the process plant are located in areas underlain by thick overburden and relatively low reserves with high waste/ore ratios that would be uneconomic to mine. The reserves that underlie these facilities are detailed in Table E. The applicants believe that their recovery would be technically feasible. The tailings could be removed by dredging and slurry pipelining prior to the use of mining equipment. The applicants will continue geologic and economic evaluation of the reserves under the tailings ponds, and will mine this area when recovery of the reserves becomes economically viable.

E. AQUIFER SANDS

Lease 13 groundwater occurs primarily in three main aquifer systems:

(1) a shallow aquifer in Pleistocene sands that comprise a portion of the overburden,

(2) intra-orebody aquifers within the McMurray, and

(3) a deep aquifer of barren sands at the base of the McMurray.

The relative positions of these aquifers in the orebody areas are illustrated in Sections A-A', B-B', and C-C' (Figures 15, 16, 17).

The problem of groundwater interference with mine operations has been studied in detail by groundwater geologists. The shallow aquifer exists, for the most part, under water table conditions; the intra-orebody and deep aquifers are under artesian conditions. To prevent seepage into the open pit, the shallow aquifer and the intra-orebody aquifers will be dewatered. In the deep aquifer, the artesian head will be lowered a few feet below the pit floor. The shallow aquifer in the orebody area consists of a glacial outwash of coarse clastics and clays with relatively low permeability. Air drilling through these deposits has indicated that water-influx is not great. A network of drainage ditches will be used to dewater this shallow aquifer. The isolated intra-orebody aquifers also constitute a minor source of water and will be dewatered by means of wells in conjunction with the depressuring of the deep aquifer.

A hydrological pumping test was conducted to determine the characteristics of the deep aquifer so that a mine dewatering system could be defined. A detailed description of the dewatering system is included in Section V (see page 21). The produced water will be contained in the tailings pond and fed to the extraction plant upon start-up.

A saline artesian aquifer occurs in the Methy carbonates, some 300 feet below the top of the Devonian. Test data from this reservoir indicate that it is a separate system from the deep sand aquifer and is not anticipated to be a problem during mining.

III TAR SAND CHARACTERISTICS

The applicants have carried out extensive research into the characteristics of the tar sand to ensure that Lease 13 material is amenable to processing by hot water extraction. These characteristics are as follows:

A. SIZE DISTRIBUTION

The major influencing factor in the efficiency of the hot water extraction process is the fines content of the tar sand feed. Size distribution of the various clays, silts and sands within the orebody have been determined by dry and wet sieve analyses as well as by visual inspections of cored materials.

Sieve analyses were conducted to develop a correlation between the fines fraction and the gamma ray logs as shown in Figure 7. Utilizing this correlation and the gamma ray logs, the fines content of the ore ranges from 5 percent in highly tar saturated sands to 30 percent in the low grade sands, the average being 14 percent. Table H is a typical well profile showing the gamma reading and the material size distribution.

The size distribution as typified by Figure 18 confirms our interpretation that Lease 13 is in a higher energy area of the deltaic deposition system and, as a result, the fines content is somewhat lower than in other leases.

B. FINES MINERALOGY

Associated with the fines is a considerable amount of colloidal clay and silica, which forms a stable suspension during the hot water extraction process and must be impounded at low solids concentrations in the tailings pond. The mineralogy of these fines is determined by separating the plus and minus 2 micron fractions and analyzing them with x-ray diffraction techniques. These fines consist mainly of silica, clay and trace amounts of feldspars and heavy minerals.

Analyses indicate that only 8 to 20 percent of the fines is minus 2 micron clay. Of this portion, only kaolinite, illite and trace amounts of chlorite and montmorillonite have been detected. The ratio of double layer silicates (kaolinite) to trilayer silicates (illite and chlorite) is about 4 to 1. This ratio is further evidence that the amount of montmorillonite or mixed layer clays that would form stable colloidal emulsion is low. The small amount of montmorillonite, and the existence of only the well crystallized clays in the Lease 13 orebody, indicate that the colloidal materials in the tailings pond should settle, thereby reducing the ultimate tailings pond requirements. Therefore, more pond water can be recycled and the overall fresh water requirement can be minimized.

Figure 8 represents the fines content of the tar sand as it is related to the bitumen grade. Based on Figure 8, a minimum cut-off grade of 6 percent has been selected, consistent with a fines content of 35 percent. However, as a fines content of 35 percent would be prohibitively high, the feed to the extraction plant will be blended to a minimum grade of 8 percent. The resulting fines content will be low enough for successful bitumen extraction.

C. BITUMEN

The average bitumen grade of the tar sand feed in the Lease 13 orebody is 11.5 weight percent.

The viscosity of bitumen from Lease 13 is 10 poises at 160°F, which is somewhat lower than the 50 poises measured in the Abasand area by the Alberta Research Council. This lower viscosity also ensures that the Lease 13 material will be amenable to the hot water extraction process.

D. WATER SATURATION

The tar sand deposits on Lease 13 underlie a highly developed glacial melt water channel system that is overlain by the Muskeg River. Water within the oil rich zones has been present since deposition of the McMurray formation in Lease 13, with the result that the tar sand in Lease 13 is water wet rather than oil wet. In locations where the water table has gone below the tar sand deposits in geological time, the tar sand is partially oil wet. It is known that the water wet nature of the tar sand is vital to the separation of bitumen from the solids.

In summary, the characteristics of the Lease 13 tar sand indicate that the material is amenable to the hot water extraction process.

IV OPERATIONS PLAN

The following description summarizes the operations used in each phase of the project, all of which are more particularly described in the sections that follow.

A. MINING

Four intermediate size (75 to 90 cubic yard) walking draglines will be used to remove the overburden and mine the tar sands. The ore will be cast onto piles, picked up by reclaimers and front end loaders, and conveyed to rail car loading stations.

B. ORE TRANSPORTATION

The ore will be transported from the mine to the extraction plant by locomotives hauling 100 ton side dump cars.

C. EXTRACTION

The K.A. Clark hot water extraction process will be used to effect the bitumen-mineral separation. Basic components of the process are tar sand conditioning, froth flotation, and naphtha dilution centrifuging.

D. DILUENT RECOVERY

The naphtha diluent and entrained water will be separated from the bitumen by conventional water flashing and hydrocarbon distillation.

E. PRIMARY SEPARATION

Vacuum flashing and solvent deasphalting will be used to remove the lighter portion of the bitumen. The remaining residue will be fed to the utility plant.

F. HYDROPROCESSING

The lighter oil removed from bitumen will be hydrotreated and hydrocracked to produce a low sulphur synthetic crude. Auxiliary units include hydrogen generation and sulphur removal.

G. TANKAGE AND PIPELINE

Sufficient tankage for operating flexibility will be provided on-site. The synthetic crude will be moved by pipeline to Edmonton.

H. UTILITIES PLANT

Steam and electric power will be supplied by the utilities plant. The utilities process configuration will maximize utilization of residue and minimize air pollution. These facilities will be described in detail in a future application pursuant to Section 7 of The Hydro and Electric Energy Act.

V MINING

A. INTRODUCTION

The mining method is a conventional open pit scheme that utilizes draglines for primary excavation, reclaimers and front end loaders for rehandling, and a locomotive-rail system for haulage. Figure 19 illustrates the mining scheme after three years of operation. The draglines are used to strip the overburden and excavate the tar sand; the reclaimers transfer the tar sand from the stockpile into rail cars by means of a conveyor; locomotives and rail cars transport the tar sand to the extraction plant.

The mining sequence, as defined by the orebody quality factors, is in the numerical order indicated in Figure 9. Detailed pit configurations and final pit limits will be the object of intensive short and long range mine planning. The final pit configuration will be designed for maximum recovery of tar sands consistent with safe slopes.

The total potentially recoverable reserves in the four areas outlined are sufficient to sustain the proposed 100,000 barrel per day project for about 65 years. As the anticipated life of the present scheme is 25 years, the additional reserves could be processed in a subsequent mining operation.

More detailed geologic and economic evaluation of the orebodies will be conducted, based on the 1973 and subsequent drilling programs and on the test dragline program. The sequence and boundaries given in Figure 9 are preliminary, and could change as a result of this evaluation. Figure 9 represents the best estimate of the outline of the orebodies that can be defined with the data now available.

Area 1, the initial mining area, contains reserves adequate for the first 20 years of operation. Prior to development of Area 2, it will be necessary to divert the Muskeg River.

B. EXCAVATION

Large electric walking draglines will perform both overburden removal, and primary excavation of the tar sand to the entire depth of recovery. The overburden will be side cast into the mined out area; the tar sand will be stockpiled on the highwall. Waste material within the orebody will be dug and side-cast into the mined out area.

The utilization of large draglines for excavation offers economic advantages in both initial capital investment and operating costs. Draglines have an appreciable overall advantage over other types of equipment for excavation of tar sand deposits, because of their versatility and flexibility. In addition, they are capable of sustaining production for a high percentage of the operating time.

The dragline overall operating availability is estimated to be 70 to 75 percent. This estimate is conservative compared to large North American coal stripping draglines, where the overall operating availability is 80 to 85 percent. The lower efficiency estimate used for excavation of the tar sand deposit makes an appropriate allowance for less favourable operating conditions such as cold winter weather.

Initial mining will require 4 draglines. An additional machine may be added later in the mine life when material movement increases due to lower grade ore and a higher stripping ratio. The dragline bucket capacities will vary from 75 to 90 cubic yards depending upon digging conditions. The boom length on each machine will be designed to permit digging depths of 200 to 240 feet.

Certain areas within the orebody, where the maximum depth of the mineable deposit exceeds the digging depth of the dragline, will be benched and/or scalped. Multiple faces will be worked to allow maximum flexibility and blending, as illustrated in Figure 19.

The applicants intend to open a test pit on Lease 13 with a 10 to 15 cubic yard dragline. This test will be used to define equipment performance, tar sand characteristics, slope stability and dewatering requirements. A separate application will be made for approval to conduct this test.

C. REHANDLING TAR SAND

The reclaimers will load the stockpiled tar sand onto a conveyor that will discharge through a loading station into rail cars. Front end loaders will handle large lumps and act as a standby for the reclaimers.

D. ORE HAULAGE

A rail haulage system will transport the tar sand to the extraction plant. This system was selected because of its low capital and operating costs, and its high availability. Rail layouts that incorporate maximum flexibility will be utilized. Multiple main line tracks will allow maximum availability since derails and breakdowns can be bypassed easily.

The rail system will include 10 locomotives, pulling fourteen 100 ton side dump cars. The rail system will be automated to the maximum safe practical limit.

After being loaded, the trains will proceed to dumping stations, which consist of two under-track hoppers. Two sets of tracks will pass over each hopper so as to allow two trains to dump simultaneously.

E. DEWATERING REQUIREMENTS

On Lease 13, groundwater occurs in the glacial deposits that overlie the tar sand, in the thin sands within the orebody and within the barren sands that lie below the orebody. The water in the glacial deposits can be removed by ditching; the water within the orebody will be removed by pumping; the artesian sands below the orebody will be depressurized by pumping from boreholes.

A hydrological pumping test was conducted on the deep aquifer to provide the basis for the estimate of dewatering requirements. Based on (1) an average aquifer thickness of 30 feet, (2) a required drawdown of about 175 feet, (3) a pit configuration that includes an 8,000 foot working face advancing 900 feet per year, and assuming reasonable hydraulic continuity, the dewatering requirement is estimated to be 25,000 to 50,000 barrels per day. This water will be pumped into the tailings pond prior to being recycled into the extraction plant. Figure 19 illustrates the location of boreholes for the dewatering system.

VI EXTRACTION

A. INTRODUCTION

The applicants propose to extract bitumen from the tar sand of Lease 13 using the K.A. Clark hot water extraction process with subsequent technological improvements. Fundamentally, the process utilizes hot water, caustic and steam to condition tar sand for gravity separation. Froth flotation and dilution centrifuging are used to provide a suitable upgrading plant feed stock.

The hot water process has been proven operable on a commercial scale by Great Canadian Oil Sands Limited. Bench scale pilot testing of Lease 13 tar sand has shown that this material is readily amenable to the hot water extraction process. The flowsheet in Figure 20 and the material balance in Table I are average annual flows for the applicants' scheme.

B. PROCESS DESCRIPTION

(1) Plant Feed Rate

The hot water extraction facility is designed to process about 200,000 tons per calendar day of tar sand averaging 11.5 percent bitumen. Associated with the tar sand is about 14 percent fines, of which 8 to 20 percent is colloidal clay containing only trace amounts of montmorillonite or mixed layer clays. Because of the low fines content, favourable fines mineralogy, and relatively low bitumen viscosity, an average hydrocarbon recovery of 90 percent is expected with a plant stream factor of 90 percent.

Diluted bitumen storage will compensate for fluctuations in extraction plant outturn caused by plant feed bitumen content variations.

(2) Extraction

(a) Conditioning

Tar sand is delivered to surge bins in the extraction plant by dual conveyors, and fed into parallel processing lines. Each line consists of a large diameter conditioning drum in which the tar sand is pulped at 180°F using make-up water, caustic, pond water and steam. Screens at the discharge end of the conditioning drum reject coarse stone and hard clay to the oversize system.

(b) Primary Separation

The screened pulp is then flooded with additional hot pond water and middlings to provide mobility to the slurry. The 180°F slurry is pumped to the primary separation cell, where the aerated bitumen froth is skimmed off the top and coarse sand tailings are raked out of the discharge ports at the base of the vessel. In order to control the fines build-up in the separation zone of the cell, a middlings stream, composed of silts and fines with entrained bitumen, is continually withdrawn.

(c) Secondary Separation

Some of the middlings stream is recycled into the conditioned pulp. The excess is passed to a secondary bitumen recovery unit that further agitates the slurry and separates the bitumen from the spent pulp by extensive aeration.

The spent pulp from the secondary unit is recombined with the tailings from the primary cell and pumped to the tailings pond.

(d) Froth Treatment

The bitumen from both the primary and secondary units is then heated and agitated to de-aerate this froth for further treatment in a centrifuging plant.

Dilution centrifuging will be employed to dehydrate and demineralize the froth to provide suitable feed stock for the upgrading plant. Although thermal dehydration appears more efficient from a hydrocarbon recovery point of view, the overall energy requirement is higher than that required for the centrifuging process.

Dilution centrifuging utilizes naphtha, a recycle material, as a diluent to reduce the specific gravity and viscosity of the bitumen, with the result that the entrained solids and water, which are heavier than diluted bitumen, can be segregated by gravity separation.

The diluted bitumen is centrifuged in the primary solid-liquid separator at relatively low gravitational forces to remove the larger mineral matter. The high energy secondary solid-liquid-liquid separator then removes further solid as well as water from the diluted bitumen. Diluted bitumen is stored in surge tanks ahead of the upgrading facility, and centrifuge wastes are transported to the tailings pond.

Further process optimization prior to and during start-up is expected to reduce the diluted bitumen loss substantially.

C. TAR SAND PROCESSING

Published work on the Alberta tar sands indicates that the processability of the tar sand in any commercial deposit can vary greatly. Testing has confirmed the applicants' conclusions that tar sand from Lease 13 is suitable for hot water extraction.

The coarser, well wetted material from Lease 13 is such that the bitumen will separate readily from the sands. Also, low bitumen viscosities will render the froth more pumpable, and should increase the solids removal efficiency.

As mentioned in a previous section, the mineralogy of the fines in the tar sand on Lease 13 is favourable. Thus the amount of fresh water that will be impounded with colloidal clays will be reduced, and more tailings water can be recycled. Also, this favourable mineralogy will result in low froth fines content, which will decrease the mineral load on the centrifuging plant.

D. WATER MANAGEMENT

(1) Fresh Water Requirements

The anticipated fresh water requirement is 0.21 tons of water per ton of tar sand feed. During the start-up period, an inventory of fresh water will be accumulated to permit recycle from the tailings pond, so that for the first year the total fresh water requirement could be as high as one ton of water per ton of tar sand feed. Table J shows the Athabasca River flow rate compared to extraction plant make-up water requirements. The normal plant use of 17.5 cubic feet per second will be small compared to overall river flows. These requirements from the Athabasca River will be further reduced by the use of surface and subsurface water from the lease. With fresh water requirements minimized and tailings pond recycle water maximized, the size of the tailings pond and associated environmental problems will be reduced.

(2) Tailings Disposal

Tailings leave the extraction facility in slurry form consisting of between 45 and 50 percent solids by weight. The tailings will be transported hydraulically to the pond area shown in Figure 9.

The starter dike will be built with material from within the pond area. The tailings pond will occupy an area of approximately five square miles and will be divided into two cells. One cell will contain coarse, rapid settling material while the other cell will contain fine, slow settling material. Once production has commenced, the coarse sands will be used to construct the dike either by spigotting or cycloning, and the sludge materials will be disposed of in the pond. The sludge, which is composed of clays, fine silts and small quantities of bitumen, will initially filter into the sand dike and, within a few days, will form an impervious barrier to seepage.

The upstream method of tailings dike construction will be used, allowing vegetation of the outer slopes soon after mining commences. It is expected that the tailings dike will be used for 8 to 10 years, after which tailings will be pumped directly into the mined out areas of the pit.

The use of two tailings ponds will allow materials of high clay content to be impounded separately. In a single pond system, all suspended colloids near the pond surface would be recycled causing further particulate dispersion. In a two pond system, the clay colloids will not be further dispersed by being recycled; therefore, the solids concentration in the pond can be maximized.

Clarified water from the tailings ponds will be decanted to a settling pond where the remaining solids can settle out. Water from this pond will then be recycled as make-up to the extraction plant.

The facility has been designed so that no effluent or overflow from these ponds will be discharged into the Athabasca River.

The clay mineralogy of tar sand in Lease 13 indicates that only trace amounts of montmorillonite or mixed layer clays exist in the area. The tailings should therefore concentrate more quickly than in areas where the clay problem is more severe.

The pond water balance is presented in Table K.

VII UPGRADING AND UTILITIES

The naphtha in the diluted bitumen is removed by distillation in the diluent recovery section. The bitumen is fed to the upgrading plant for conversion into a material that can be pipelined and used as a conventional refinery feed stock.

The upgrading scheme uses commercially proven processes. A process scheme has been chosen to yield a high recovery of synthetic crude and to produce very low sulphur emissions to the atmosphere. Figure 21 illustrates the upgrading processing sequence, which can be subdivided into five basic sections: primary separation, hydroprocessing, utility plant, sulphur recovery and tankage. An overall material balance is presented in Table L.

Table M shows the energy balance for the total project. Overall energy recovery in the synthetic crude from bitumen and natural gas input is 70 percent.

A. PRIMARY SEPARATION

Primary separation of the lighter components in bitumen is effected by (a) vacuum distillation of bitumen into vacuum gas oil and vacuum residue, and (b) light paraffin solvent deasphalting of the vacuum residue into deasphalted oil and deasphalter residue. The combination of these two physical separation steps maximizes the recovery of the lighter portion of the bitumen.

Bitumen extracted from tar sands is similar in boiling range to the residue obtained from atmospheric distillation of conventional crude oil.

Both have significant quantities of hydrocarbons that can be recovered through further distillation at vacuum conditions. Vacuum distillation allows separation of the lighter hydrocarbons at temperature levels below those at which coking would result. Maximum recovery of vacuum gas oil is desirable to reduce the size of the downstream deasphalter.

While not considered to be a serious problem, the effect of clay transport on primary separation equipment and downstream processing is being investigated.

B. HYDROPROCESSING

The lighter oil is upgraded to synthetic crude via hydroprocessing as follows: the vacuum gas oil is hydrotreated to remove sulphur, and to upgrade the oil to a catalytic cracker feedstock for conventional refining. The deasphalted oil, on the other hand, requires conversion to lighter distillates. Hydrocracking is used to achieve high conversion of the deasphalted oil to recoverable (1000^{o}F minus) distillates.

Hydrocracking is presently commercially practiced on hydrocarbon feedstocks ranging from 500^{o}F boiling point to heavy residual fractions. The refinery experience of the Shell group of companies in hydrocracking deasphalted oils is being applied as a basis for design of this facility.

Hydrogen demand for the hydrocracking process is considerably greater than that for hydrotreating. However, hydrocracking performs both conversion of the deasphalted oil to lighter distillates and hydrotreating for the removal of nitrogen and sulphur compounds. A major advantage of hydrocracking is that the products are suitable for direct blending into synthetic crude. The applicants will be carrying out extensive pilot evaluations on the hydrocracking process to further define process yields and economics.

The upgrading process will produce a synthetic crude yielding less than 5 percent residue in a conventional refinery operation. The synthetic crude will have the following properties:

Gravity	30^{o} API
Sulphur	0.4 wt % max.
Nitrogen	0.1 wt % max.
Volume off at $390^{o}F$	10%
Volume off at $1000^{o}F$	96%

Butane and lighter off-gases from the hydroprocessing units are amine treated for H_2S removal before being fed to the hydrogen plant. A small amount of natural gas (approximately 10 MMSCF/CD) will be required to supplement this stream, as dictated by the total hydrogen demand for the complex.

C. UTILITY PLANT

The utility plant will be the subject of a future submission to the Energy Resources Conservation Board. A basic description of this plant as now envisaged is as follows:

The deasphalter residue is first combusted with air at moderate pressures using steam as a reaction moderator, thus providing a reducing atmosphere for the reaction to occur. The resulting low BTU fuel gas is scrubbed for H_2S removal, and used in both the upgrading and utility plants. In the utility plant the gas is combusted and, after generating electrical power in a gas turbine, is sent to waste heat boilers to generate high pressure steam. This steam generates additional electricity through back pressure turbines. The resulting low pressure exhaust steam, supplemented by steam from the upgrading section, is used in the extraction plant.

The Shell group has considerable experience in design and operation of gasification facilities on feedstocks of the same boiling range as the deasphalted residue. Over 100 Shell designed reactors are presently in operation. A large scale pilot plant will be used for extensive process studies on feedstock from bitumen.

While the plant has been designed to be in energy balance, future detailed studies for the utilities plant application mentioned above will refine the energy balance, and may indicate a minor surplus or deficiency of electrical power. Engineering studies are in progress to confirm the overall technologic and economic viability of this process scheme.

Sour process water will be steam stripped to remove odorous compounds. Oily water from the upgrading units will be routed through an API separator for oil removal. All process effluent water streams and storm water will be diverted to the tailings pond, so that all such waters are impounded on the lease.

D. SULPHUR RECOVERY

Sulphur emissions are low because all the sulphur removed from the bitumen is converted to H_2S and scrubbed from vent gases. In addition, no high sulphur content residue is burned. The H_2S from the amine treater and the gasification plant scrubber is fed to a 3 stage Claus plant consisting of 2 independent trains. The applicants' experience in refinery operations, with H_2S streams having a high NH_3 content, indicates that a 95 percent sulphur plant efficiency can be attained. The overall upgrading/utilities sulphur balance is presented in Table N.

The tail gas from the sulphur plant will be combined with utility plant flue gas in a single 400 foot stack. Concentration of SO_2 in this stack is estimated at 1100 ppm. Because the upgrading plant process heaters are burning clean low BTU synthetic gas, their effluent will contain approximately 100 ppm SO_2. These individual stacks will make negligible contribution to the calculated maximum SO_2 ground level concentration of .06 ppm. The total sulphur emitted is 53 LT/CD. Guidelines on stack gas and ambient monitoring and plant sulphur balances, as prescribed in or pursuant to The Clean Air Act, will be followed.

Using the above equipment configuration, the existing standards for nitrogen oxides and particulate emissions will be met.

E. TANKAGE

Installation of 4.7 million barrels for feed, intermediate and product tankage will provide operating and finished product scheduling flexibility. This intermediate tankage will allow the independent shutdown of the extraction and upgrading plants for periods of up to 10 days.

VIII PIPELINE

Arrangements for movement of the synthetic crude from the plant site to Edmonton are under study. The applicants support the concept of an industry pipeline from the Fort McMurray area. This concept will be pursued with others involved in tar sand development, taking into account government policy that may evolve. In the event that suitable joint venture industry arrangements cannot be made, the applicants are prepared to construct their own pipeline facilities.

IX ENVIRONMENT

A. INTRODUCTION

The applicants share a nationwide concern for the protection of the environment, and intend to work closely with environmental authorities to achieve acceptable development plans. The applicants intend to follow a policy of keeping regulatory authorities and the public informed of their environmental activities, and of ensuring that their employees are aware of their environmental policies.

High priority is being assigned to environmental planning in all phases of the engineering design and development. The applicants look forward to establishing close working relationships with those governmental agencies charged with formulating and enforcing applicable legislation, and are confident they can contribute in a constructive and useful manner to the development of knowledge relating to the environmental impact of tar sands development.

B. ENVIRONMENTAL STUDY PROGRAM

As an integral part of their project planning, the applicants have initiated a comprehensive program to identify and study the biological environment, particularly as it will be influenced by the mining project. The first phase of this environmental study program has the following major objectives:

(1) to identify the baseline condition of the development area,

(2) to estimate the impact of the mining development on the environment,

(3) to consider land reclamation techniques applicable during and after the development, and

(4) to outline an ongoing study program to gather seasonal data up to and beyond the commencement of construction.

This first phase study is currently in progress. Some preliminary conclusions are presented below. Since this study is a first phase identification program, these conclusions are necessarily of a general and preliminary nature.

(1) Air Quality

Baseline air contaminant levels were sampled and were found to vary from nil to readily detectable levels, depending on wind direction and weather conditions.

(2) Surface Hydrology

The lease area is drained primarily by the Muskeg River and its tributaries. Peak Muskeg River flows appear to be associated with spring run-off. Stream capacity is about 1,000 cubic feet per second between banks. The 1973 spring peak flow was less than half of this value.

(3) Agriculture

Because of poor soils and the short growing season, the lease area has no current agricultural use, and little or no capability.

(4) <u>Vegetation</u>

The vegetation on Lease 13 is typical northern boreal forest with trees and shrub areas interspersed with wetland. About 32% of the lease is forested, 26% is muskeg, and 42% is scrubwood. Some stabilized sand dunes are demarked by vegetation patterns.

(5) <u>Forestry</u>

The forested areas are fire successional, following extensive burns in the nineteen fifties. Predominant species are trembling aspen, jack pine, and white and black spruce. Productivity of the area for commercial timber is estimated to be quite low. Only a few stands appear of sufficient size and quality to be of commercial value.

(6) <u>Wildlife Habitat</u>

The fire successional mixed wood character now evident appears to be the dominant factor in providing present habitat properties.

Waterfowl capability of the area is estimated to be marginal. Ungulate capacity (principally moose) is considered moderate to low. The more favourable areas are associated with the streams and wetlands on the lease area.

There are several fur-bearer traplines crossing the lease, and beaver are presently being taken by the trapline owners.

The fish supporting capability of the Muskeg River is estimated to be low and probably confined to coarse species on the lease area.

Some portions of the river downstream from the lease appear favourable to spawning use.

The applicants have conducted a spawning survey on the Muskeg River to initiate study of spawning use and fish passage through the lease area. The applicants hope to secure co-operation from other lessees to develop fishery habitat data on a wider scale.

(7) <u>Recreational - Historic Value</u>

Recreation capability of the area is now marginal, because of the predominance of muskeg and dense scrub, and lack of access. Archeological and historical sites have not been encountered on the lease area in preliminary surveys.

C. <u>FUTURE PROGRAM OF ENVIRONMENTAL STUDY</u>

The first phase of the environmental study program outlined above, and the accompanying interaction with government and industry, have led to the conclusion that accumulation of knowledge pertinent to virtually all potential environmental effects related to tar sands development is in its infancy. The applicants will be actively involved in contributing to knowledge in this area, both individually, and in co-operation with government and industry programs that are expected to evolve.

The program planned by the applicants will seek to reduce the impact of the mining development by proceeding with land reclamation planning coincident with the mining program.

Some general objectives that the applicants feel pertinent to these studies are:

(1) To return the land to a productivity that is at least as valuable as before disturbance. This may include enhanced recreation capabilities, or improved wildlife habitat over that presently encountered, or possibly reforestation with pulpwood species seedlings.

(2) To control deleterious effects on area watersheds, both surface and subsurface. This will be carried out within and, where technically and economically feasible, beyond the requirements of The Clean Water Act. One policy contributing to this objective will be the retention from area watersheds of all effluent waters.

(3) To control wind erosion on disturbed areas, by revegetating with native species where practicable.

(4) To minimize the visual impact of the development.

(5) To minimize airborne emissions within and, where technically and economically feasible, beyond the requirements of The Clean Air Act.

Specific areas that the applicant intends to investigate to contribute to these objectives are given in the list below. This list must be considered open ended, since the results of the research itself, plus evolving industry and government policy, dictate a need for flexibility in planning programs.

(1) Air Systems

Baseline measurements have quantified existing air qualities. Additional studies across a wider area are needed, particularly on adiabatic lapse rates and diffusion phenomena that can contribute to cold weather inversions.

(2) Hydrological Patterns and Capacities

Surface run-off, erosion and watershed characteristics require continued study to evaluate qualities and quantities. Subsurface water movement should be correlated with the influence of surface mines. Water quality and sediment loads will be examined.

(3) River Systems

Prior to any required stream diversion, river system studies will be conducted. Seasonal and sustained use of various waters by aquatic systems will be evaluated as a continuation of the present spawning study. Potential disturbances, both on-site and downstream, will be quantified.

(4) Wildlife Habitats

Continued study will be performed across multiple seasons to gain an understanding of wildlife use of areas to be disturbed. The relative significance of usage will be related to the uniqueness of the area, and to the alternate habitats available that could minimize disturbance to animal communities.

(5) Reclamation Methods

Some research has been carried out by government and industry on vegetation and dike bank stabilization methods. The applicants intend to support and participate in planning and research in this area.

The applicants believe that an industry-wide approach, in co-operation with government, offers the best solution to many of the above study areas. This is particularly true where physical phenomena relevant to the mining development, i.e. air systems, river patterns, wildlife and fish habitats, are not confined to one lease. The applicants have been active in seeking and obtaining co-operation in such programs from other industry members in the Athabasca area.

It should be noted that approximately two and one-half years of development of the project is planned prior to a final commitment to commence construction of the major facilities. During this time, the information required to assess the impact of development will be collected.

Extensive study into Lease 13 clay mineralogy has confirmed that the applicants should be able to minimize the magnitude of the tailings impoundment problems.

In the upgrading section, a process configuration has been chosen that will maximize recovery of the resource, with low sulphur emissions.

In the reclamation area, concepts of deliberately planned lakes, marshes, and other attractive features will be considered to provide a greater range of habitat diversity. Although well in the future, these

concepts could result in greatly enhanced recreational and wildlife values for the McMurray area over those presently encountered in its relatively undeveloped state.

In conclusion, the applicants submit that with proper environmental planning and research, they can contribute to the orderly and environmentally acceptable development of one of the province's most valuable natural resources.

X QUALIFICATION UNDER ALBERTA OIL SANDS POLICY

In October 1962, the Government of the Province of Alberta announced a policy for the development of the Alberta tar sands. With respect to applications for tar sand development, that policy provided as follows:

> "For such production from the oil sands as may be able to reach markets clearly beyond present or foreseeable reach of Alberta's conventional industry, there is no need to restrict the rate of production from the oil sands and, provided the development program meets with the approval of the Oil and Gas Conservation Board, the Government will authorize it.
>
> On the other hand, for such oil sands production as would be in competition with present or foreseeable markets for conventionally-produced Alberta crude oil, the impact on the conventional industry will be carefully considered. In this instance, the Government's judgment is that the best interests of the province will be served
>
> a) in the initial stages of oil sands development, by restricting production to some 5 per cent of the total demand for Alberta oil - i.e. at a level of the order of that recently approved for Great Canadian;
>
> b) as market growth enables the conventional industry to produce at a greater proportion of its productive capacity, by permitting increments in oil sands production as recommended by the Oil and Gas Conservation Board, and on a scale, and so timed, as to retain incentive for the continued growth of the conventional industry; and
>
> c) by relating the scale and timing of increments of oil sands production also to the life index of proven reserves of conventional oil allowing the index to decline gradually from present levels but ensuring that it does not drop below 12 to 13 years."

In February 1968 the Government issued a statement clarifying and amending certain aspects of the 1962 policy. The principal portions of the 1968 statement that affected the criteria under which

applications for development would be considered are excerpted below:

> "With respect to an application proposing the marketing of oil sands production in markets that are beyond reach of the conventional industry, the present policy is satisfactory and will be continued with such production being unrestricted so long as the development program meets the conservation and related requirements of the Oil and Gas Conservation Board.
>
> "With respect to an application proposing the marketing of oil sands production within reach of the conventional industry, but not in 'new' markets as defined later, the Government believes that, as at present, the application should be approved only when indicated to be desirable on the basis of the trend in the life-index of the conventional industry. However, the criterion of per cent utilization of productive capacity referred to in the present policy is no longer useful and will be discarded."
>
> "The Government believes that in order to encourage greater growth in the total crude oil market than would otherwise occur and thereby permit further oil sands development, the present policy requires amendment with respect to the treatment of applications that provide for marketing a product from oil sands 'within reach' of the conventional industry. Where it can be demonstrated that the applicant's marketing proposal would provide such additional growth by the development of a 'new' market the Government is prepared to authorize further production of oil sands product at volumes equal to 50 per cent of the new market. A 'new' market would be one not being served today; one over and above the normal growth in existing markets; and one representing a net increase in total market."
>
> "It is recognized that during the next few years it is particularly difficult to estimate market growth. In view of this the Government believes it desirable to establish specific limitations on the additional volume of oil sands production that would be approved under this amendment of the 1962 policy. Accordingly, the total volume of commercial oil sands production, including the presently authorized production, that will be permitted to enter new markets within reach of the conventional industry will be restricted to 150,000 barrels per day. Unless some wholly unforeseen set of circumstances should develop, this limit will remain in effect for five years. During this period the limit will be reviewed and, if conditions warrant, it may be increased for a succeeding period.

Past government tar sands policy was developed when markets for crude produced by Alberta's conventional industry were much less than the industry's potential capacity to produce. It was therefore necessary to attempt to encourage development of tar sands while avoiding actions that would jeopardize the economic viability of the conventional industry and its contribution to the Alberta economy. It is now generally recognized that during the foreseeable future, combined domestic and export markets for Canadian and Alberta crude oil will be greatly in excess of any resonable expectation of production capability.

With regard to domestic markets for Canadian crude (i.e. west of the National Oil Policy line) Schedule 1 (below) shows projected demand assuming an annual growth rate conservatively estimated at 5 percent. (Average annual growth in 1960-70 period was approximately 6 percent). No precise projection of export demand is possible because, although the U.S. no longer imposes any volume restriction on imports, Canadian sales to the U.S. will be in direct competition with imports into the U.S. from overseas. The actual level of exports will therefore depend on price considerations, as well as producibility and pipeline capacity. However, it is clear that total projected U.S. demand for oil imports in the foreseeable future (shown in Schedule 2 below) will be far in excess of the potential volume available from Canada, whatever the source of production.

Figure 22 illustrates this conclusion in graphical form. The supply forecast is based on Energy Resources Conservation Board data, showing that available supply is estimated at about 2,550 MB/D by 1978, including 260 MB/D of tar sands oil. Domestic demand is taken from Schedule 1 and is estimated for 1978 as 1,000 MB/D, leaving 1,550 MB/D available for export.

This export volume is a small proportion - less than 20% - of U.S. total import needs in 1978 (about 8,300 MB/D - interpolated from Schedule 2). Thus, there will be undoubtedly a ready market for Canadian oil in the U.S. so long as its price is competitive with overseas imports.

(a) Schedule 1. Forecast demand for Canadian crude and NGL's in domestic markets west of National Oil Policy line (MB/D):

1972	747
1975	865
1978	1,000
1980	1,100
1985	1,410

The above is based on a 5% annual growth rate.

(b) Schedule 2. Forecast demand for total oil imports (crude and products) into U.S. from all sources (MMB/D of crude equivalent):

	A	B	C	Mean
1975	7.4	8.5	6.4	7.4
1980	7.5	10.6	9.1	9.1
1985	8.7	13.5	13.3	11.8

Sources:

Forecast A: Case II of National Petroleum Council report "U.S. Energy Outlook", December 1972.

Forecast B: Case III of above report.

Forecast C: Department of Interior report "U.S. Energy through year 2000", December 1972.

Under these conditions, the Alberta conventional industry will be able to increase crude oil production to a maximum capacity consistent with good production practice and economic considerations. The downward trend of the life index of Alberta conventional crude oil depicted in Figure 23, will therefore continue. The combination of continually growing markets, and relatively limited reserve additions, has caused the life index to fall from a high of 34 years in 1966, to its current level of 17 years. Although the future rate of life index decline is uncertain, a continuation of the downward trend appears inevitable. In all probability, the life index of conventional reserves will have dropped to, or below, the 12 to 13 years stipulated in government policy, before the project comes on stream. Life index would now appear to be a critical criterion governing approval of tar sands projects, and the applicants submit that approval of this application is justified under that criterion.

Both Shell Canada Limited and Shell Oil Company, the parent corporation of Shell Explorer Limited, are large integrated companies that purchase crude in order to augment the volumes available for their refining requirements from their own production; they also make sales of crude when necessary for logistic reasons. Bearing in mind the industry supply/demand projections for Canadian oil outlined above, production from this project will therefore be accommodated readily within the applicants' own requirements or traded out as appropriate.

XI ECONOMICS

A. INTRODUCTION

The following economic analyses present the applicants' estimates of all project capital and operating costs, including a calculation of the average annual rate of return on investment anticipated for the project.

While the applicants believe that these analyses represent a resonable projection of the project economics, some areas of uncertainty should be mentioned. Firstly, pending enunciation of Government policy or direction on the subject, a royalty rate on bitumen has been assumed. Secondly, although the cost estimates are based on the best information available, they will change with further engineering studies and detailed design. Lastly, given the present inflationary period, it is apparent that both synthetic crude prices and costs will escalate with time. Although previous trends can be of some value in projecting future costs in these areas, the same cannot be said for synthetic crude prices, which are sensitive to unpredictable factors such as major new discoveries, competition from alternative fuel sources, changes in trading patterns, and national and international political influences. One can postulate, however, that in a period of high demand for energy, it is reasonable that synthetic crude prices should rise more rapidly than costs. In fact, synthetic crude prices must escalate faster than capital and operating costs if this and other tar sands projects are to become viable.

B. DEVELOPMENT SCHEDULE

As shown in Figure 24, the applicants will carry out detailed evaluation and design of the project during the period 1973 through 1975. Construction is expected to commence in 1976 and first production is expected in early 1980. Because of the operational problems inherent in the start-up of such a complex facility, it has been assumed that peak production would not be reached until 1982.

C. ECONOMIC PARAMETERS

(1) Project Life

The economics are based on a facility producing 100,000 barrels per day of synthetic crude for 25 years.

(2) Products and Prices

Two saleable products, a 30° API synthetic crude and elemental sulphur, are produced. A price of $3.50 per barrel has been used as the approximate 1973 value of synthetic crude at Fort McMurray. No net income has been assumed from the sale of sulphur.

(3) Royalty

Pending enunciation of Government policy with respect to the form and magnitude of royalty that might be levied against future tar sand mining projects, a royalty rate of 16 2/3 percent of the value of the bitumen has been used. The value of the bitumen has been taken as 28 percent of the value of the posted price at Edmonton of 38° API conventional crude, as suggested in the

Canadian Petroleum Association's submission* of December 15, 1972 to the Government of Alberta.

(4) Operating Costs

The initial operating costs for the project, expressed in 1973 dollars, are estimated to be $41 million per year, including overhead and municipal taxes, but excluding Crown royalty, interest, income taxes and depreciation. Because of the variability in the overburden thickness and ore grade, the operating costs will vary from year to year, but on average will amount to about $48 million per year for the life of the project.

(5) Capital Costs

Based on preliminary engineering design estimates, pre-production expenditure requirements expressed in 1973 dollars will be $680 million, excluding the costs of townsite and access to the area. The individual components of this cost estimate are as follows:

	$ MM
Mining and Materials Handling	160
Extraction	65
Bitumen Upgrading	175
Utilities	140
Offsites and Miscellaneous	80
Start-up and Working Capital	30
Construction Camp	30
	$680

"In the Matter of Royalty to be Applied to Oil Sands", December 15, 1972.

In addition to the above expenditures, about $30 million will be spent in predevelopment mining expense to cover civil works and dike construction. The total will be spent according to the schedule shown below.

	$ MM
1974	10
1975	10
1976	55
1977	115
1978	175
1979	230
1980	115
	$710

Additional expenditures for extension of the mining transportation system and for equipment replacement will amount to $3 million per year.

Expenditures of some $14 million, which the applicants will have made prior to 1974 toward the development of this project, have not been included in the economic analysis.

(6) Escalation

While all economic parameters are shown in 1973 dollars, inflation and other economic factors will cause product prices and costs to escalate with time. To gain some insight into potential escalation, operating cost was divided into its component parts (e.g. labor, chemicals, and other materials).

The 10 year historical average escalation for each component was determined, and a calculation was made of a weighted composite escalation factor based on the fractional cost that each component bears to the total cost. Capital cost escalations were analyzed in a similar manner. On these bases, capital and operating costs are estimated to escalate at 5 percent and 4 percent per year, respectively.

In the absence of any long term historical data that were considered to be representative of future trends, the price of synthetic crude was assumed to escalate at 5 percent per year. While this rate is somewhat subjective, it is based on the view that in a period of high demand for energy, anticipated over the next several years, the price of fossil fuels will escalate more rapidly than the attendant costs of production. Both price and cost escalations have been applied from 1973 through the life of the project.

D. CONCLUSIONS

Table O presents the project economics, based on both 1973 costs and product prices, and on the escalated values discussed above.

The applicants believe that two significant conclusions may be drawn from this table:

(1) The return on project investment based on the assumed royalty and on 1973 costs and revenues, is clearly not acceptable, particularly when the high risks and capital exposure are considered.

(2) The escalated case demonstrates that for this project to become economically attractive, the price of synthetic crude must enjoy a substantial and continued rise and must stay ahead of cost inflation. Moreover, the profit potential must be high enough to accommodate the considerable downside risk that attends the technology and the projection of future economic factors.

XII FINANCING

The applicants are confident that their combined financial strength will ensure their ability to finance the project. It is expected this would be done by the combination of established internal cash generation together with debt, the latter to take the form of mortgage bonds or debentures as appropriate. Shell Oil Company will provide the financing to its subsidiary, Shell Explorer Limited.

The applicants are aware of the interest of the Government of Alberta in providing an opportunity for residents of Alberta to invest in projects of this nature, and intend to provide a means of accommodating this interest.

It will be clear, of course, that a venture of the character contemplated must be assured of a return commensurate with the risk, bearing in mind the size of the investment. These will be significant factors in the assessment by potential investors of the viability of the project and the extent to which they are prepared to support it.

Shell Canada Limited and Shell Oil Company have excellent standing in North American capital markets and over the years have successfully raised very large amounts of capital, both debt and equity, in these markets.

The financial condition of Shell Canada Limited and Shell Oil Company, respectively, for the past five years, together with the financial ratios that are used to measure the borrowing capacity of corporations, are set forth below.

Copies of the applicants' 1972 Annual Reports are enclosed.

NOTES TO STATEMENT OF FINANCIAL CONDITION OF SHELL CANADA LIMITED

1. INCOME TAXES

Shell Canada Limited and its subsidiaries follow the practice of claiming maximum capital cost allowances and similar deductions in calculating income for tax purposes.

The Canadian Institute of Chartered Accountants has recommended that for financial years commencing after December 31, 1967 the tax allocation basis of accounting for income taxes be followed. On this basis a deferred income tax provision would be recorded for the imputed tax effect of capital cost allowances and drilling and lease acquistion costs claimed for tax purposes in excess of depreciation, amortization and depletion charged against reported income. In the Canadian petroleum industry, an alternative method of recording deferred income taxes excludes provisions for the imputed tax effect of drilling and lease acquisition costs claimed in excess of amortization and depletion. Shell Canada has not recorded any deferred income taxes in its accounts because, in the opinion of management, such potential income taxes are not expected to materialize in the foreseeable future.

The imputed tax effect cumulatively to December 31, 1967 would have amounted to $29,000,000 for excess capital cost allowances and to approximately $24,000,000 for excess drilling and lease acquisition costs, for a total of approximately $53,000,000. Since December 31, 1967 the cumulative amount would have been approximately $41,000,000 and $8,000,000, respectively, for a total of approximately $49,000.000.

2. FINANCIAL RATIOS - DEFINITIONS

Working Capital Ratio
- Current assets divided by current liabilities.

Times Interest Earned (Before Tax) on Long Term Debt
- Net income plus interest on long term debt plus income taxes divided by interest on long term debt.

Working Capital Per $1 of Long Term Debt
- Working capital divided by long term debt.

Net Income (After Tax) Per $1 of Long Term Debt
- Net income divided by long term debt.

Cash Income Per $1 of Long Term Debt
- Funds provided from operations divided by long term debt.

SHELL CANADA LIMITED

$M

DECEMBER 31	1972	%	1971	%	1970	%	1969	%	1968
CAPITAL EMPLOYED									
Debt									
Long Term Debt	104,781	11.4	109,915	12.6	114,922	13.8	111,843	14.3	35,037
Deferred Revenue	5,612	0.6	6,571	0.8	6,571	0.8	-	-	-
	110,393	12.0	116,486	13.4	121,493	14.6	111,843	14.3	35,037
Equity									
Preference Shares	1,000	0.1	1,000	0.1	1,000	0.1	1,000	0.1	1,000
Common Shares	212,737	23.0	212,441	24.3	211,709	25.4	211,604	26.8	211,395
Retained Earnings	598,858	64.9	543,205	62.2	498,332	59.9	463,787	58.8	433,328
	812,595	88.0	756,646	86.6	711,041	85.4	676,391	85.7	645,723
TOTAL	922,988	100.0	873,132	100.0	832,534	100.0	788,234	100.0	680,760
Net Income	78,997		61,543		51,209		47,121		53,952
Funds Provided from Operations	128,941		105,517		99,521		94,512		101,961
Interest on Long Term Debt	6,953		7,317		7,566		6,256		1,953
Income Taxes	30,500		32,000		16,000				
Current Assets	345,529		310,992		289,446		263,916		219,381
Current Liabilities	134,736		130,111		125,455		104,712		120,975
Working Capital	210,793		180,881		163,991		159,204		98,406
FINANCIAL RATIOS									
Working Capital Ratio	2.56		2.39		2.31		2.52		1.81
Times Interest Earned (before tax) on Long Term Debt	16.75		13.78		9.88		8.53		28.63
Working Capital per $1 of Long Term Debt	$1.91		$1.55		$1.35		$1.42		$2.81
Net Income (after tax) per $1 of Long Term Debt	$0.71		$0.53		$0.42		$0.42		$1.54
Cash Income per $1 of Long Term Debt	$1.17		$0.91		$0.82		$0.85		$2.91
Net Tangible Assets per $1 of Long Term Debt	$7.92		$7.09		$6.46		$6.63		$18.11
Market Value of Common Stock per $1 of Long Term Debt (year end price)	$18.17 ($60-1/4)		$10.43 ($36-1/2)		$9.20 ($33-5/8)		$8.10 ($27-1/4)		$27.75 ($29-1/4)

* See notes following.

SHELL OIL COMPANY

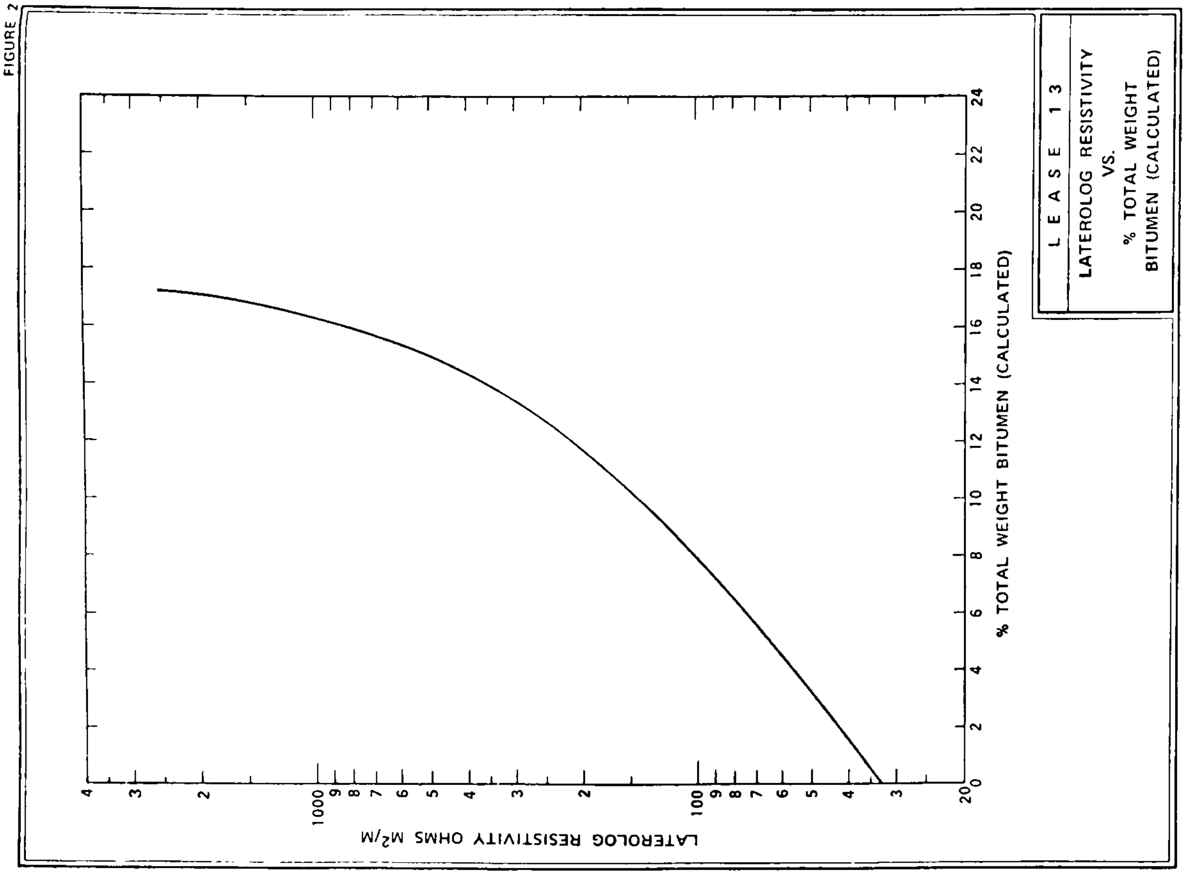
$M

DECEMBER 31	1972	%	1971	%	1970	%	1969	%	1968	%
CAPITAL EMPLOYED										
Long Term Debt	1,025,569	24.2	836,783	21.2	836,750	21.7	711,508	19.6	713,241	20.5
Deferred Taxes	292,892	6.9	281,560	7.1	274,415	7.1	252,502	7.0	221,766	6.4
Equity										
Common Shares	234,130	5.5	234,124	5.9	234,117	6.1	234,112	6.4	234,056	6.7
Retained Earnings	2,690,838	63.4	2,591,879	65.8	2,508,858	65.1	2,433,458	67.0	2,303,889	66.4
	2,924,068	68.9	2,826,003	71.7	2,742,975	71.2	2,667,570	73.4	2,537,945	73.1
TOTAL	4,243,429	100.0	3,944,346	100.0	3,854,140	100.0	3,631,580	100.0	3,472,952	100.0
Net Income	260,480		244,504		237,205		291,151		312,091	
Funds Provided From Operations	668,617		662,184		628,525		673,718		639,346	
Interest & Discount Amortization on Indebtedness	59,423		47,986		40,090		34,740		34,384	
Income Taxes	82,578		61,604		71,284		68,948		74,504	
Current Assets	1,596,095		1,234,414		1,232,619		1,255,089		1,403,179	
Current Liabilities	928,171		701,936		755,623		724,642		757,044	
Working Capital	667,924		532,478		476,996		530,447		646,135	
FINANCIAL RATIOS										
Working Capital Ratio	1.72		1.76		1.96		1.86		2.19	
Times Interest Earned (before tax) on long term debt	6.78		7.38		8.69		11.38		12.24	
Working Capital per $1 of long term debt	$0.65		$0.64		$0.57		$0.75		$0.91	
Net Income (after tax) per $1 of long term debt	$0.25		$0.29		$0.28		$0.41		$0.44	
Cash Income per $1 of Long term debt	$0.65		$0.79		$0.75		$0.95		$0.90	
Net Tangible Assets per $1 of long term debt	$4.00		$4.55		$4.46		$5.01		$4.80	
Market Value of Common Stock per $1 of long term debt (year end price) 58	$3.61 ($54-7/8)		$3.81 ($47-1/4)		$3.82 ($47-3/8)		$4.20 ($44-1/4)		$6.68 ($70-5/8)	

57 Net Tangible Assets Per $1 of Long Term Debt
- Working capital plus property, plant and equipment (net) divided by long term debt.

Market Value of Common Stock Per $1 of Long Term Debt
- Common shares outstanding times market value at December 31 divided by long term debt.

FIGURE 2



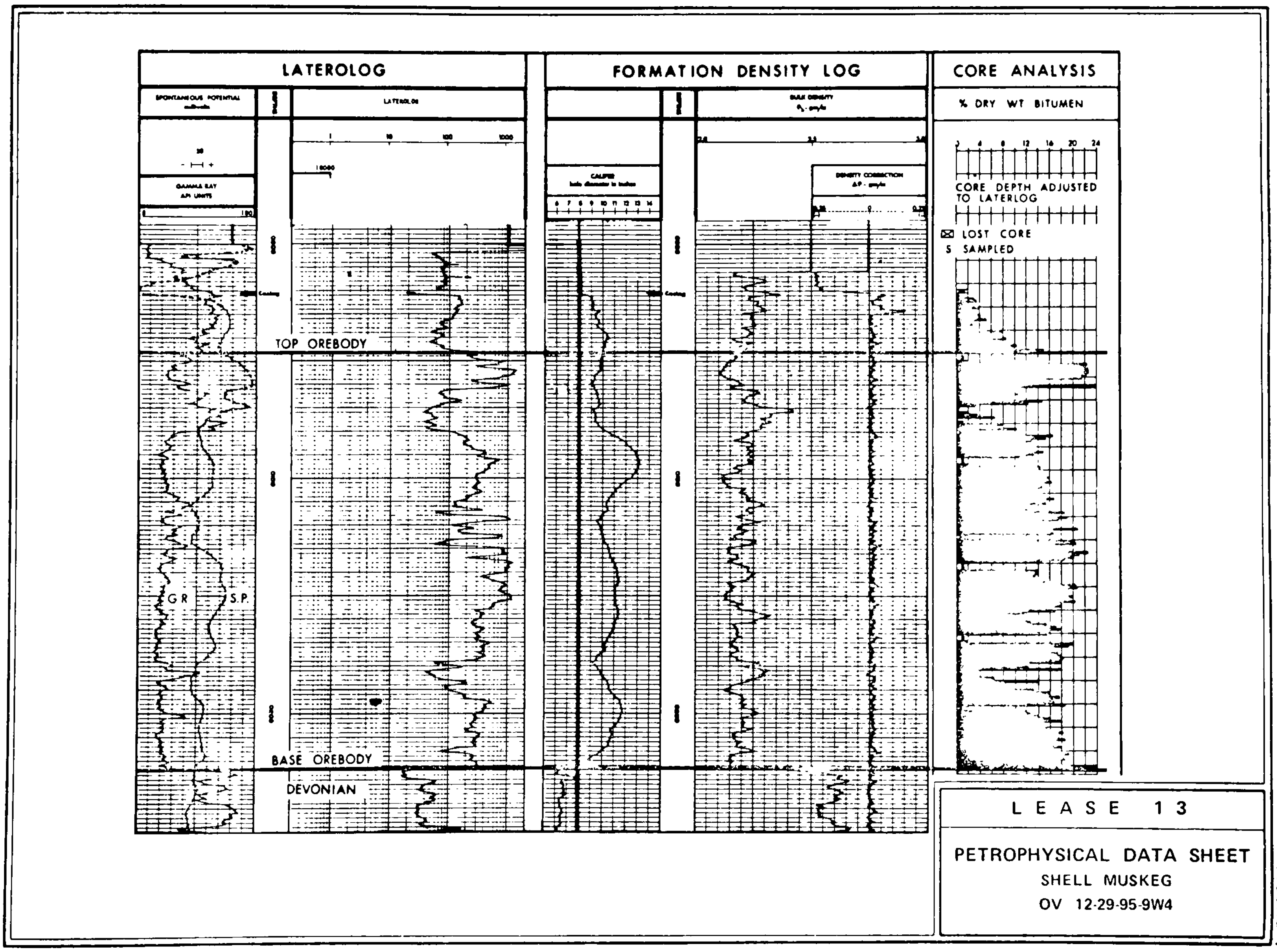


FIGURE 1

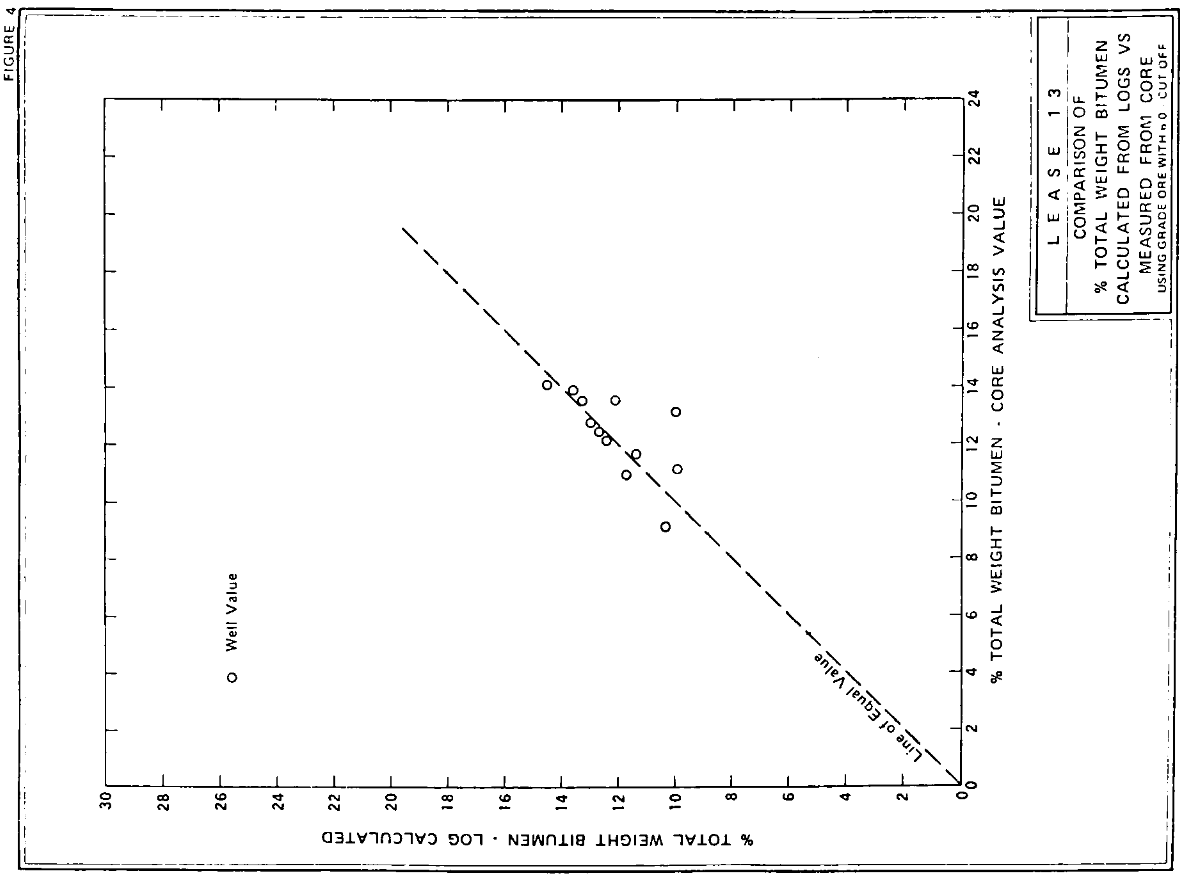


FIGURE 4
LEASE 13
COMPARISON OF
% TOTAL WEIGHT BITUMEN
CALCULATED FROM LOGS VS
MEASURED FROM CORE
% TOTAL WEIGHT BITUMEN - CORE ANALYSIS VALUE
% TOTAL WEIGHT BITUMEN - LOG CALCULATED
Well Value
Line of Equal Value

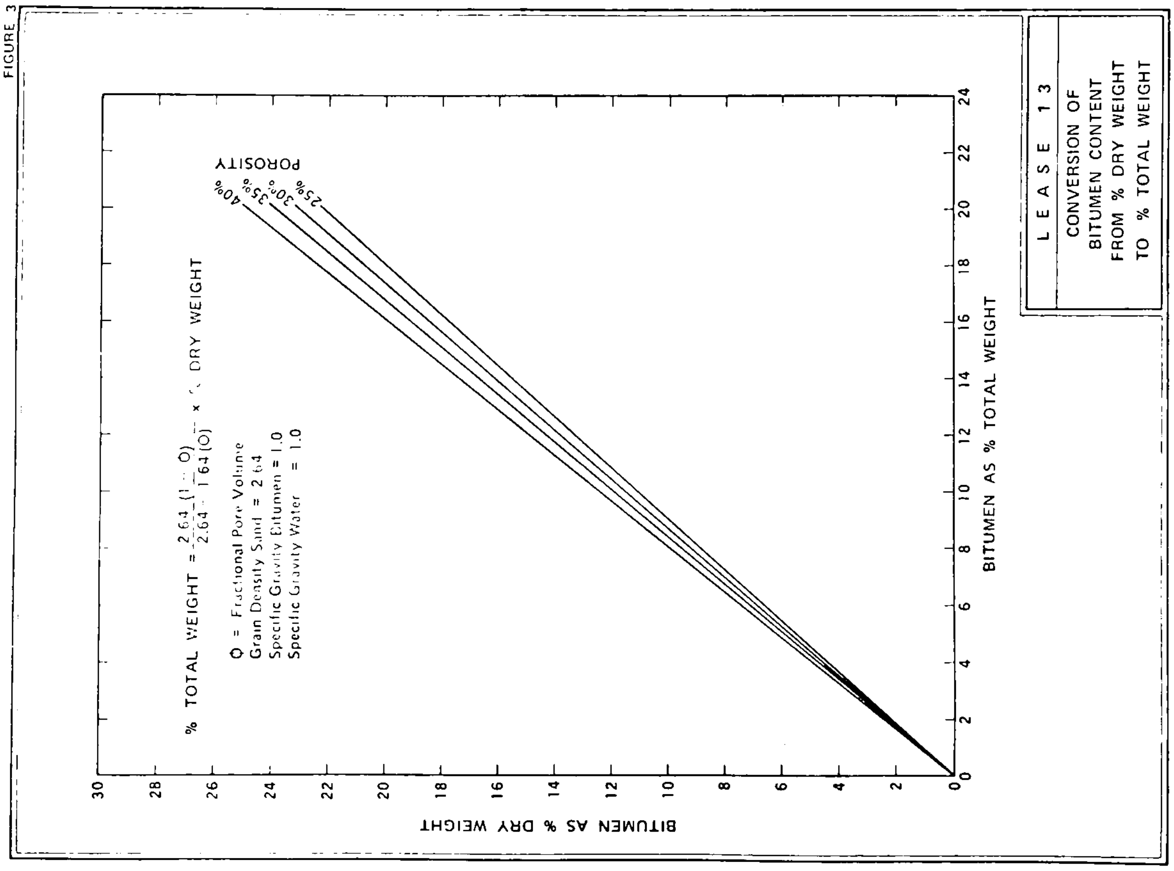


FIGURE 3
LEASE 13
CONVERSION OF
BITUMEN CONTENT
FROM % DRY WEIGHT
TO % TOTAL WEIGHT
BITUMEN AS % TOTAL WEIGHT
BITUMEN AS % DRY WEIGHT
POROSITY
40%
35%
30%
25%
Grain Density Sand = 2.64
Specific Gravity Bitumen = 1.0
Specific Gravity Water = 1.0

FIGURE 6

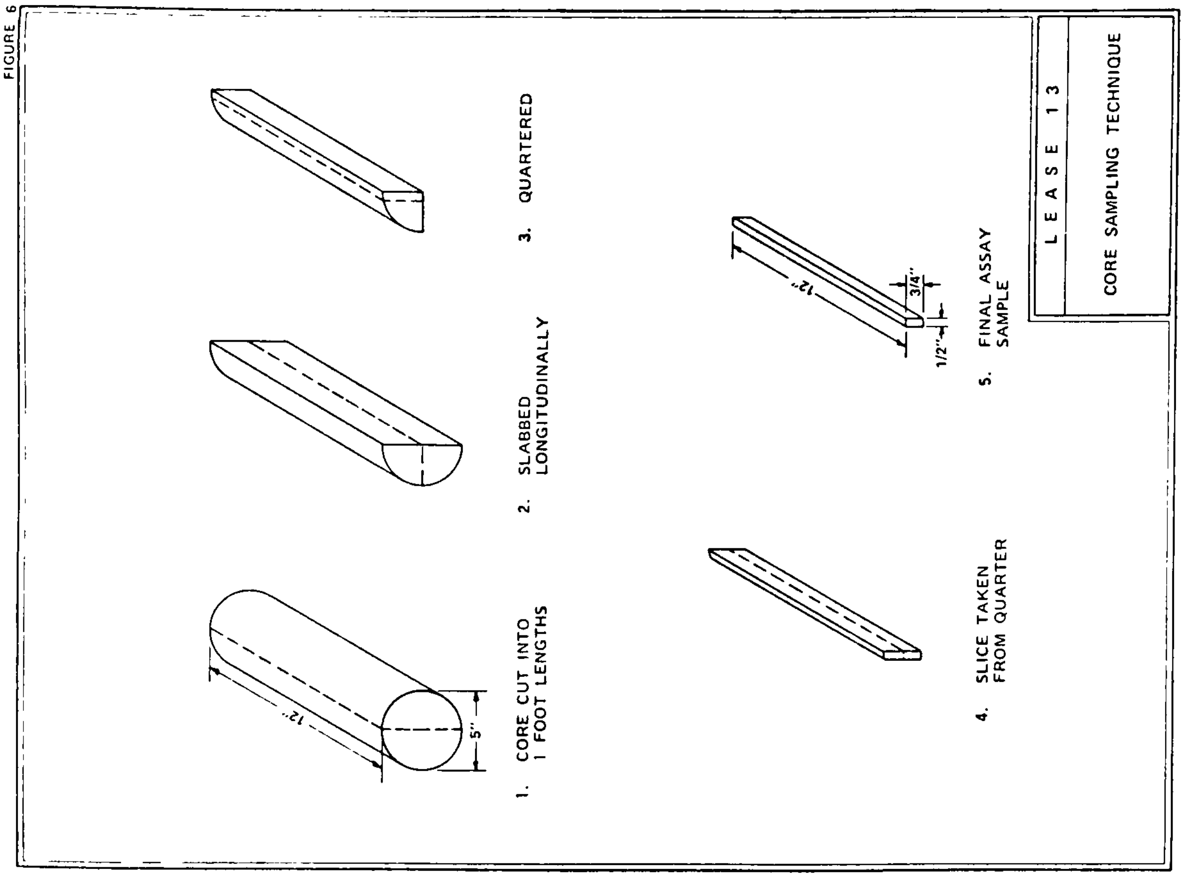
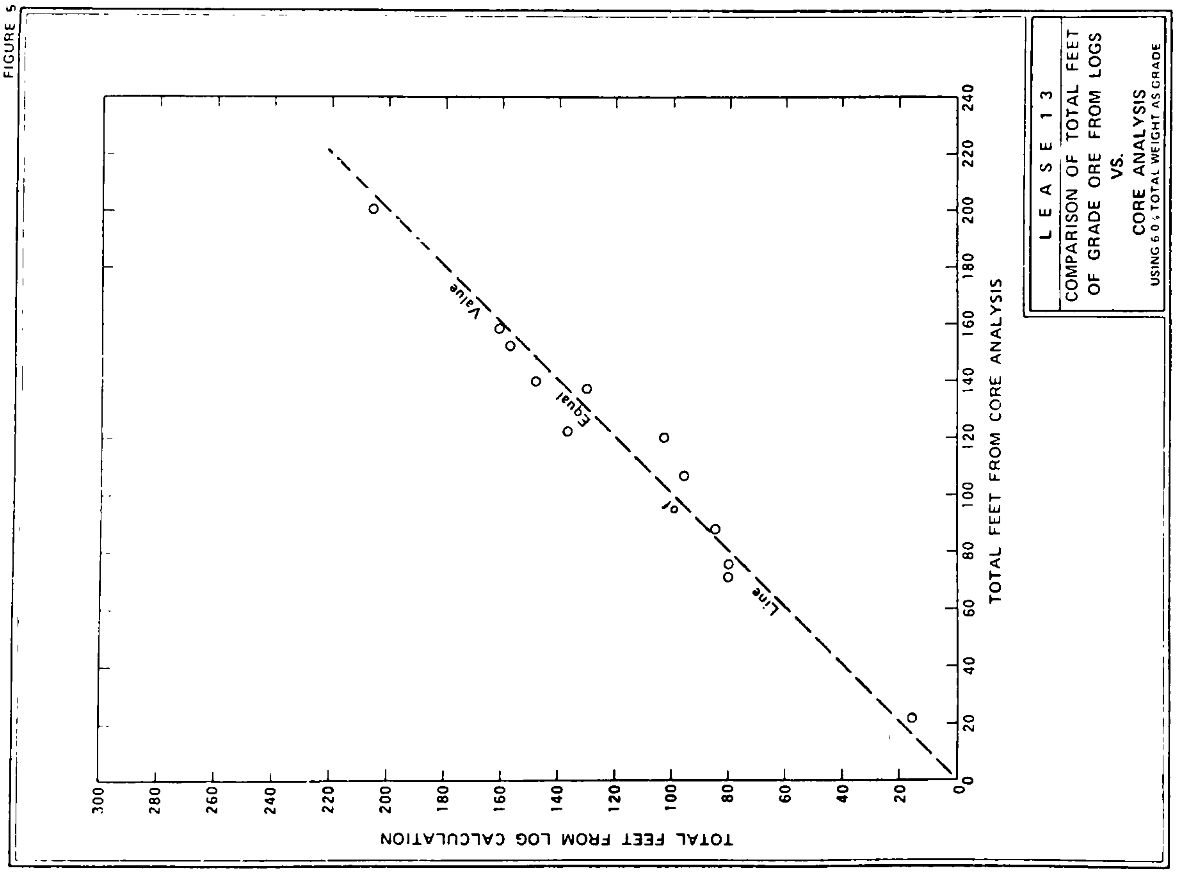


FIGURE 5



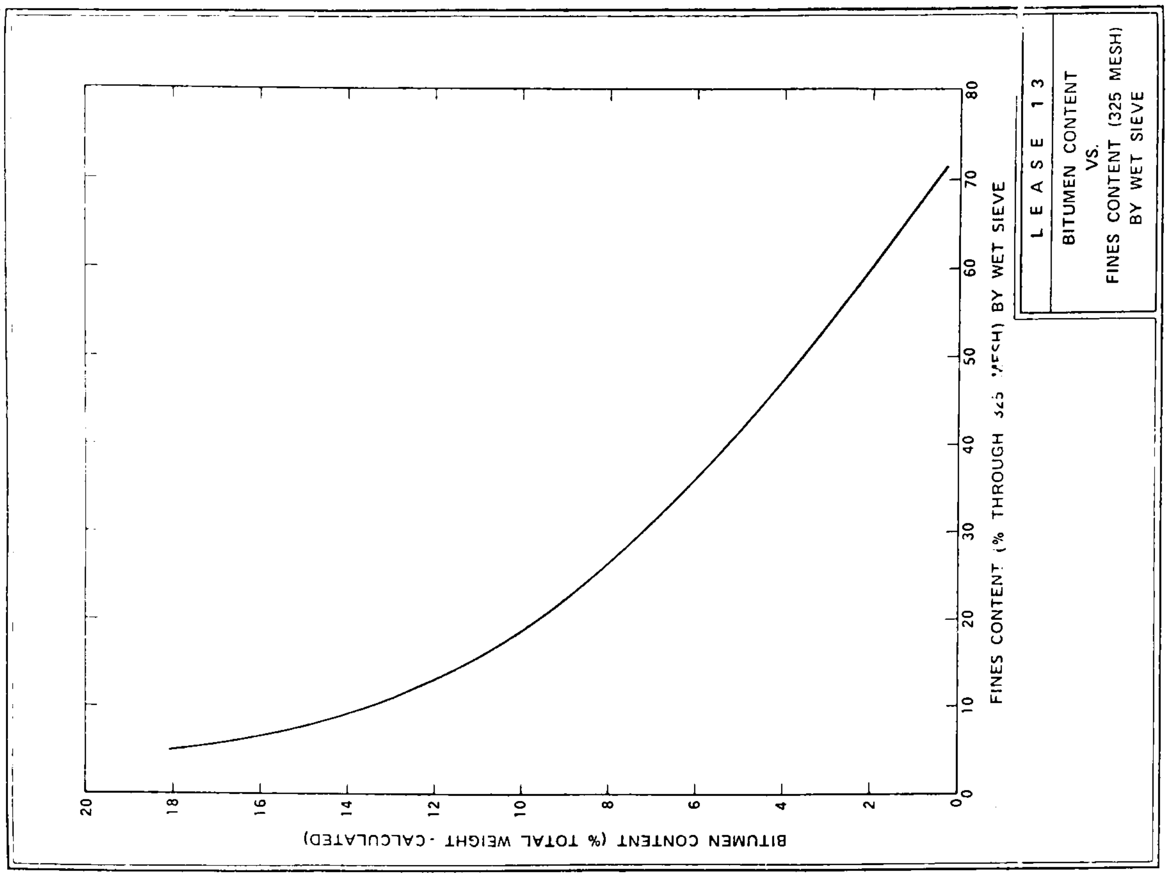
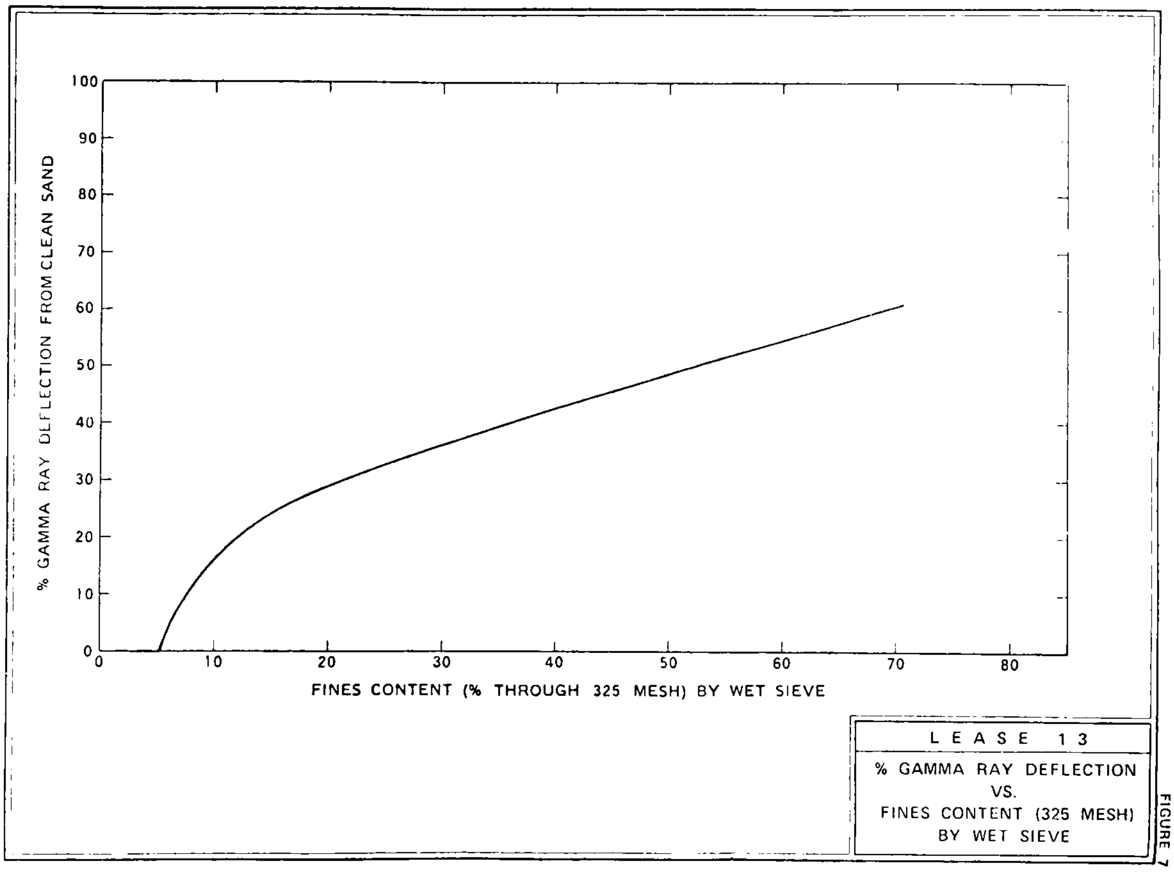


FIGURE 8
LEASE 13
BITUMEN CONTENT
VS.
FINES CONTENT (325 MESH)
BY WET SIEVE
FINES CONTENT (% THROUGH 325 MESH) BY WET SIEVE
BITUMEN CONTENT (% TOTAL WEIGHT - CALCULATED)
0
10
20
30
40
50
60
70
80
0
2
4
6
8
10
12
14
16
18
20


% GAMMA RAY DEFLECTION FROM CLEAN SAND
0
10
20
30
40
50
60
70
80
90
100
FINES CONTENT (% THROUGH 325 MESH) BY WET SIEVE
LEASE 13
% GAMMA RAY DEFLECTION
VS.
FINES CONTENT (325 MESH)
BY WET SIEVE
FIGURE 7

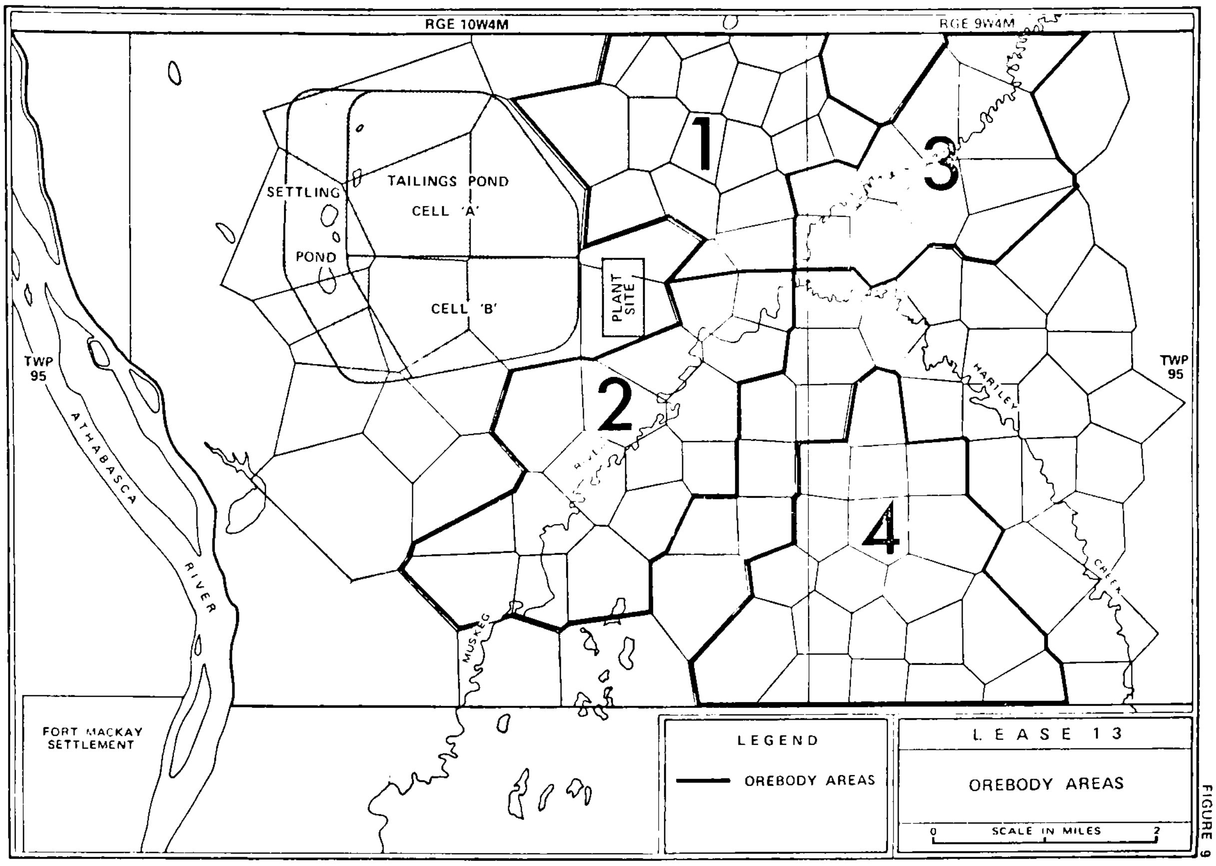


FIGURE 9

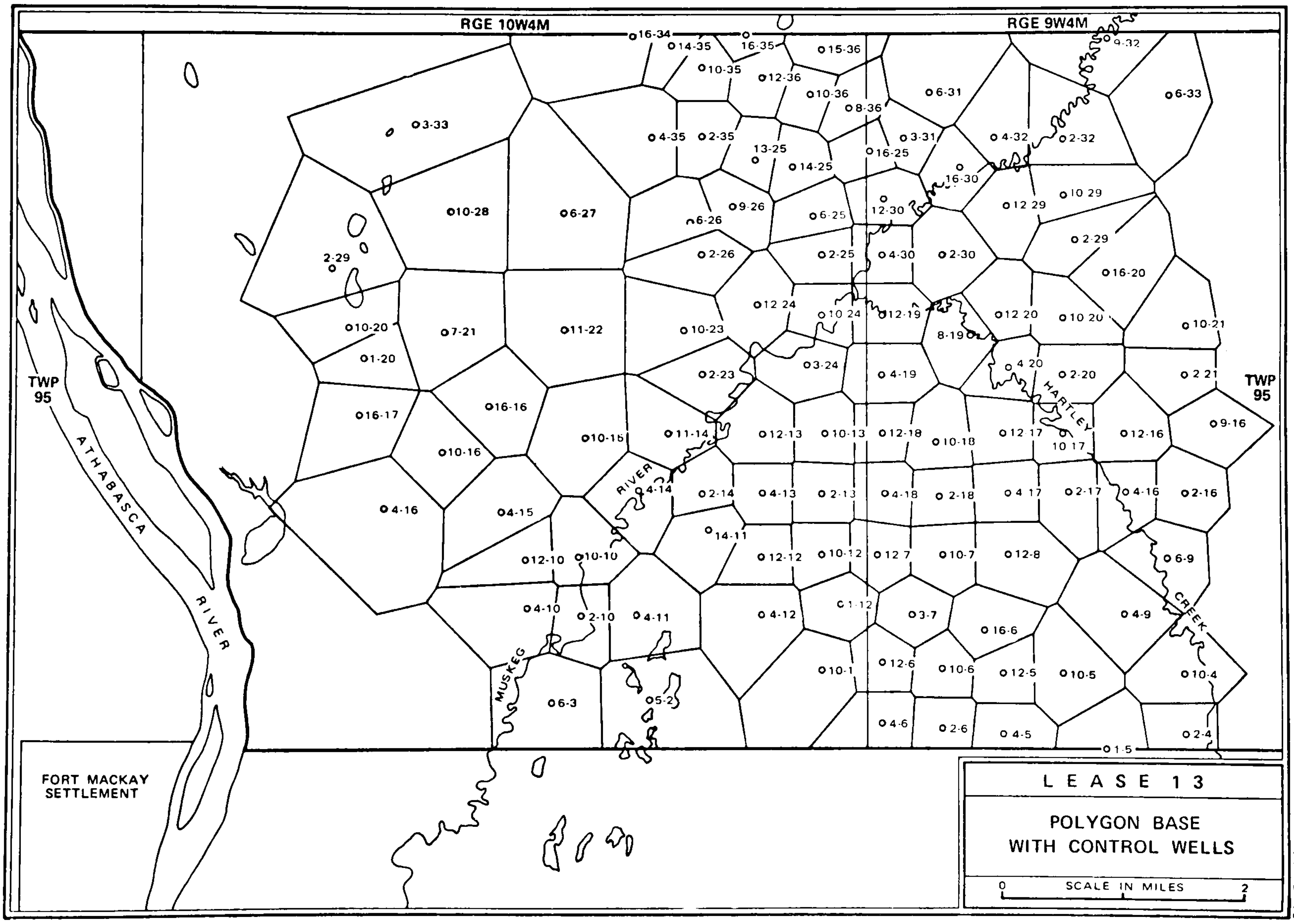


FIGURE 10

FIGURE 11

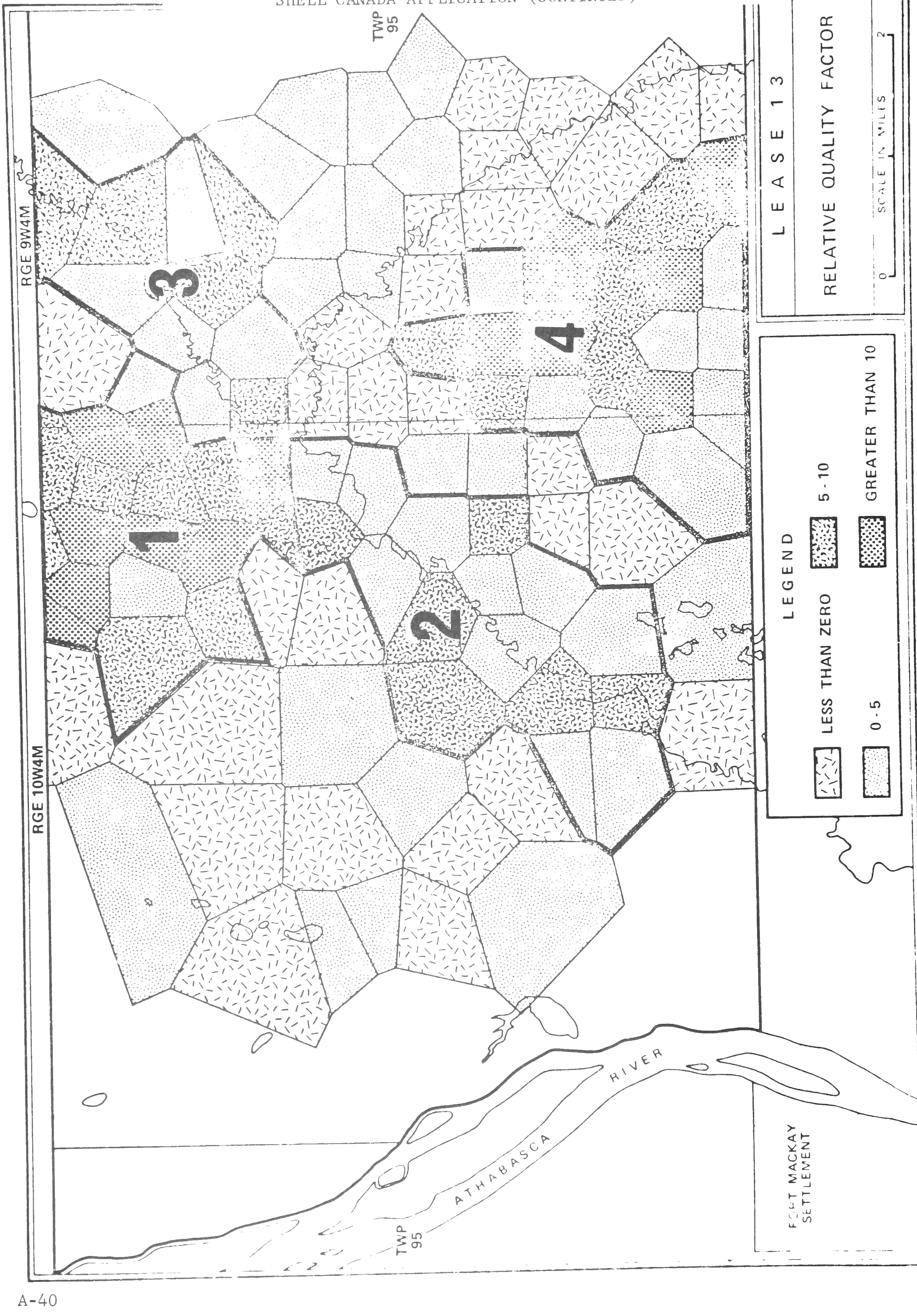

LEASE 13
RELATIVE QUALITY FACTOR
SCALE IN MILES
0
2
LEGEND
LESS THAN ZERO
0-5
5-10
GREATER THAN 10
RGE 9W4M
RGE 10W4M
TWP 95
TWP 95
1
2
3
4
ATHABASCA RIVER
FORT MACKAY SETTLEMENT

FIGURE 12

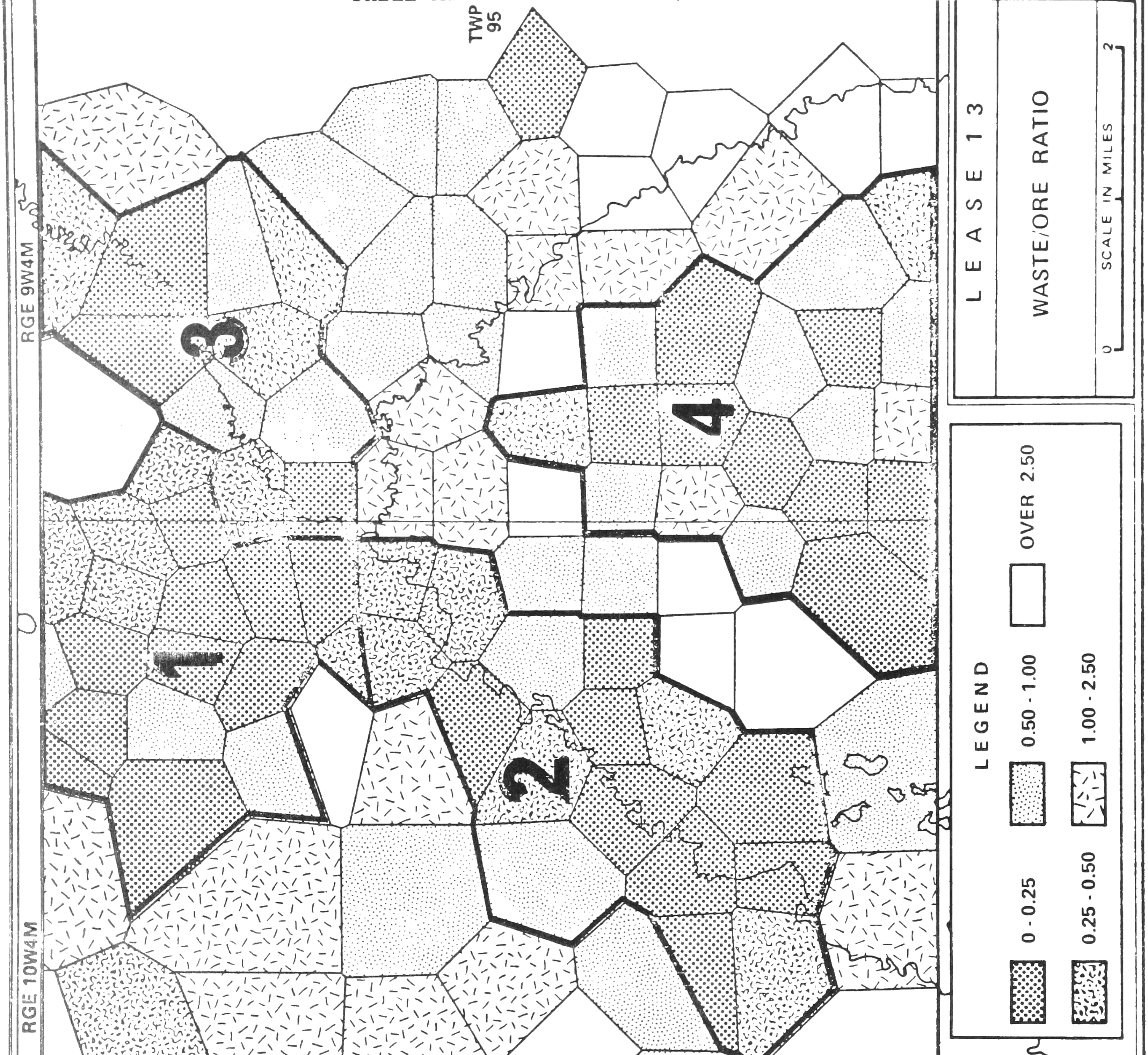

LEASE 13
WASTE/ORE RATIO
SCALE IN MILES
0
2
LEGEND
0 - 0.25
0.25 - 0.50
0.50 - 1.00
1.00 - 2.50
OVER 2.50
RGE 9W4M
RGE 10W4M
TWP 95
TWP 95
1
2
3
4
ATHABASCA RIVER
FORT MACKAY SETTLEMENT

FIGURE 13

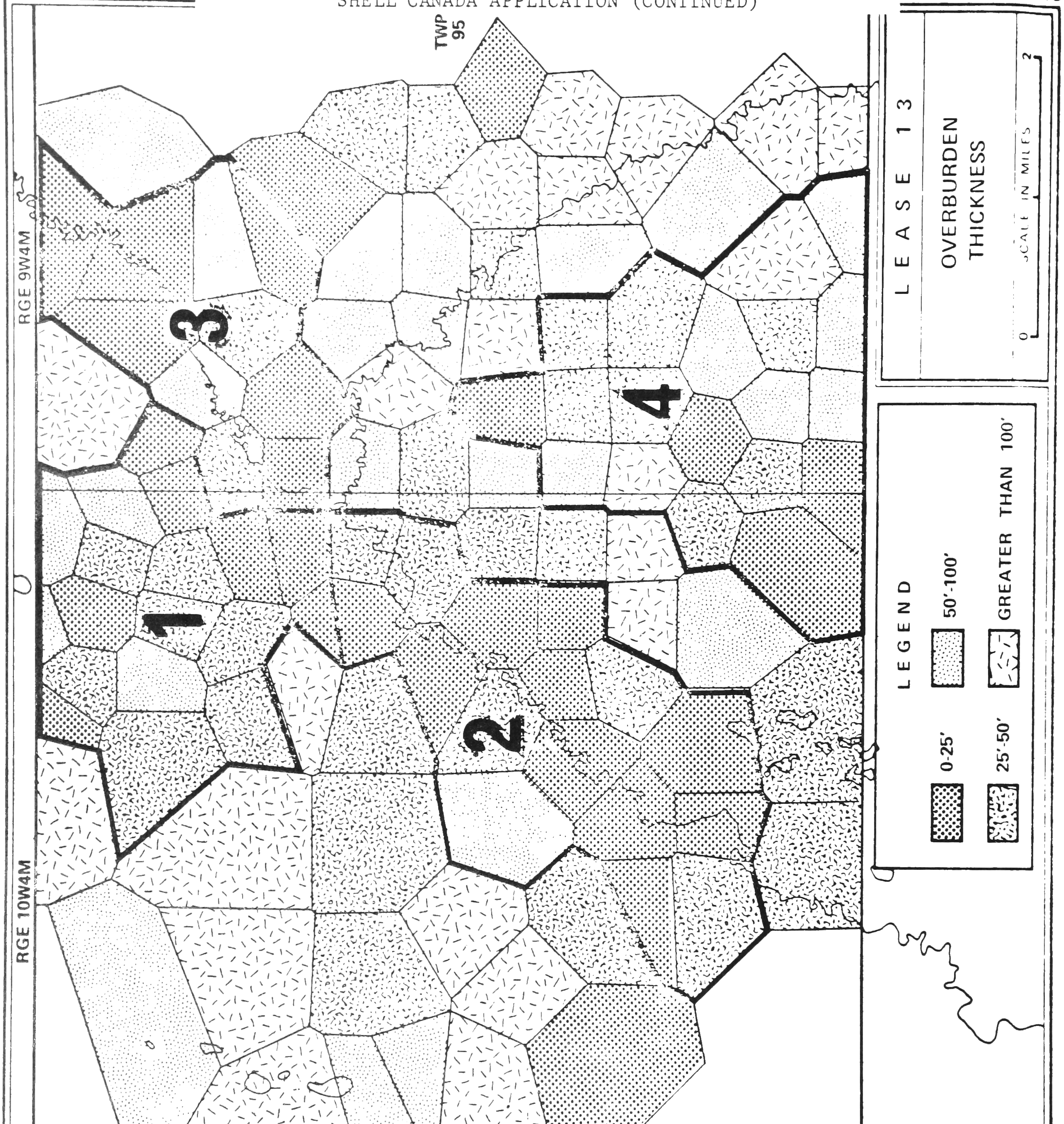
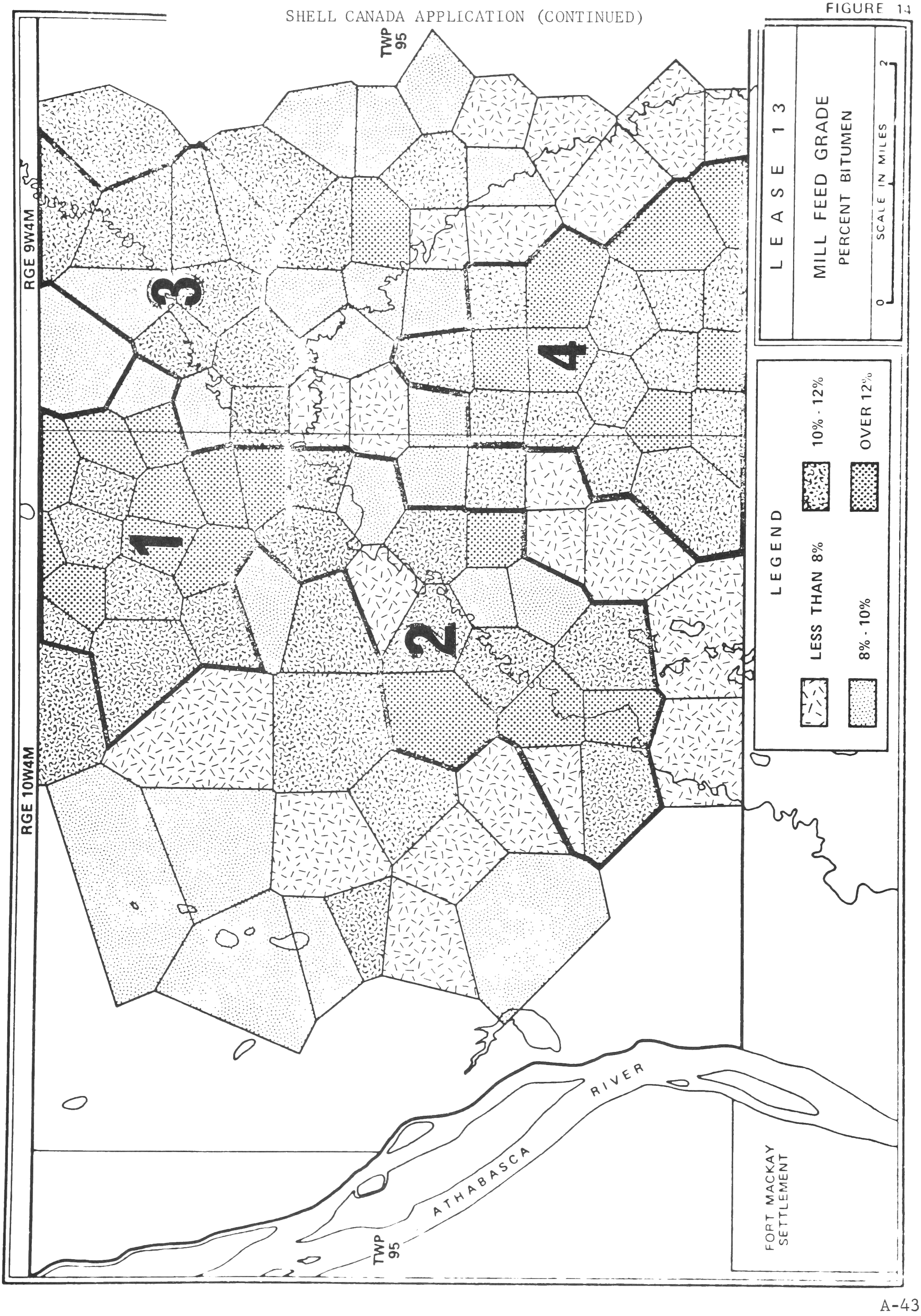

LEASE 13
OVERBURDEN
THICKNESS
SCALE IN MILES
0
2
LEGEND
0-25'
25'-50'
50'-100'
GREATER THAN 100'
RGE 9W4M
RGE 10W4M
TWP 95
TWP 95
ATHABASCA
RIVER
FORT MACKAY SETTLEMENT
1
2
3
4

FIGURE 14


LEASE 13
MILL FEED GRADE
PERCENT BITUMEN
SCALE IN MILES
0
2
LEGEND
LESS THAN 8%
8% - 10%
10% - 12%
OVER 12%
RGE 9W4M
RGE 10W4M
TWP 95
TWP 95
1
2
3
4
ATHABASCA RIVER
FORT MACKAY SETTLEMENT

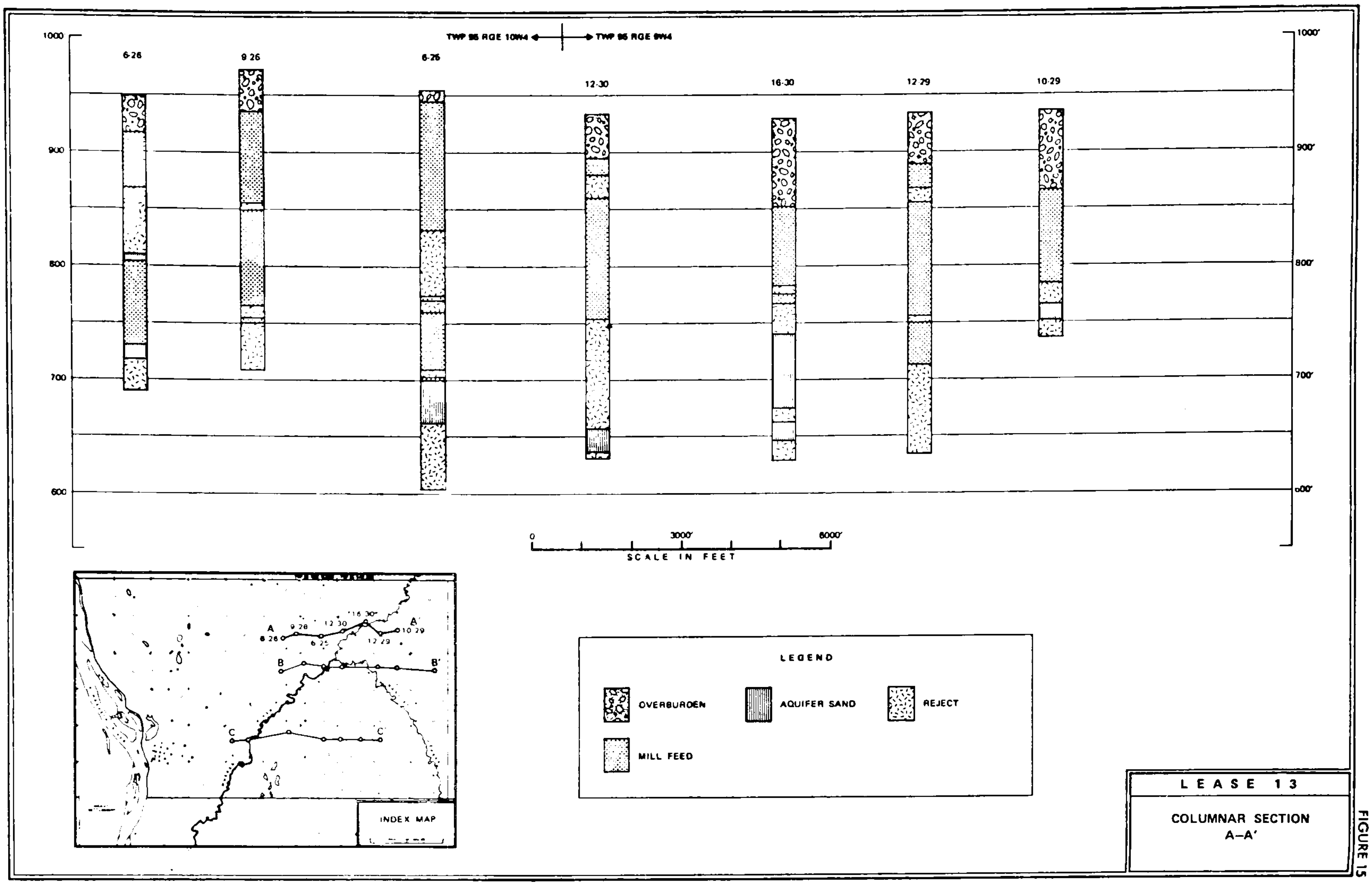


FIGURE 15

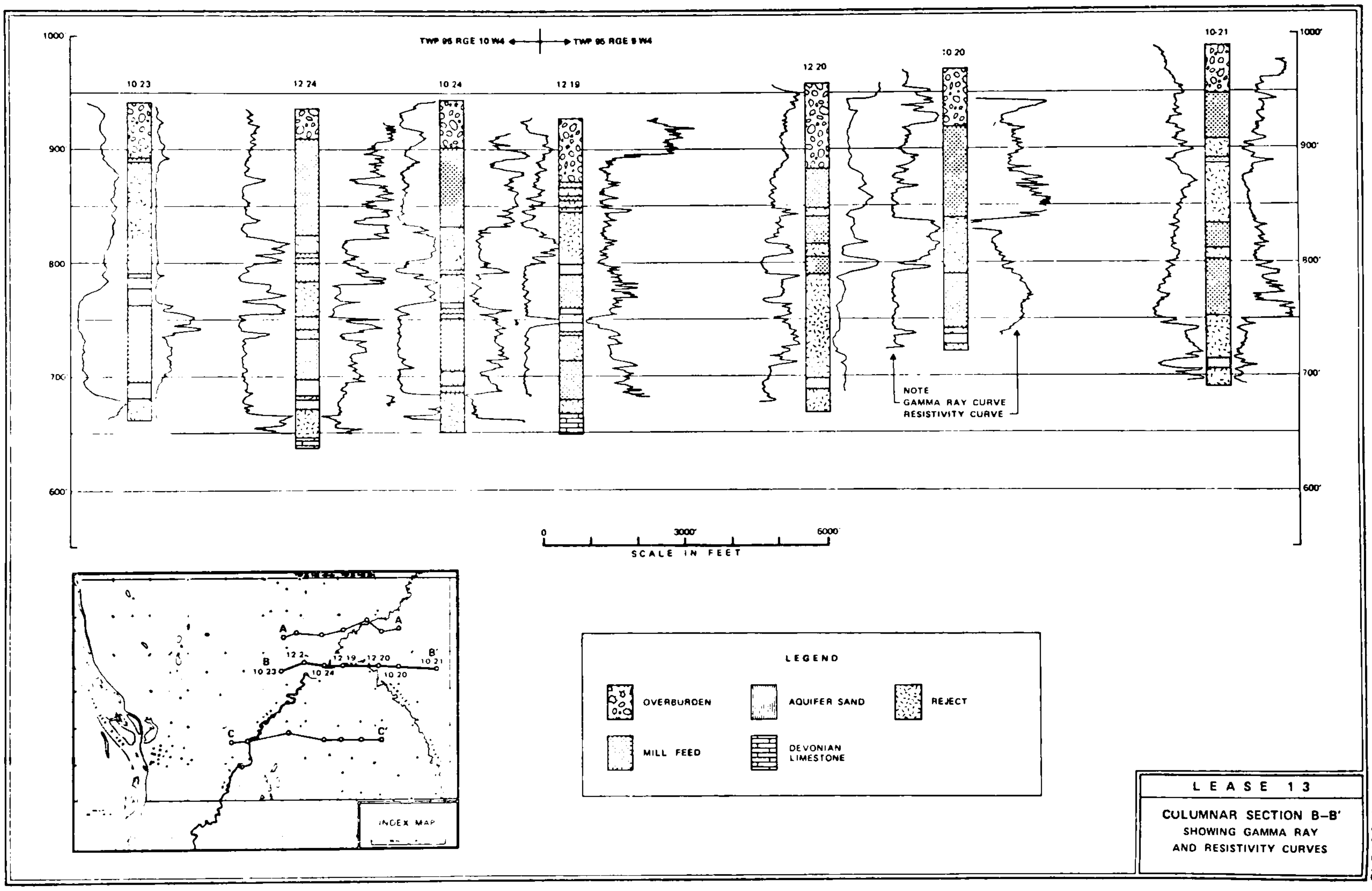
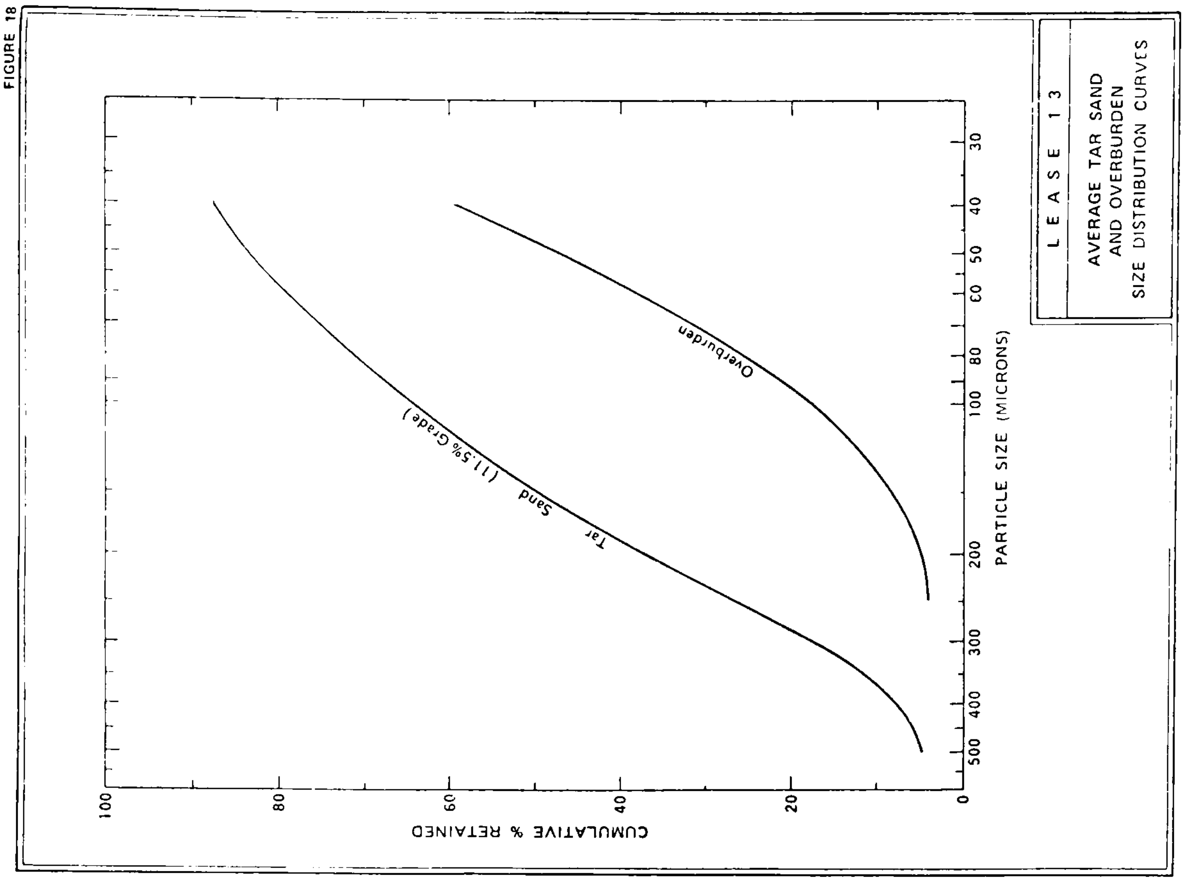


FIGURE 16

FIGURE 18



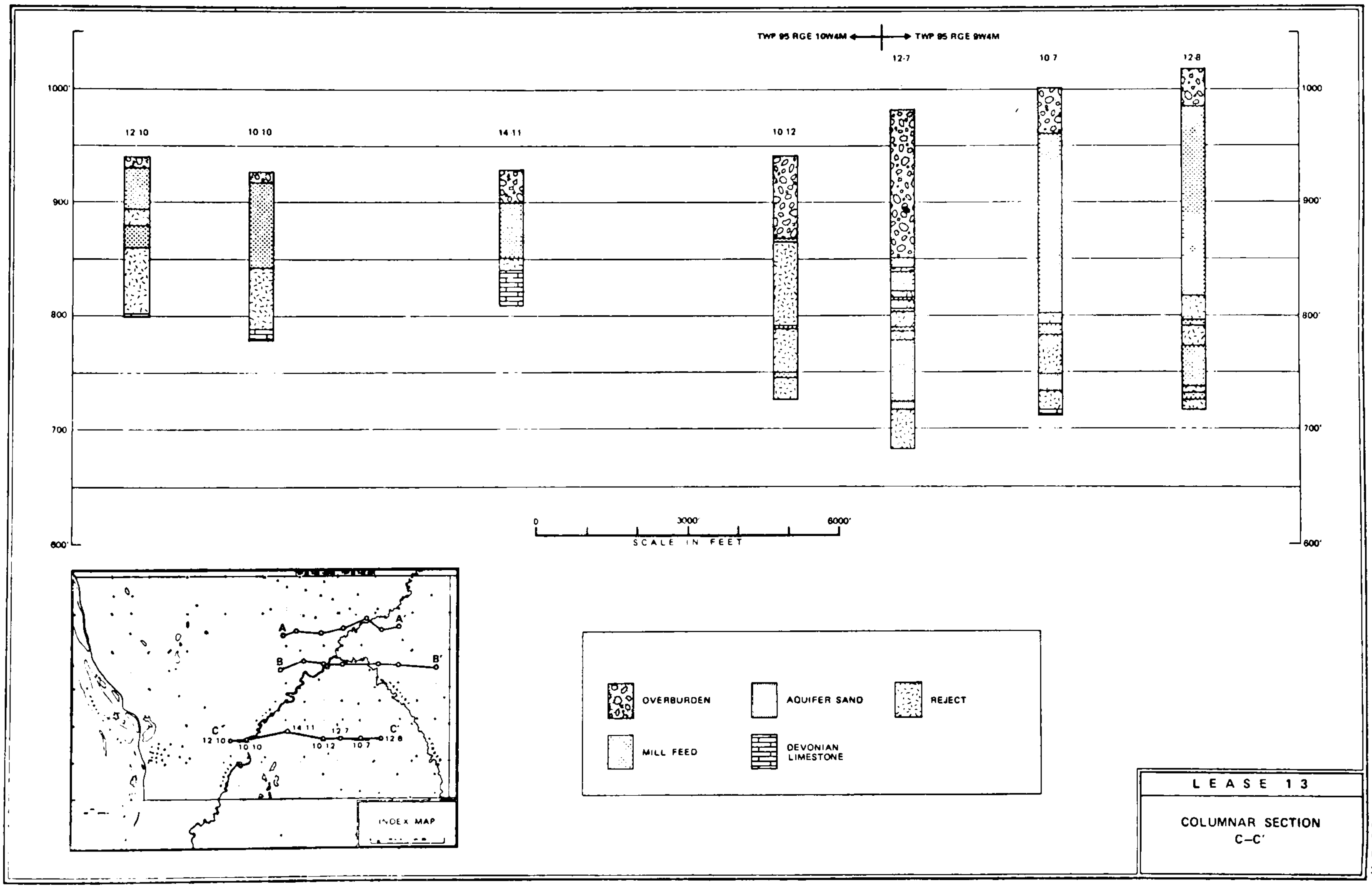
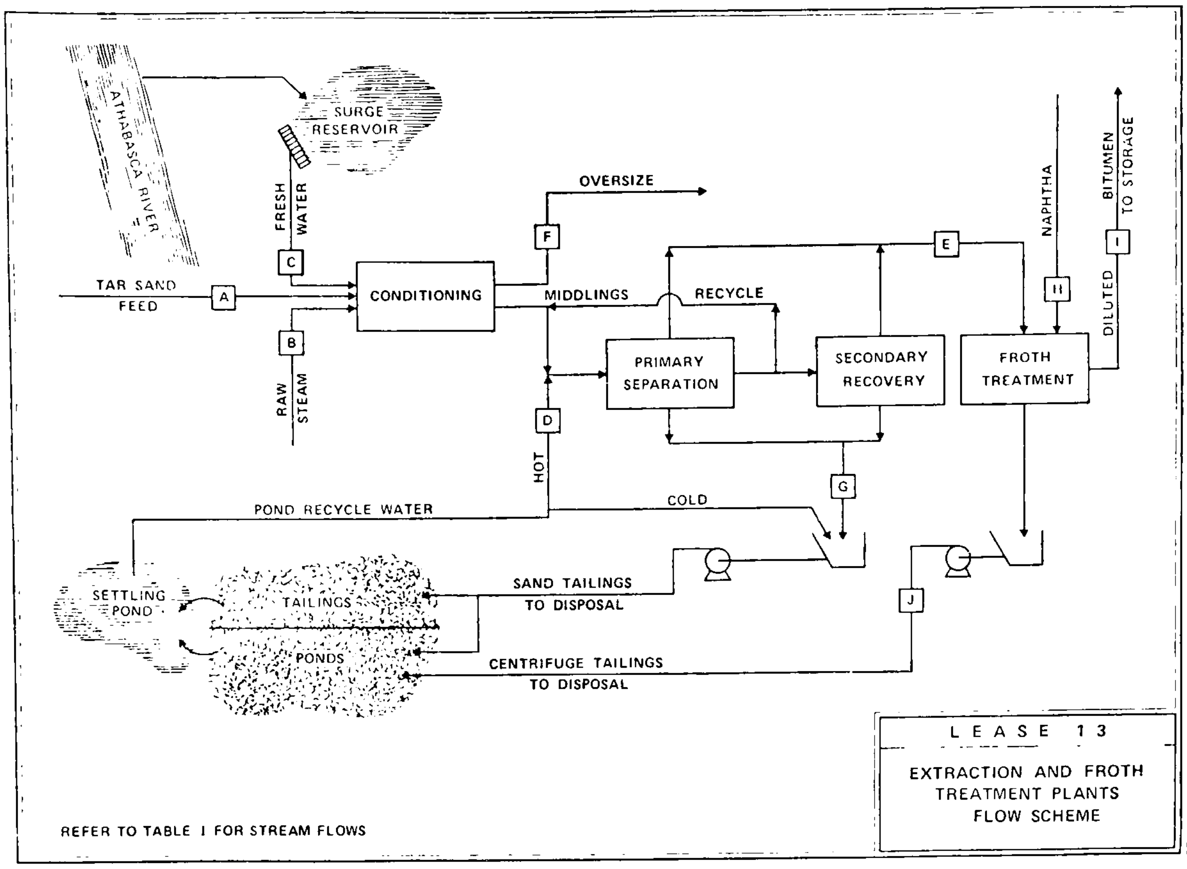


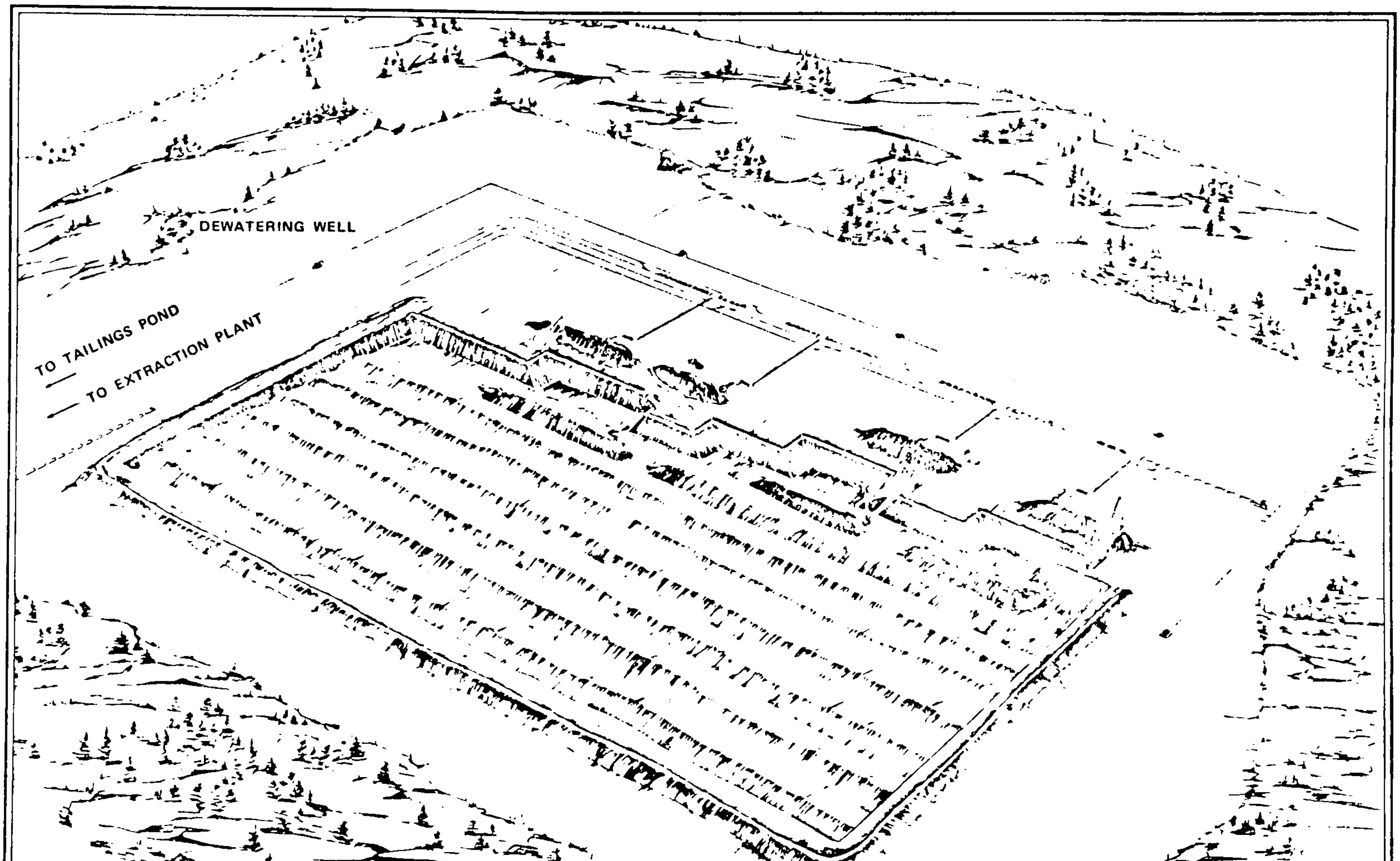
FIGURE 17



LEASE 13

EXTRACTION AND FROTH TREATMENT PLANTS FLOW SCHEME

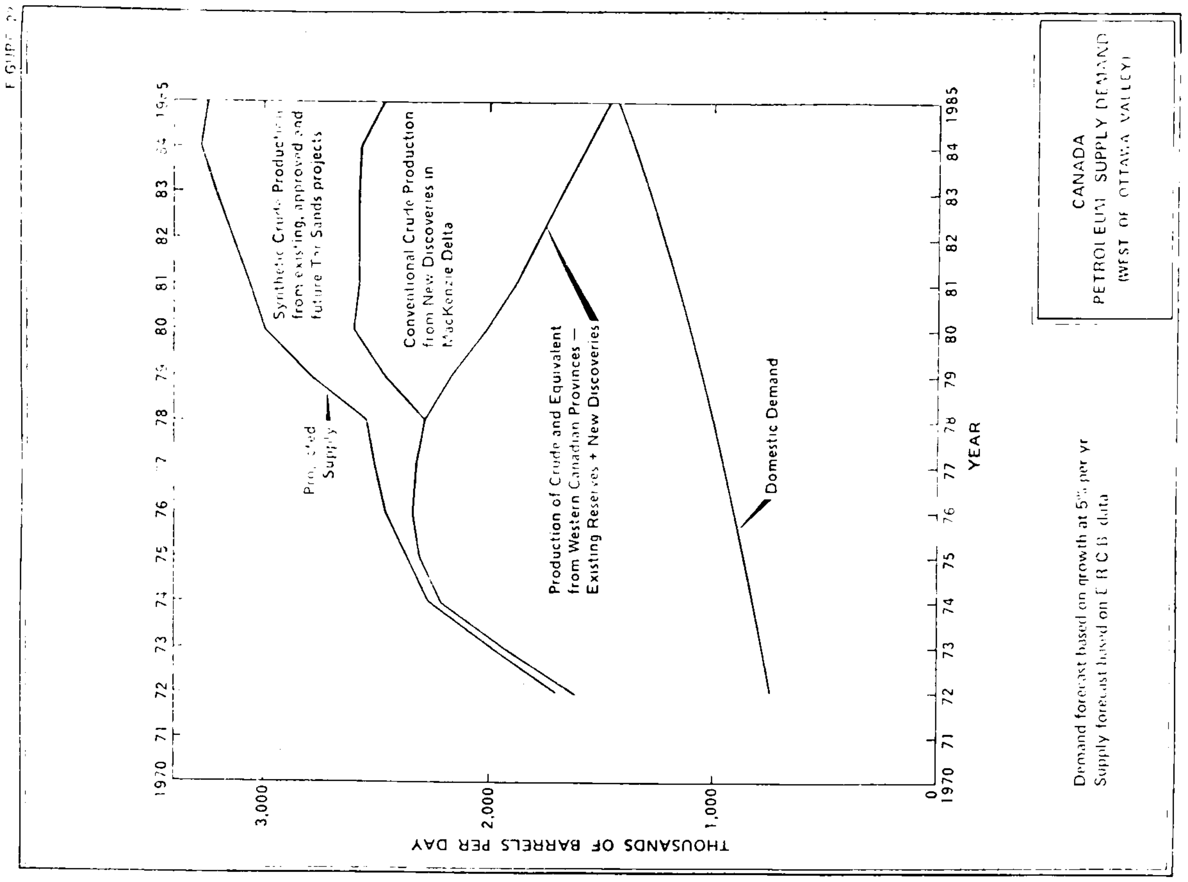
FIGURE 20

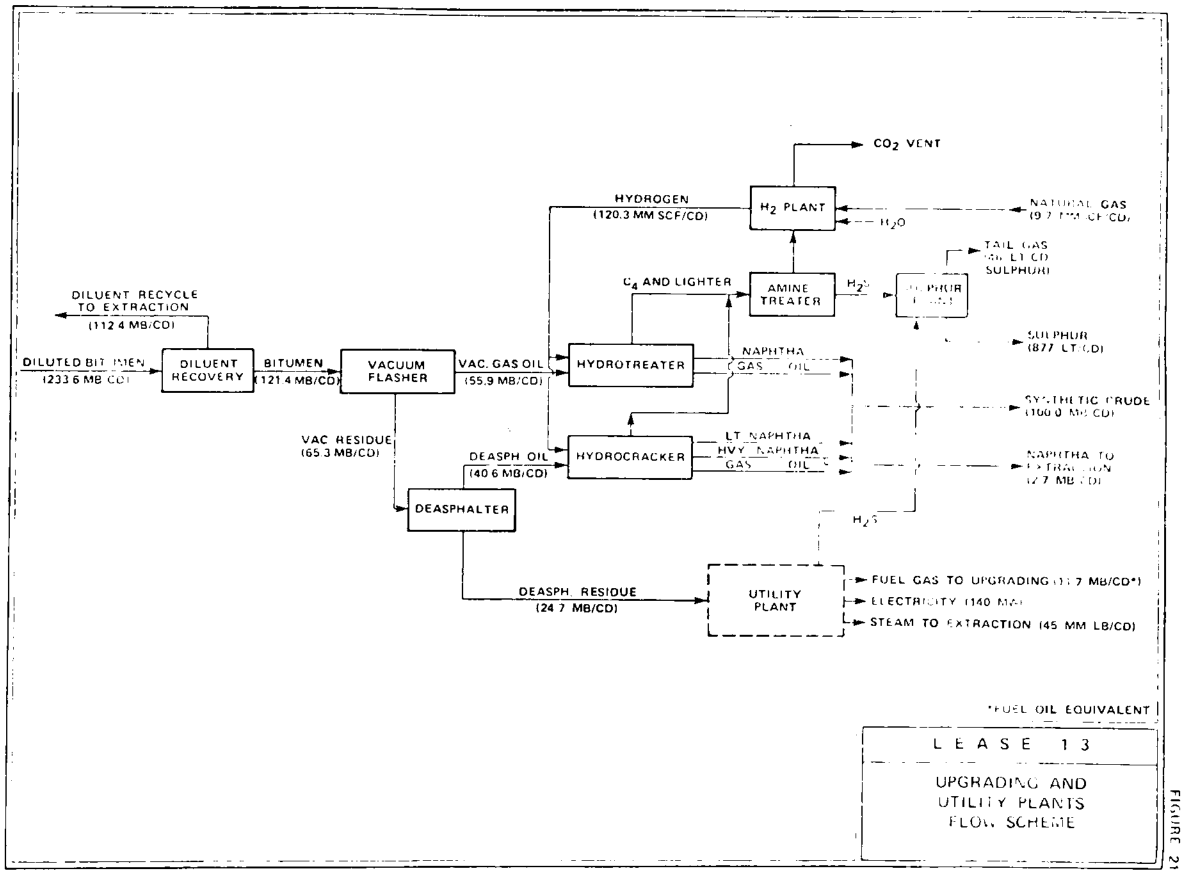


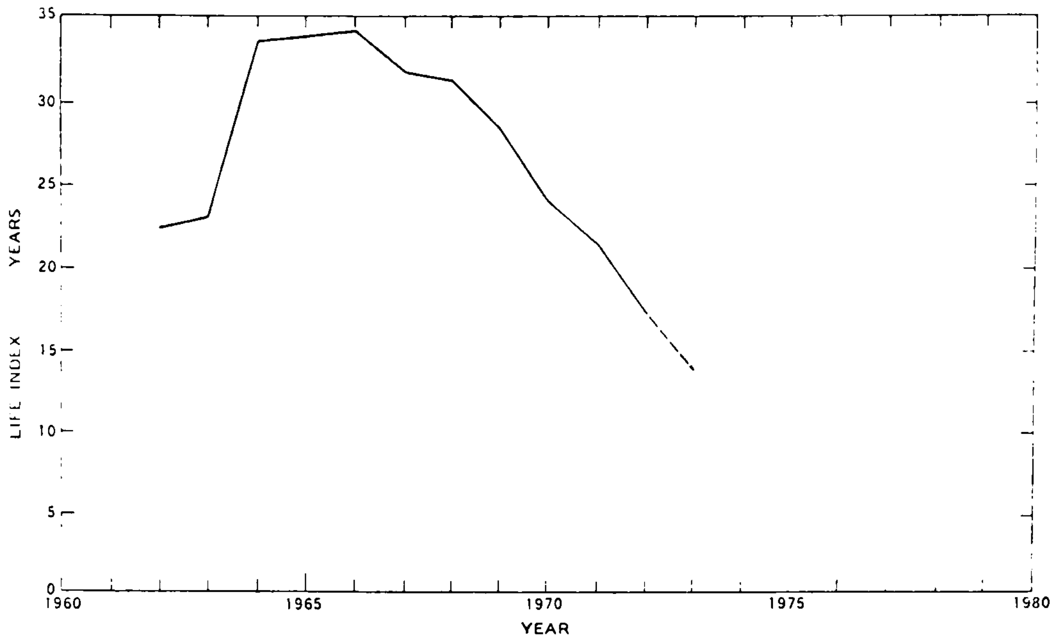
LEASE 13

MINING PROGRESS AT YEAR THREE (NOT TO SCALE)

FIGURE 19


CANADA
PETROLEUM SUPPLY DEMAND
THOUSANDS OF BARRELS PER DAY
YEAR
Domestic Demand
Production of Crude and Equivalent
from Western Canadian Provinces —
Existing Reserves + New Discoveries
Conventional Crude Production
Demand forecast based on growth at 5% per yr

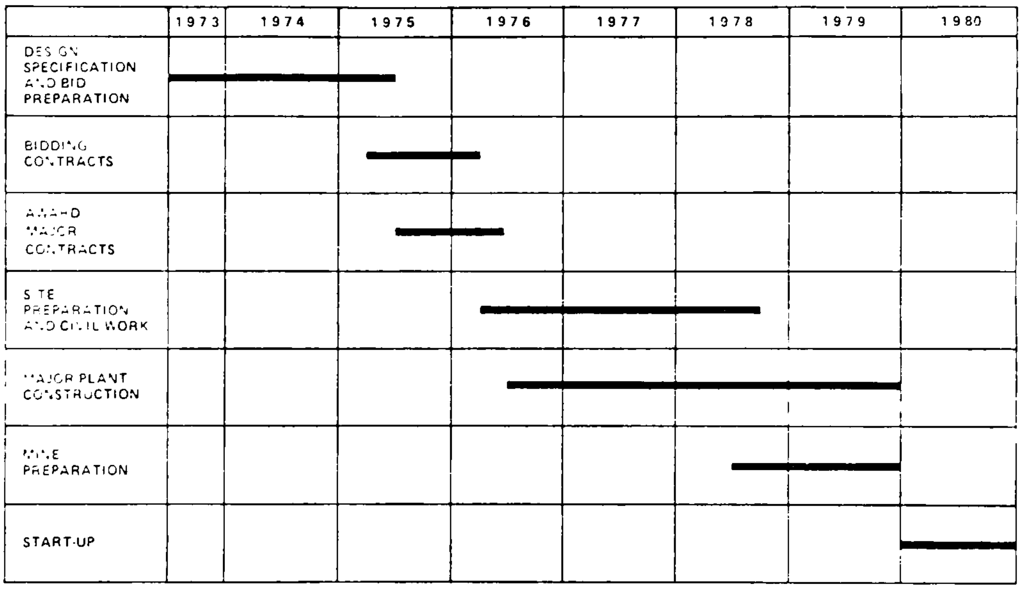

CO2 VENT
HYDROGEN
(120.3 MM SCF/CD)
H2 PLANT
C4 AND LIGHTER
AMINE TREATER
DILUENT RECYCLE TO EXTRACTION
DILUTED BITUMEN
DILUENT RECOVERY
BITUMEN
(121.4 MB/CD)
VACUUM FLASHER
VAC. GAS OIL
(55.9 MB/CD)
HYDROTREATER
NAPHTHA
VAC RESIDUE
(65.3 MB/CD)
DEASPH OIL
(40.6 MB/CD)
HYDROCRACKER
LT NAPHTHA
DEASPHALTER
DEASPH. RESIDUE
(24.7 MB/CD)
UTILITY PLANT
STEAM TO EXTRACTION (45 MM LB/CD)
FUEL OIL EQUIVALENT
LEASE 13
UPGRADING AND
UTILITY PLANTS



SOURCE: E.R.C.B. Annual Statistics

ALBERTA
CONVENTIONAL CRUDE OIL
LIFE INDEX

FIGURE 23



LEASE 13

PROJECT SCHEDULE

FIGURE 24

TABLE A

BULK AND GRAIN DENSITY INFORMATION FROM FDC LOG 1971 PROGRAM

WELL	CLEAN SAND FT.	CLEAN SAND BULK DENSITY	GRADE ORE >6% T.W. FT.	GRADE ORE >6% T.W. BULK DENSITY	CLAY BULK DENSITY	GRAIN DENSITY
10-6-95-9 W4	55	2.09	103	2.11	2.40	
12-13-95-9	190	2.08	208	2.08	-	
4-23-95-9	40	2.13	151	2.15	2.33	
2-26-95-9	120	2.05	91	2.05	2.35	2.643
2-27-95-9	40	2.10	86	2.15	2.34	
12-29-95-9	50	2.13	162	2.15	-	
4-36-95-9	100	2.12	165	2.13	2.38	
10-12-95-10	THIN	-	-	-	2.33	
4-10-95-10	THIN	-	80	2.15	2.30	
10-13-95-10	80	2.16	87	2.16	2.37	
10-24-95-10	110	2.02	132	2.02	2.38	
14-25-95-10	60	2.09	137	2.10	2.33	2.630
AVERAGE		2.08		2.10	2.35	2.636
POROSITY BASED ON GD OF 2.64 GMS/CC		34.1%		32.9%		

BORE HOLE DATA FOR MINING AREAS 1 AND 2

MINING AREA 1

HOLE LOCATION LSD SEC TWP RGE	POLYGON AREA MM. SQ.FT.	OVERBURDEN FEET	OVERBURDEN PCT BITUMEN	CENTRE REJECT FEET	CENTRE REJECT PCT BITUMEN	BOTTOM REJECT FEET	BOTTOM REJECT PCT BITUMEN	MILL FEED FEET	MILL FEED PCT BITUMEN	WASTE/ORE RATIO OVERBURDEN AND CENTRE REJECT TO MILL FEED	QUALITY FACTOR
3-31-95- 9-4	5.752	0.	0.0	35.	4.2	149.	2.6	134.	9.2	0.26	3.9
12-24-95-10-4	5.600	23.	0.0	61.	2.0	49.	0.4	167.	11.7	0.50	7.5
2-25-95-10-4	7.224	0.	0.0	48.	3.5	51.	1.4	201.	12.3	0.24	11.4
6-25-95-10-4	7.332	5.	0.0	0.	0.0	217.	3.3	128.	13.2	0.04	9.7
13-25-95-10-4	6.200	28.	0.0	0.	0.0	32.	0.0	198.	13.3	0.14	14.4
14-25-95-10-4	6.800	25.	0.0	10.	5.1	150.	1.3	141.	13.3	0.25	10.0
16-25-95-10-4	5.600	3.	0.0	55.	2.4	75.	1.3	252.	13.1	0.23	16.8
6-26-95-10-4	10.148	26.	0.0	64.	0.9	29.	0.0	139.	11.6	0.65	5.8
9-26-95-10-4	7.840	33.	0.0	5.	1.6	46.	2.3	181.	13.4	0.21	13.0
2-35-95-10-4	8.068	93.	0.0	0.	0.0	33.	2.0	114.	11.1	0.82	3.7
4-35-95-10-4	18.240	36.	0.0	6.	5.1	26.	0.0	189.	10.8	0.22	8.0
10-35-95-10-4	6.400	25.	0.0	11.	4.6	0.	0.0	254.	12.4	0.14	16.0
14-35-95-10-4	4.080	0.	0.0	42.	4.9	18.	3.7	213.	11.7	0.20	11.2
16-35-95-10-4	2.760	56.	0.0	0.	0.0	120.	1.7	110.	12.0	0.51	5.6
8-36-95-10-4	7.160	51.	0.0	31.	2.7	12.	5.9	198.	12.3	0.41	10.1
10-36-95-10-4	5.520	34.	0.0	36.	5.6	50.	0.3	144.	11.8	0.49	6.9
12-36-95-10-4	7.048	15.	0.0	7.	4.6	27.	2.3	186.	11.9	0.12	10.9
15-36-95-10-4	7.160	46.	0.0	0.	0.0	20.	0.0	152.	13.0	0.30	10.0

MINING AREA 2

HOLE LOCATION LSD SEC TWP RGE	POLYGON AREA MM. SQ.FT.	OVERBURDEN FEET	OVERBURDEN PCT BITUMEN	CENTRE REJECT FEET	CENTRE REJECT PCT BITUMEN	BOTTOM REJECT FEET	BOTTOM REJECT PCT BITUMEN	MILL FEED FEET	MILL FEED PCT BITUMEN	WASTE/ORE RATIO OVERBURDEN AND CENTRE REJECT TO MILL FEED	QUALITY FACTOR
2-10-95-10-4	8.400	0.	0.0	5.	3.1	13.	4.8	94.	13.2	0.05	6.6
4-10-95-10-4	15.612	28.	0.0	0.	0.0	7.	1.0	95.	10.7	0.29	4.2
10-10-95-10-4	11.040	3.	0.0	0.	0.0	53.	1.8	91.	12.6	0.03	6.3
12-10-95-10-4	9.080	4.	0.0	13.	4.1	51.	0.7	74.	7.5	0.23	1.1
4-11-95-10-4	15.340	5.	0.0	0.	0.0	80.	0.7	56.	10.3	0.09	3.0
14-11-95-10-4	9.760	25.	0.0	0.	0.0	34.	0.3	62.	9.8	0.40	1.8
4-13-95-10-4	7.000	14.	0.0	8.	4.4	22.	0.7	114.	12.6	0.19	7.4
12-13-95-10-4	10.320	6.	0.0	98.	3.7	0.	0.0	166.	10.1	0.63	4.5
2-14-95-10-4	6.480	0.	0.0	0.	0.0	44.	0.9	76.	9.5	0.0	2.9
4-14-95-10-4	11.400	16.	0.0	0.	0.0	56.	1.9	83.	10.9	0.19	4.2
11-14-95-10-4	11.440	40.	0.0	28.	0.1	24.	0.0	157.	10.5	0.43	5.8
10-15-95-10-4	17.968	85.	0.0	20.	4.8	5.	1.4	134.	12.0	0.78	5.5
2-23-95-10-4	10.408	1.	0.0	0.	0.0	249.	5.3	33.	4.5	0.03	0.2
3-24-95-10-4	9.580	25.	0.0	0.	0.0	246.	2.0	60.	9.8	0.42	2.2
10-24-95-10-4	6.920	37.	0.0	0.	0.0	173.	4.2	86.	11.3	0.43	4.1
12-24-95-10-4	5.600	23.	0.0	61.	2.0	49.	0.4	167.	11.7	0.50	7.5

TABLE B

QUALTY FACTOR $= \sum (H_{mf} \times G_{mf}) - (H_{mf} \times G_{min}) - (H_{rej} \times \frac{G_{min}}{2})$

H = thickness in feet
G = grade in fractional total weight tar
mf refers to mill feed
rej refers to reject (overburden & centre)
min refers to minimum grade (.06 fractional total weight tar)

TABLE C

BORE HOLE DATA FOR MINING AREAS 3 AND 4

MINING AREA 3

HOLE LOCATION LSD SEC TWP RGE	POLYGON AREA MM. SQ.FT.	OVERBURDEN FEET	OVERBURDEN PCT BITUMEN	CENTRE REJECT FEET	CENTRE REJECT PCT BITUMEN	BOTTOM REJECT FEET	BOTTOM REJECT PCT BITUMEN	MILL FEED FEET	MILL FEED PCT BITUMEN	WASTE/ORE RATIO OVERBURDEN AND CENTRE REJECT TO MILL FEED	QUALITY FACTOR
2-29-95- 9-4	9.360	5.	0.0	40.	2.8	275.	0.6	135.	10.9	0.33	6.0
10-29-95- 9-4	10.332	65.	0.0	0.	0.0	37.	1.9	98.	10.9	0.66	3.5
12-29-95- 9-4	9.740	40.	0.0	12.	3.9	67.	0.0	181.	11.8	0.29	9.6
2-30-95- 9-4	11.120	15.	0.0	45.	1.8	128.	0.7	112.	10.6	0.54	4.1
4-30-95- 9-4	7.000	8.	0.0	5.	0.0	136.	3.8	154.	10.6	0.08	7.5
12-30-95- 9-4	7.840	33.	0.0	20.	3.9	112.	0.4	137.	9.3	0.39	3.7
16-30-95- 9-4	7.840	73.	0.0	7.	3.6	128.	0.5	93.	10.1	0.86	2.2
2-32-95- 9-4	15.440	8.	0.0	6.	5.6	70.	1.9	116.	11.3	0.12	6.3
4-32-95- 9-4	12.000	0.	0.0	16.	4.6	150.	0.8	134.	9.4	0.12	4.3
9-32-95- 9-4	12.380	3.	0.0	51.	3.0	10.	0.0	142.	11.5	0.38	7.0

MINING AREA 4

HOLE LOCATION LSD SEC TWP RGE	POLYGON AREA MM. SQ.FT.	OVERBURDEN FEET	OVERBURDEN PCT BITUMEN	CENTRE REJECT FEET	CENTRE REJECT PCT BITUMEN	BOTTOM REJECT FEET	BOTTOM REJECT PCT BITUMEN	MILL FEED FEET	MILL FEED PCT BITUMEN	WASTE/ORE RATIO OVERBURDEN AND CENTRE REJECT TO MILL FEED	QUALITY FACTOR
1- 5-95- 9-4	7.408	71.	0.0	21.	3.4	11.	0.8	203.	12.3	0.45	10.7
4- 5-95- 9-4	6.732	96.	0.0	41.	3.0	3.	0.0	160.	10.8	0.86	4.1
10- 5-95- 9-4	13.588	127.	0.0	8.	5.4	0.	0.0	175.	12.4	0.77	8.0
12- 5-95- 9-4	6.700	46.	0.0	0.	0.0	14.	0.0	215.	11.3	0.21	10.6
2- 6-95- 9-4	6.040	69.	0.0	0.	0.0	90.	3.5	63.	12.0	1.10	2.1
4- 6-95- 9-4	8.872	8.	0.0	5.	5.6	171.	5.3	83.	11.3	0.16	4.2
10- 6-95- 9-4	6.648	50.	0.0	26.	4.9	110.	3.9	114.	10.0	0.67	3.1
12- 6-95- 9-4	6.860	29.	0.0	10.	5.4	50.	1.3	211.	12.9	0.18	13.6
16- 6-95- 9-4	9.248	69.	0.0	38.	2.5	17.	2.5	171.	11.7	0.63	7.2
3- 7-95- 9-4	7.600	17.	0.0	5.	5.1	102.	2.6	176.	11.5	0.13	9.4
10- 7-95- 9-4	8.220	35.	0.0	9.	0.8	61.	1.7	185.	12.5	0.24	11.2
12- 7-95- 9-4	7.280	126.	0.0	37.	4.2	31.	0.1	106.	10.3	1.54	0.3
12- 8-95- 9-4	13.052	28.	0.0	0.	0.0	90.	5.6	182.	13.1	0.15	12.4
4-17-95- 9-4	7.680	25.	0.0	75.	3.4	12.	1.3	150.	10.7	0.67	4.8
2-18-95- 9-4	6.920	31.	0.0	5.	5.6	98.	1.0	166.	12.8	0.22	10.8
4-18-95- 9-4	7.000	79.	0.0	51.	2.4	0.	0.0	165.	11.2	0.79	5.5
10-18-95- 9-4	8.888	0.	0.0	70.	2.0	19.	0.0	148.	10.7	0.47	5.5
10- 1-95-10-4	19.040	13.	0.0	0.	0.0	104.	4.7	83.	10.6	0.16	3.7
1-12-95-10-4	7.880	32.	0.0	90.	3.2	7.	0.1	142.	10.5	0.86	3.5

QUALTY FACTOR = $\sum (H_{mf} \times G_{mf}) - (H_{mf} \times G_{min}) - (H_{rej} \times \frac{G_{min}}{2})$

H = thickness in feet
G = grade in fractional total weight tar
mf refers to mill feed
rej refers to reject (overburden & centre)
min refers to minimum grade (.06 fractional total weight tar)

TABLE D

BORE HOLE DATA FOR AREA OUTSIDE OREBODY

OUTSIDE OREBODY

HOLE LOCATION LSD SEC TWP RGE	POLYGON AREA MM. SQ.FT.	OVERBURDEN FEET	OVERBURDEN PCT BITUMEN	CENTRE REJECT FEET	CENTRE REJECT PCT BITUMEN	BOTTOM REJECT FEET	BOTTOM REJECT PCT BITUMEN	MILL FEED FEET	MILL FEED PCT BITUMEN	WASTE/ORE RATIO OVERBURDEN AND CENTRE REJECT TO MILL FEED	QUALITY FACTOR
2- 4-95- 9-4	6.440	165.	0.0	14.	2.4	43.	3.0	53.	6.3	3.38	-4.4
10- 4-95- 9-4	12.800	180.	0.7	0.	0.0	96.	3.2	24.	3.6	7.50	-5.2
4- 9-95- 9-4	15.820	52.	0.0	0.	0.0	230.	2.1	33.	5.3	1.58	-1.0
6- 9-95- 9-4	11.620	216.	1.3	0.	0.0	223.	0.4	31.	4.4	6.97	-5.2
2-16-95- 9-4	9.568	166.	0.3	0.	0.0	114.	2.4	20.	2.7	8.30	-4.9
4-16-95- 9-4	8.588	174.	0.0	5.	5.9	87.	0.0	54.	9.1	3.31	-3.0
9-16-95- 9-4	9.732	5.	0.0	35.	2.1	151.	3.2	156.	9.3	0.26	4.4
12-16-95- 9-4	10.300	148.	0.0	20.	3.5	11.	5.1	114.	10.2	1.47	0.0
2-17-95- 9-4	9.740	61.	0.0	0.	0.0	260.	1.5	36.	7.1	1.69	-0.7
10-17-95- 9-4	6.960	36.	0.0	5.	4.5	190.	3.5	37.	5.0	1.11	-0.8
12-17-95- 9-4	8.128	119.	0.0	67.	1.5	52.	3.4	62.	9.3	3.00	-2.8
12-18-95- 9-4	6.540	91.	0.0	67.	4.4	23.	4.6	54.	8.8	2.93	-2.5
4-19-95- 9-4	9.980	36.	0.0	21.	5.3	199.	2.6	33.	6.7	1.73	-0.7
8-19-95- 9-4	9.060	113.	0.0	0.	0.0	224.	3.3	50.	8.7	2.26	-1.3
12-19-95- 9-4	8.848	51.	2.1	0.	0.0	209.	5.1	21.	1.7	2.43	-1.7
2-20-95- 9-4	9.288	79.	0.0	0.	0.0	127.	3.1	85.	12.4	0.93	3.5
4-20-95- 9-4	7.020	53.	0.0	16.	5.6	131.	2.3	77.	9.0	0.90	1.0
10-20-95- 9-4	9.560	47.	0.0	45.	1.0	9.	1.2	148.	10.4	0.62	4.3
12-20-95- 9-4	8.212	70.	0.0	19.	3.1	104.	1.1	89.	9.4	1.00	1.1
16-20-95- 9-4	14.308	5.	0.0	87.	2.9	100.	0.0	103.	11.1	0.89	2.9
2-21-95- 9-4	8.960	46.	0.0	32.	4.6	68.	1.0	154.	8.3	0.51	1.9
10-21-95- 9-4	11.792	38.	0.0	80.	3.4	50.	0.8	132.	9.2	0.89	1.2
6-31-95- 9-4	17.180	117.	0.0	6.	0.0	199.	1.3	48.	8.0	2.56	-2.0
6-33-95- 9-4	19.080	69.	0.0	8.	5.5	256.	0.9	67.	10.3	1.15	0.9
5- 2-95-10-4	24.120	35.	0.0	0.	0.0	39.	0.0	37.	7.0	0.95	0.1
6- 3-95-10-4	19.200	45.	0.0	0.	0.0	47.	0.0	26.	4.5	1.73	-1.1
4-12-95-10-4	16.800	87.	1.0	0.	0.0	90.	1.7	21.	1.9	4.14	-2.7
10-12-95-10-4	6.840	145.	1.2	0.	0.0	52.	3.1	18.	2.2	8.06	-4.3
12-12-95-10-4	7.480	265.	0.0	0.	0.0	0.	0.0	0.	0.0	******	-100.0
2-13-95-10-4	7.200	37.	0.0	12.	0.2	78.	4.4	83.	10.9	0.59	3.2
10-13-95-10-4	7.840	40.	0.0	41.	3.4	116.	0.7	103.	9.6	0.79	1.9
4-15-95-10-4	11.504	41.	0.0	10.	5.4	137.	3.3	67.	6.3	0.76	-0.6
4-16-95-10-4	34.232	13.	0.0	45.	4.3	76.	2.6	107.	8.1	0.54	0.5
10-16-95-10-4	12.800	143.	0.0	0.	0.0	116.	2.1	23.	2.9	6.22	-4.2
16-16-95-10-4	14.328	103.	0.0	13.	1.8	3.	0.0	102.	10.6	1.14	2.0
16-17-95-10-4	15.500	111.	0.0	0.	0.0	110.	1.3	70.	6.9	1.59	-1.9
1-20-95-10-4	8.520	89.	0.0	0.	0.0	27.	0.0	158.	10.4	0.56	4.9
10-20-95-10-4	10.680	50.	0.0	42.	1.6	24.	0.0	163.	9.3	0.56	2.9
7-21-95-10-4	20.228	43.	0.0	0.	0.0	187.	5.0	25.	3.2	1.72	-1.2
11-22-95-10-4	25.040	33.	0.0	57.	5.0	16.	0.0	130.	10.0	0.69	3.2
10-23-95-10-4	14.068	43.	0.0	126.	2.1	23.	1.3	88.	10.4	1.92	-0.5
2-26-95-10-4	10.000	107.	0.9	8.	5.1	122.	3.9	42.	8.9	2.74	-1.5
6-27-95-10-4	31.848	104.	0.0	0.	0.0	142.	4.7	45.	7.9	2.31	-1.5
10-28-95-10-4	26.144	146.	0.0	5.	2.5	18.	0.0	67.	8.3	2.25	-2.3
2-29-95-10-4	30.200	105.	1.3	22.	2.4	1.	0.0	102.	8.1	1.25	-1.0
3-33-95-10-4	40.200	77.	0.0	0.	0.0	16.	0.5	163.	8.5	0.47	1.9
16-34-95-10-4	16.624	165.	0.0	0.	0.0	168.	2.8	77.	10.8	2.14	-0.5

QUALTY FACTOR = $\sum (H_{mf} \times G_{mf}) - (H_{mf} \times G_{min}) - (H_{rej} \times \frac{G_{min}}{2})$

H = thickness in feet
G = grade in fractional total weight tar
mf refers to mill feed
rej refers to reject (overburden & centre)
min refers to minimum grade (.06 fractional total weight tar)

OREBODY PARAMETERS

	AREA (MILLION SQ. FEET)	AVERAGE						BITUMEN IN PLACE (MILLION BARRELS)	RE-COVERABLE BITUMEN (MILLION BARRELS)
		OVERBURDEN THICKNESS (FEET)	MILL FEED THICKNESS (FEET)	CENTRE REJECT THICKNESS (FEET)	MILL FEED GRADE (WEIGHT PERCENT)	WASTE/ORE RATIO	FINES (PERCENT)		
OREBODY AREA 1	129	29	173	22	12.1	.29	13.0	1,090	1,010
2	166	23	96	14	10.9	.38	16.0	780	650
3	103	23	129	21	10.7	.34	16.3	600	540
4	166	48	150	23	11.7	.48	13.7	1,250	1,080
TOTAL OREBODY	564	32	135	20	11.5	.38	14.3	3,720	3,280
PROCESS PLANT	8	58	-		-	2.89	N.A.	35	N.A.
TAILINGS PONDS	168	91	90	31	9.8	2.34	N.A.	700	N.A.

TABLE E

TABLE F

UNRECOVERED BITUMEN IN PIT WALLS AND CENTRE REJECT

OREBODY	PIT WALLS* MM BARRELS	CENTRE REJECT MM BARRELS	TOTAL MM BARRELS
1	12.7	28.8	41.5
2	9.9	26.2	36.1
3	5.6	24.2	29.8
4	17.0	45.3	62.3

* Assumes Pit Slopes of 60°

TABLE G

AN ANALYSIS OF THE PARAMETERS FOR THE EXCLUSION OF POLYGONS FROM THE PROPOSED MINING AREAS

POLYGON LOCATION	WASTE/ ORE RATIO	LOW GRADE	ISOLATION	PROPOSED RIVER DIVERSIONS
10- 4-95- 9-4	X			
4- 9-95- 9-4		X		
6- 9-95- 9-4	X			
4-16-95- 9-4	X			
12-16-95- 9-4			X	
2-17-95- 9-4	X			
10-17-95- 9-4		X		
12-17-95- 9-4	X			
12-18-95- 9-4	X			
4-19-95- 9-4	X			
8-19-95- 9-4	X			
12-19-95- 9-4		X		
2-20-95- 9-4			X	
4-20-95- 9-4				X
10-20-95- 9-4				X
12-20-95- 9-4				X
16-20-95- 9-4				X
2-21-95- 9-4			X	
10-21-95- 9-4			X	
5- 2-95-10-4				X
6- 3-95-10-4		X		
4-12-95-10-4	X			
10-12-95-10-4	X			
12-12-95-10-4		X		

TABLE H

MATERIAL SIZE DISTRIBUTION

CORRELATED TO PERCENT GAMMA DEFLECTION

WELL NO. 10-24-95-10W4

FOOTAGE	MATERIAL DESCRIPTION	% MINUS 325 MESH (WET SIEVING)	% GAMMA DEFLECTION	WEIGHT % BITUMEN
38 - 41	Overburden	46.0	Too thin	4.5
41 - 51	High grade tar sand	7.9	17	15.8
51 - 58	Low grade tar sand	31.2	36	8.8
58 - 111	High grade tar sand	12.6	12	16.0
111 - 180	Centre reject	67.5	60	1.6
180 - 267	Average grade tar sand	6.3	6	11.2

MATERIAL BALANCE - EXTRACTION AND FROTH TREATMENT

	Stream Designation	BITUMEN Tons per Day	BITUMEN Wt. %	BITUMEN BPCD	WATER Tons per Day	WATER Wt. %	SOLIDS Tons per Day	SOLIDS Wt. %	NAPHTHA Tons per Day	NAPHTHA Wt. %	NAPHTHA BPCD	Total Tons per Day	-325 Mesh (1) Tons per Day	-325 Mesh (1) Wt. % of Solids
EXTRACTION BALANCE														
STREAMS IN														
Tar Sand Feed	A	23,434	11.5	(132,489)	6,061	3.0	174,279	85.5				203,774	28,528	14.3
Steam to Conditioner	B				8,819	100.0						8,819		
Fresh Water	C				42,100	100.0						42,100		
Pond Recycle Water	D	252	0.2	(1,425)	123,500	98.0	2,268	1.8				126,020	2,268	100.0
Total In		23,686		(133,914)	180,480		176,547					380,713	30,796	
STREAMS OUT														
Froth	E	22,017	59.9	(124,478)	11,762	32.0	2,977	8.1				36,756	1,340	45.0
Oversize	F	68	10.0	(384)	68	10.0	544	80.0				680	218	40.0
Extraction Tailings	G	1,601	0.5	(9,052)	168,650	49.1	173,026	50.4				343,277	29,238	16.9
Total Out		23,686		(133,914)	180,480		176,547					380,713	30,796	
FROTH TREATER BALANCE														
STREAMS IN														
Froth	E	22,017	59.9	(124,478)	11,762	32.0	2,977	8.1				36,756	1,340	45.0
Naphtha	H				294	1.8			16,287	98.2	(115,101)	16,581		
Total In		22,017		(124,478)	12,056		2,977		16,287		(115,101)	53,337	1,340	
STREAMS OUT														
Diluted Bitumen	I	21,467	44.1	(121,368)	2,185	5.5	162	0.4	15,911	40.0	(112,444)	39,725	162	100.0
Centrifuge Tailings	J	550	4.0	(3,110)	9,871	72.5	2,815	20.7	376	2.8	(2,657)	13,612	1,178	41.8
Total Out		22,017		(124,478)	12,056		2,977		16,287		(115,101)	53,337	1,340	

Extraction plant bitumen recovery — 22,017/23,434 x 100 = 94.0%

Froth treatment plant bitumen recovery — 21,467/22,017 x 100 = 97.5%

Total Hydrocarbon recovery — (21,467-376)/23,434 x 100 - 90.0%

(1) Included in solids.

TABLE I

FRESH WATER REQUIREMENTS AS A FUNCTION OF ATHABASCA RIVER FLOW RATE

PERIOD OF OBSERVATION	TOTAL RIVER FLOW (CU. FT./SEC.)	TOTAL RIVER SUSPENDED SOLIDS CONTENT	MAXIMUM PLANT USAGE (3) (CU. FT./SEC.)	MAXIMUM PLANT USAGE (3) (% OF TOTAL FLOW)	NORMAL PLANT USAGE (4) (CU. FT./SEC.)	NORMAL PLANT USAGE (4) (% OF TOTAL FLOW)
Design Minimum (2) (Feb.)	3,410	200 ppm	83.1	2.44%	17.5	0.51%
Annual Mean Flow	23,100	200 ppm	83.1	0.36%	17.5	0.08%
Typical Breakup (June-July)	150,000	2,250 ppm	83.1	0.06%	17.5	0.01%

(1) Samples were collected for the Alberta Research Council between September 1957 and September 1958. Analyses by the provincial analyst, Edmonton.

(2) Low Flow at station No. 07DA001 on the Athbasca River below Fort McMurray, which occurred in 1964 (Data available from 1958 to 1972).

(3) First year.

(4) Will be diminished by surface and subsurface water on the lease.

TABLE J

TABLE K

TAILINGS POND WATER BALANCE

	WATER (TONS/DAY)
STREAMS IN	
Extraction Tailings	168,700
Centrifuging Tailings	9,900
Mine Drainage Water(1)	10,800
Process Water from Upgrading Plant	20,000
Rainfall(2)	57,200
Total	266,600
STREAMS OUT	
Water in Sand Voids	53,000
Evaporation(3)	31,300
Water in Colloidal Suspension	47,800
Recycle	123,500
Percolation	11,000
Total	266,600

(1) 1500 IGPM.

(2) Based on 6 Square Miles of pond plus 10 Square Miles of mine and plant site - annual rainfall 17.7".

(3) Based on 6 Square Miles of pond - annual evaporation 25.2".

(4) Based on 0.00017"/Sq. Ft./Day filtration.

TABLE L

UPGRADING MATERIAL BALANCE

	MB/CD	Mlb/CD
IN		
Bitumen Feed	121.4	42,933
Natural Gas		410
Water to H_2 Plant		2,758
H_2S ex Utility Plant		850
		46,951
OUT		
Synthetic Crude	100.0	30,677
Fuel to Utility Plant	24.7	9,973
Naphtha to Extraction	2.7	752
Sulphur Product		1,965
CO_2 Vent ex H_2 Plant		3,370
Other Vents (including S in Tail Gas)		214
		46,951

TABLE M

PLANT ENERGY BALANCE

	MLb/CD	LOWER HEATING VALUE BTU/Lb	MMMBTU/CD
IN			
Bitumen Feed to Extraction	46,868	16,830	789
Natural Gas	410	21,502	9
			798
OUT			
Bitumen Loss in Extraction	3,934	16,830	66
Naphtha Loss in Extraction	752	18,630	14
Synthetic Crude	30,677	18,210	559
Product Sulphur	1,965	4,000	8
Heat Rejected (by difference)			151
			798

TABLE N

UPGRADING/UTILITIES SULPHUR BALANCE

	MLb/CD	LT/CD
SULPHUR IN		
Bitumen Feed to Upgrading	2,198	981
SULPHUR OUT		
Synthetic Crude	114	51
Released from Stacks		
ex Sulphur Plant	103	46
ex heaters and boilers	16	7
Product Sulphur	1,965	877
	2,198	981

TABLE O

PROFITABILITY SUMMARY

Project Size - MB/D Sales	100
Project Life - Onstream	25 years
Start of Construction	1-1-76
Onstream Date	1-1-80

Undeferred Values - $ MM	1973 Dollars	Escalated Dollars
Gross Revenue	3,100	8,650
Less Operating Costs Including Royalty	1,330	3,020
Operating Net Income	1,770	5,630
Less Ultimate Capital	760	1,040
Profit (Before Income Taxes)	1,010	4,590
Present Value at 10% to 1-1-73 - $ MM		
Profit (Before Income Taxes)	-100	+260
Earning Power Before Income Taxes - %	7	13
Payout from Start of Production - yrs.	11.0	7.9

5.0 FINDINGS

5.1 The Application to Amend the Process Plant Approval

The Board having publicly heard the application for the amendment of Approval No. 1725 under Part 8 of The Oil and Gas Conservation Act, of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, and having studied the evidence submitted by the applicants at the public hearing, and having regard to the advice of its staff and to its own knowledge finds as follows:

1. THE CONSERVATION AND TECHNICAL ASPECTS

The applicants propose major technical changes in the extraction and upgrading processes for the plant which have a substantial effect on the recovery efficiency of the total scheme. These changes, combined with a revised mining study, result in an overall scheme recovery efficiency of 56 per cent by weight compared with the 62 per cent proposed in 1971. The Board accepts that changes in the extraction and upgrading processes are required on the basis of the applicants pilot testing and considers the revised recovery efficiency as being satisfactory for the recovery scheme.

2. DEVELOPMENT SCHEDULE

The applicants propose a development schedule which would result in commencement of production between January 1, 1977 and January 1, 1978. The Board considers that the revised development schedule proposed by the applicants is realistic having regard for the date of commitment for the project, equipment delivery times and construction labor availability.

3. ENVIRONMENTAL PROTECTION

The proposed modifications to the recovery scheme would result in a significant reduction in the emission of sulphur to the atmosphere. The designed ground level concentrations of sulphur dioxide are well below the previously authorized Provincial standards and the applicants are prepared to limit the emission of particulate matter to conform to the Provincial standards. Control of process water streams has been designed to prevent any process water from entering the area watershed. Studies are being conducted by the applicants to determine the best method for reclamation of the area subsequent to the mining operation.

The Board considers that adequate provision has been made for environmental protection and the monitoring of effluent streams from the plant.

5.2 Application for Power Plant Approval

The Board having publicly heard the application of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for approval of the construction and operation of a power plant under section 7.2 of The Hydro and Electric Energy Act and having studied the evidence submitted by Syncrude at the hearing on behalf of the applicants, hereby finds as follows:

1. THE NEED FOR A POWER PLANT AND THE SUITABILITY OF ITS CAPACITY

The applicants propose to build an integrated power plant at the Mildred Lake Project to supply steam, hot water, and electric energy to the process plant. The Board agrees that an on-site power plant would in this case provide thermal and electric energy for the site in the most reliable and economic manner and is satisfied that a plant of 195 megawatts, in conjunction with an interconnection to the Provincial interconnected electric system, will be adequate.

2. RELATION OF THE POWER PLANT TO THE PROVINCIAL INTERCONNECTED ELECTRIC SYSTEM

The Board recognizes the benefits of a power plant at Mildred Lake and of the proposed interconnection with the Provincial electric system which would serve the applicants' plant and possibly the Fort McMurray area. The Board agrees that an interconnection to the Mildred Lake power plant is required but is of the view that the applicants should be prepared to accept the responsibility for any adverse effects which the proposed interconnection may have on the Provincial system. The Board approves of the concept of an interconnection subject to the completion of acceptable studies to confirm that the cyclic load imposed on the Provincial system will not have any adverse effects and subject to potential communication interference problems being resolved with the Alberta Government Telephones. The transmission line is the subject of a separate application scheduled for a public hearing in Edmonton on September 11, 1973.

3. THE POWER PLANT FUEL

The Board is satisfied that the applicants have adequately considered the use of the bitumen coke by-product from the process as a source of power plant fuel and the Board concludes that for technical, economic, or environmental reasons it would not be in the public interest to require coke to be burned in the power plant. The Board is therefore prepared to approve the use of process fuel gas, supplemented by natural

gas, as a power plant fuel subject to the applicants reporting to the Board on the future potential of producing synthetic gas from coke for use within the project or as a saleable product, and on the feasibility of using coke in a power plant which would serve the Provincial interconnected electric system.

4. THE ENERGY CONVERSION AND UTILIZATION EFFICIENCY

The applicants have, by the use of a combined gas turbine-steam turbine cycle, which would provide turbine exhaust steam to the process plant, proposed a power plant capable of achieving electric energy conversion efficiencies somewhat better than larger conventional power plants, and the Board is satisfied that the power plant can be designed to achieve a conversion efficiency which is representative of current power plant technology.

5. ENVIRONMENTAL IMPACT OF THE POWER PLANT

The power plant would not release any liquid effluents to natural bodies of water and would discharge its gaseous emissions through the same stack as the process exhaust gases such that the combined ground level concentrations would be within the required ambient air quality standards. The Board is satisfied that the applicants have taken satisfactory measures to control the power plant's possible environmental impact.

6.0 DECISION

6.1 Process Plant Application

Having regard for its findings and its responsibilities under The Oil and Gas Conservation Act and the Oil Sands Development Policy of the Government of Alberta, the Board is prepared, with the approval of the Lieutenant Governor in Council to grant the application and to issue to the applicants an approval superseding Approval No. 1725.

The approval would be in the form set out in Appendix B and subject to the terms and conditions therein contained.

6.2 Power Plant Application

Having regard for its findings and its responsibilities under The Hydro and Electric Energy Act, the Board is prepared, subject to the authorization of the Lieutenant Governor in Council pursuant to section 7.2 of the said Act, to issue to the applicants an approval for the construction and operation of a power plant at the Mildred Lake oil sands project.

The approval would be in the form set out in Appendix C and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

D. R. Craig, P. Eng.
Vice Chairman

J. I. Strong, P. Eng.
Board Member

DATED at Calgary, Alberta
this 10th day of September 1973

APPENDIX B

FORM OF APPROVAL

THE PROVINCE OF ALBERTA

THE OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the recovery of oil sands, crude bitumen or products derived therefrom

APPROVAL NO. 1920

WHEREAS the Energy Resources Conservation Board, by Approval No. 1725, dated February 28, 1973, approved a scheme of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the recovery of oil sands, crude bitumen or products derived therefrom, and

WHEREAS Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited have applied for amendment of the said Approval and it is proper and desirable that a new approval be issued superseding Approval No. 1725, and

WHEREAS the Energy Resources Conservation Board is prepared to grant the application by Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, subject to the conditions herein contained and each of the Minister of the Environment and the Minister of Lands and Forests has given his approval, hereto attached, insofar as the application affects matters of the environment.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970, and with the approval of the Lieutenant

Governor in Council numbered O.C. _______ and dated ________ __, 197_, and granted subject to certain further conditions therein set out, hereby orders as follows:

1. (1) The scheme of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited, proposed to be developed and operated on their behalf by Syncrude Canada Ltd. (which five companies are hereinafter collectively called "Syncrude") for the recovery of oil sands, crude bitumen or products derived therefrom, taken from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such scheme is described in

(a) an application dated May 9, 1962, as amended to May 3, 1968 and to March 24, 1969 and to August 7, 1971, and supporting material marked as exhibits and evidence adduced at the hearings of the application and amendments thereof, and

(b) an application dated March 5, 1973, and supporting material marked as exhibits and evidence adduced at the hearing of the application,

is approved, subject to the terms and conditions herein contained.

(2) Subclause (1) does not preclude alterations in design or equipment compatible with the outlines of the scheme and made for the better operation of the scheme.

2. This approval applies to recovery in each calendar year of 45,625,000 barrels of synthetic crude oil, but for the period consisting of the part of the year following the date, as established by the Board, of commencement of essentially full-scale operations, and the next succeeding calendar year, the above volumes shall be increased by multiplication by the factor equivalent to the number of days in the period divided by 365.

3. Prior to the commencement of major construction of the project facilities, Syncrude shall

(a) satisfy the Board that it would be economically feasible to remove and satisfactorily dispose of the tailings and overburden from the initial tailings disposal area described in the application referred to in clause 1, subclause (1), paragraph (a), in order that satisfactory recovery of the oil sands reserves of the area would ultimately be possible, or

(b) propose alternative or modified initial tailings disposal arrangements satisfactory to the Board such that the impairment of recovery of oil sands reserves would be minimized.

4. Prior to the commencement of major construction Syncrude shall, in the month of December of each year, through a brief report of the progress of its experimental, pilot plant and engineering design work, satisfy the Board that it is proceeding generally in accordance with the schedule submitted to the Board at the April 1973 hearing of the application referred to in clause 1, subclause (1), paragraph (b).

5. Syncrude shall satisfy the Board, prior to June 1, 1974, that construction of the facilities required for the scheme has commenced, unless upon application by Syncrude a later date is stipulated by the Board.

6. During construction of the proposed facilities Syncrude shall inform the Board on a quarterly basis of the progress of construction and shall obtain the approval of the Board concerning any major changes in design.

7. (1) Upon completion of the construction of the facilities and prior to June 1, 1976, or such later date as the Board may stipulate, Syncrude shall file such details of the project design or operating procedures as the Board may require.

(2) Without derogating from the generality of subsection (1), one year prior to the commencement of mining, and thereafter as required, Syncrude shall satisfy the Board and other concerned Departments and agencies of the Government of Alberta in detail as to the methods by which restoration of surface and revegetation will be done in mined out areas.

8. The effective commencement of the recovery of saleable hydrocarbon products shall be not earlier than January 1, 1977, and not later than January 1, 1978, unless upon application by Syncrude later dates are stipulated by the Board.

9. Syncrude shall measure materials mined and processed, intermediate and final products recovered and other plant streams as necessary, so that material balance and recovery calculations for the extraction, upgrading and related processes may be made with reasonable accuracy and frequency.

10. Syncrude shall furnish to the Board, in such detail and at such times as may be set by the Board

(a) monthly reports of the quantity and assay of oil sands mined and the quantity of all intermediate and final products recovered therefrom, and

(b) monthly sulphur balance reports for sulphur recovery plant.

11. After the commencement of mining operations, Syncrude shall report, in the first three years on a semi-annual basis and thereafter as required by the Board, the percentage of the crude bitumen in place in the mined area recovered during the report period, and details of the proposed mining and overburden removal plans for the succeeding period.

12. There shall be no flaring or waste of liquid hydrocarbons produced except in cases of emergency, unless authorized in writing by the Board and the Department of the Environment.

13. Syncrude shall carry out its operations to the satisfaction of the Board and in a manner that

(a) does not preclude or render more difficult the recovery of other oil sands recoverable by practical and reasonable operations,

(b) results in the mining of the practical maximum of all oil sands within the area being mined,

(c) results in the processing for the recovery of crude bitumen of the practical maximum of all oil sands mined,

(d) results in the recovery of the practical maximum of crude bitumen from the oil sands mined,

(e) results in the recovery from the crude bitumen of the practical maximum of marketable products,

(f) results in the production of the practical minimum amount of coke, and

(g) results in the recovery in the form of elemental sulphur not less than 95.0 per cent of the sulphur contained in the raw gas delivered to the sulphur recovery plant during each three month period commencing January 1, April 1, July 1, or October 1.

14. Syncrude shall carry out the solids disposal operations to the satisfaction of the Board and the Department of the Environment, on lands to be approved by the Board, and in a manner that ensures the stability of any tailings piles.

15. Syncrude shall dispose of any liquid wastes in a manner satisfactory to the Department of the Environment and the Board and in a manner that ensures that no oily or contaminative materials flow over the land or into any body of water, except as specifically provided for in the scheme as described in the applications referred to in clause 1, subclause (1).

16. (1) The emission of sulphur dioxide, and the sulphur dioxide equivalent of other sulphur compounds, to the atmosphere from the plant incinerator and boiler stack shall not exceed 287 long tons per day (143 long tons per day equivalent sulphur) or 8.1 long tons in any half-hour period (4.05 long tons equivalent sulphur).

(2) The plant incinerator and boiler stack height shall be sufficient to maintain the ambient maximum half-hour average ground level concentrations of sulphur dioxide within the standard prescribed for gas processing plants in the Oil and Gas Conservation Regulations and prescribed by The Clean Air Act and shall be a minimum of 600 feet.

(3) The plant incinerator and boiler stack flue gas emission temperature shall be a minimum of 450 degrees Fahrenheit.

(4) The concentration of particulates in the effluent gas from the plant incinerator and boiler stack shall not exceed the allowable limits as specified in the regulations for the control of air pollution of the Department of the Environment.

17. (1) In the event of an emergency necessitating the flaring of sour gas or sour gaseous products of the process, Syncrude shall add sufficient fuel gas to the sour gas or products prior to the flaring to ensure complete combustion and to maintain the maximum half-hour average concentration of sulphur dioxide within the standard prescribed by the Department of the Environment.

(2) The stacks for the flaring of sour gas, gaseous products of the process and hydrocarbon shall be of a height satisfactory to the Board and the Department of the Environment and shall be equipped with a continuously burning pilot and an automatic flame igniter.

18. (1) Syncrude shall conduct at suitable time intervals eight stack surveys per year for the determination of the volume rate of flow, concentration of particulates, composition and temperature of the effluent gases from the plant incinerator and boiler stack.

(2) In each year at least two of the stack samplings tests required by subclause (1) shall be made when the plant is operating at not less than 90 percent of its maximum daily production rate, and at least three others of such tests shall be made when the plant is operating at not less than 75 per cent of its maximum daily production rate.

19. (1) Syncrude shall maintain a network of static exposure cylinder stations for the detection of hydrogen sulphide and total sulphation in the plant vicinity to the satisfaction of the Department of the Environment.

(2) Syncrude shall maintain a monitoring program to provide a continuous record of atmospheric sulphur dioxide concentration to the satisfaction of the Department of the Environment.

20. Syncrude shall summarize the results of all stack surveys and the results of the observations required by clause 19 and forward them to the Department of the Environment and the Board as soon as they are, or can be made, available.

21. Syncrude, in operations pursuant to the scheme, shall comply with the provisions of any applicable Act or regulation of the Province of Alberta now enacted or made, or that any time hereafter may be enacted or made.

22. Where it appears to the Board that there has been a failure to comply with any terms or conditions of this approval, the Board may, in addition to any other remedy or proceeding to which it may resort, require the suspension of any operation carried on pursuant to the scheme.

23. Syncrude shall comply with The Clean Water Act Permit No. 73-WP-038 dated July 12, 1973, The Clean Air Act Permit No. 73-AP-054 dated July 12, 1973, or any subsequent revisions thereto, issued by the Department of the Environment.

24. This approval expires on December 31, 2001, unless rescinded before that date or unless the term of the approval is extended following a public hearing.

25. Board Approval No. 1725 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this ____ day of ____________, 1973.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

APPENDIX C

FORM OF APPROVAL

THE PROVINCE OF ALBERTA

THE HYDRO AND ELECTRIC ENERGY ACT

ENERGY RESOURCES CONSERVATION BOARD

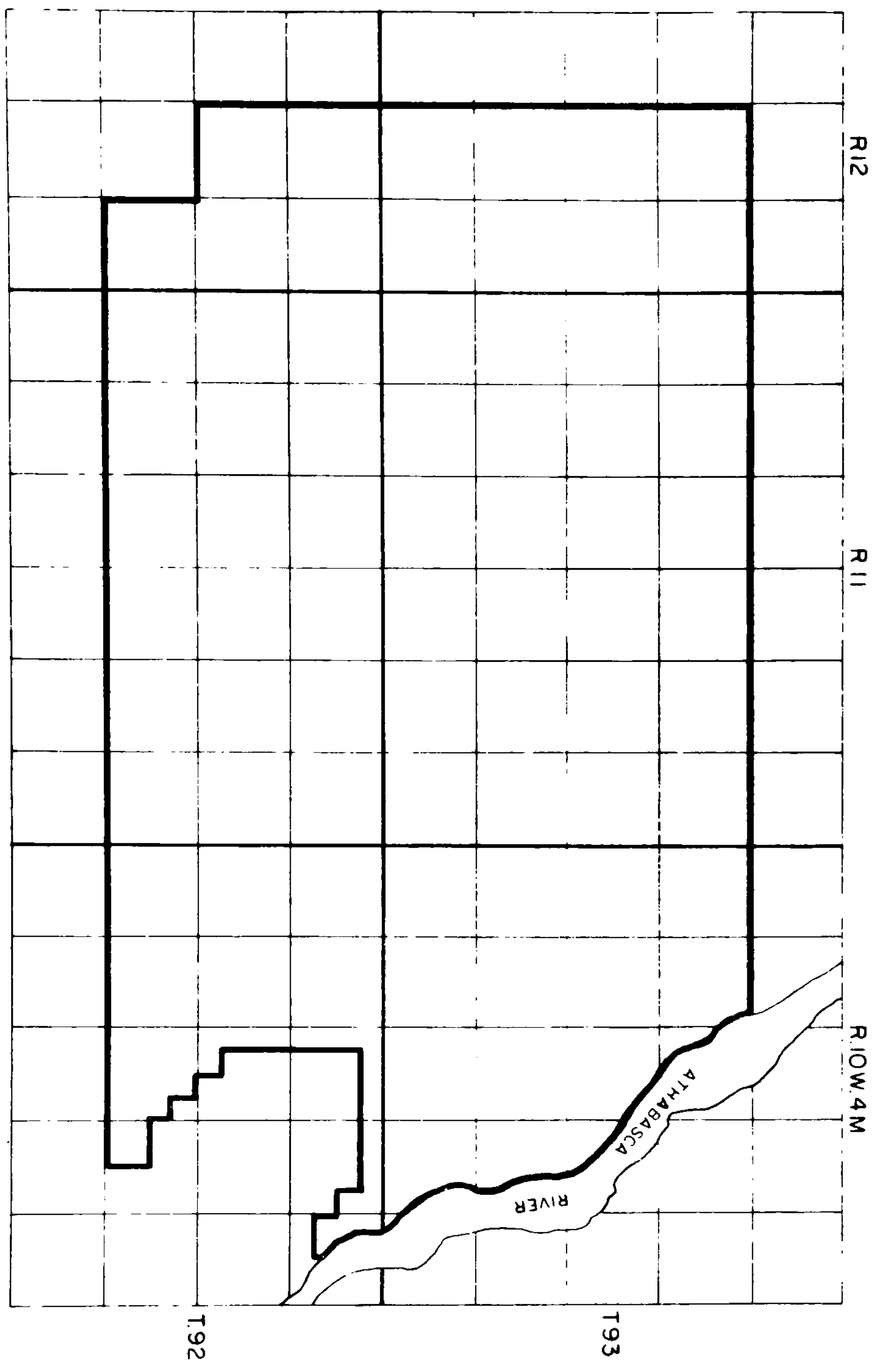
IN THE MATTER of the Mildred Lake power plant of Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited, and Imperial Oil Limited

APPROVAL NO. HE 7313

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited and Imperial Oil Limited for the construction and operation of a power plant, subject to the conditions herein contained, and the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment.

THEREFORE the Energy Resources Conservation Board, pursuant to The Hydro and Electric Energy Act, being chapter 49 of the Statutes of Alberta, 1971, and the Lieutenant Governor in Council having given his authorization by Order in Council, numbered O.C. _______ and dated ___________, 197_, hereby orders as follows:

1. The construction and operation by Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited, and Imperial Oil Limited, (hereinafter called "the Operators") of a power plant located in Section 6, Township 93, Range 10, West of the 4th Meridian, and the later operation of the said power plant by such other operator as the Board may stipulate, is approved, subject to the terms and conditions herein contained.



APPENDIX A TO APPROVAL NO. 1920

2. Subject to the other provisions of this Approval the power plant shall be in accordance with an application by Atlantic Richfield Canada Ltd., Canada-Cities Service, Ltd., Gulf Oil Canada Limited, and Imperial Oil Limited, to the Energy Resources Conservation Board, dated March 5, 1973, and evidence given in support of the application at a hearing on April 10, 1973.

3. The Operators shall satisfy the Board, by June 1, 1974, or by such later date as the Board may stipulate, that the design and operation of the on-site power plant and any equipment at the Mildred Lake Project, will not adversely effect the Provincial interconnected electric system.

4. The Operators shall satisfy the Board that adequate consideration has been given to the design and specification of all equipment for the Mildred Lake Project so as to minimize potential communication problems.

5. The Operators shall design and construct the Mildred Lake Project so as to provide for the possible future installation of facilities to utilize bitumen coke for the production of synthetic gas.

6. The Operators shall satisfy the Board by July 1, 1978, or by such later date as the Board may stipulate, as to the technical and economic suitability, and the environmental impact, of installing facilities at the Mildred Lake Project to make the maximum possible use of bitumen coke in the production of synthetic gas for use as a fuel or feedstock within the project, or as a saleable product from the project.

7. The Operators shall study, in consultation with the Electric Utility Planning Council, the technical and economic suitability, and the environmental impact, of transporting bitumen coke from the Mildred Lake Project for use as a fuel in a conventional power plant to serve

the Provincial interconnected electric system and shall report the results of the study to the Board by July 1, 1975, or by such later date as the Board may stipulate.

8. The Operators shall construct the Mildred Lake power plant so as to satisfy the terms and conditions of The Clean Air Act Permit No. 73-AP-054 and The Clean Water Act Permit No. 73-WP-038, or any subsequent revisions thereto, issued by the Department of the Environment in accordance with The Clean Air Act and The Clean Water Act.

9. The Operators shall monitor and report on the discharge rates and ambient concentrations of the gaseous, liquid and solid effluents resulting from the operation of the Mildred Lake power plant, to the satisfaction of the Department of the Environment and to the satisfactio of the Board as it may, from time to time, specify.

10. The Board at any time,

(a) upon its own motion or the request of the Department of the Environment, or

(b) upon the application of an interested person

may vary the terms and conditions hereof or rescind this approval.

MADE at the City of Calgary in the Province of Alberta, this ____ day of ________, 1973.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

MINES AND MINERALS

Office of
the Minister

403/229-3214

407 Legislative Building
Edmonton, Alberta, Canada T5K 2B6

September 14, 1973

Imperial Oil Limited
500 Sixth Avenue S.W.
CALGARY, Alberta
T2P 0S1

Atlantic Richfield Canada Ltd.
650 Guinness House
CALGARY, Alberta
T2P 0Z6

Canada-Cities Service, Ltd.
1100, 550 - 6th Avenue S.W.
CALGARY, Alberta
T2P 2M7

Gulf Oil Canada Limited
707 - 7th Avenue S.W.
CALGARY, Alberta
T2P 2H7

Dear Sirs:

Re: Syncrude Project

Reference is made to the recent discussions concerning the above project between representatives of Her Majesty the Queen in the Right of the Province of Alberta ("Her Majesty"), Imperial Oil Limited ("Imperial"), Canada-Cities Service, Ltd. ("Cities"), Atlantic Richfield Canada Ltd. ("ArCan") and Gulf Oil Canada Limited ("Gulf") (Imperial, Cities, ArCan and Gulf are herein jointly called the "Lessees"). As a result of these discussions agreement in principle has been reached concerning certain matters respecting the Syncrude project, including the initial royalty to be paid unto Her Majesty, rights of residents of Alberta to acquire interests in the Syncrude project and

related facilities, conditions concerning renewals of leases and the Lessees' commitment to proceed with the Syncrude project.

Her Majesty understands that the Lessees have agreed to proceed with the Syncrude project on the following understandings:

A. INTERPRETATION

1. In this letter:

(a) "Accounting Manual" shall mean the Accounting Manual to be annexed to the Definitive Agreement;

(b) "capital costs" shall mean the capital costs determined in accordance with the provisions of the Accounting Manual incurred by the Lessees on the Syncrude project (other than working capital employed therein) after February 23, 1972;

(c) "Definitive Agreement" shall mean the agreement to be hereafter prepared and executed between the parties to this letter setting out in definitive terms the general understandings contained in this letter;

(d) "Syncrude" shall mean Syncrude Canada Ltd., a company incorporated under the laws of the Province of Alberta;

(e) "Syncrude project" shall mean the project approved in Approval No. 1725 of the Energy Resources Conservation Board, as such project may be amended from time to time by any approval hereafter issued in substitution therefor or amendment thereof under The Oil and Gas Conservation Act with the approval of the Lieutenant Governor in Council; excluding however the utilities plant and the synthetic crude pipeline both as hereinafter defined;

(f) "synthetic crude pipeline" shall mean the pipeline or pipelines hereafter constructed, together with all land and facilities acquired or constructed in connection therewith, primarily for the purpose of transporting crude oil from the Syncrude project to Edmonton, Alberta;

(g) "the leased substances" shall mean all substances which the Lessees have the right to recover pursuant to the leases, or any of such substances;

(h) "the leases" shall mean Government of Alberta Bituminous Sands Lease No. 17, together with any other documents of title issued in substitution therefor;

(i) "utilities plant" shall mean the utilities plant approved in draft Approval No. HE 7313 of the Energy Resources Conservation Board, as such Approval may be hereafter amended from time to time under The Hydro and Electric Energy Act with the approval of the Lieutenant Governor in Council;

(j) "date of start of production" shall mean the first date after the Syncrude project has produced an aggregate of 5,000,000 barrels of synthetic crude oil;

(k) "year" shall mean a calendar year.

B. APPROVAL OF THE SYNCRUDE PROJECT

2. The Lessees acknowledge that Order in Council 244/72, as amended by Order in Council 1337/73, approved the Energy Resources Conservation Board's amendment of its approval of the Syncrude project subject to the following conditions:

(a) that the Lessees will grant to Canadian citizens who are residents of the Province of Alberta an opportunity to purchase an equity in the Syncrude project to be operated by Syncrude, the nature, method of allocation and distribution of the equity to be subject to the approval of the Government of Alberta;

(b) that there will be a director of the company incorporated to issue the said equity, a Canadian citizen resident in Alberta whose appointment shall be effective only upon the prior approval of the Government of Alberta;

(c) that the Lessees shall give in writing prior to September 17, 1973, to the Government of Alberta a firm commitment to proceed with the Syncrude project;

(d) that the Lessees undertake in connection with the Syncrude project wherever practical and reasonable

(i) to use the engineering services of firms or companies whose personnel are residents of Alberta;

(ii) to use construction firms owned by residents of Alberta;

(iii) to purchase equipment and supplies manufactured in Alberta;

(iv) to employ residents of Alberta;

and the Lessees will, from time to time, but not less than once every three months, submit to the Government of Alberta a report with respect to items (i), (ii), (iii) and (iv) above, with such explanation as the Government of Alberta may require;

(e) that insofar as it is reasonable to do so, the Lessees will ensure that the production, processing and manufacture of by-products developed from the operation of the Syncrude project will be carried out in the Province of Alberta.

3. The Lessees hereby commit to proceed with the Syncrude project, subject to the provisions hereof, and agree to comply with the other conditions of Order in Council 244/72, as so amended. Her Majesty agrees that this commitment to proceed satisfies the third condition of the said Order in Council, as so amended.

4. Each of the Lessees hereby covenants and agrees that it shall not mine, produce or process the leased substances except in accordance with the provisions of Approval No. 1725 of the Energy Resources Conservation Board, as such Approval may be hereafter amended from time to time under The Oil and Gas Conservation Act with the approval of the Lieutenant Governor in Council.

C. PROVISIONS CONCERNING ROYALTY

5. The royalty to be rendered and paid to Her Majesty pursuant to the leases during the term of these provisions shall be a portion of all leased substances derived from the leased lands calculated as hereinafter provided. It is agreed that such royalty portion is and always has been reserved to Her Majesty. The amount of the royalty shall be determined each year after the date of start of production and shall be that percentage of all leased substances recovered in the Syncrude project which are sold or otherwise disposed of during such year (excluding operating and utility fuel requirements and losses of the Syncrude project and the utility plant) and which have an aggregate value equal to 50% of the excess of gross revenue over expenses of the Syncrude project for that year. That excess shall be determined each year after the date of start of production by deducting from the gross revenue of the Syncrude project from all sales or other dispositions (valued at the plant gate at the time of sale or other disposition) during such year the following costs and expenses:

(a) allowed operating costs incurred during such year (which costs shall not include income tax);

(b) amortization of all capital costs (except working capital) of the Syncrude project incurred after February 23, 1972 on a straight-line basis as follows:

(i) all capital costs incurred on or before the beginning of the fifth anniversary of the date of start of production shall be amortized over an assumed life of 20 years commencing on the fifth anniversary of the date of start of production;

(ii) all capital costs incurred after the fifth anniversary of the date of start of production shall be amortized over an assumed life commencing on the date such costs were incurred and ending on the 25th anniversary of the date of start of production;

except that if the date of start of production or the date a capital cost was incurred (as the case may be) is not the first day of a year then:

(A) the capital costs which may be amortized during the balance of the year after the fifth anniversary of the date of start of production, or the date such capital cost was incurred, shall only be that fraction of the capital costs which could be amortized during such year, if it were a

full year, which is equal to the fraction which the number of days in such year after the fifth anniversary of the date of start of production, or the date such capital cost was incurred, bears to 365, and

(B) during the final year in which capital costs may be amortized, capital costs may be amortized for that number of days in such final year up to the 25th anniversary of the date of start of production;

and provided further that in computing capital costs simple interest at the rate of 8% per annum may be charged up to the date of start of production on costs of construction incurred between September 1, 1973 and the date of start of production providing that the total amount of such interest charges shall not exceed $90,000,000;

(c) deemed interest expense (in lieu of actual interest charges) at the rate of 8% per annum of 75% of the average capital (including working capital but excluding any interest on costs of construction permitted pursuant to sub-paragraph (b) above) employed during such year reducing such capital (other than working capital) on a straight-line basis as follows:

(i) capital employed at the date of start of production shall be amortized over an assumed life of 25 years from the date of start of production;

(ii) additional capital employed after the date of start of production shall be amortized over an assumed life commencing on the date of employment of such capital and ending on the 25th anniversary of the date of start of production.

Gross revenue, the costs and expenses which may be deducted therefrom, and capital costs shall be calculated in accordance with the provisions of the Accounting Manual. In computing such gross revenue, costs and expenses, no revenue shall be included from the sale or other disposition of technology or assets developed or acquired by the Lessees prior to February 23, 1972 and no charge shall be made for the use of such technology or assets. Any income earned from the Syncrude project prior to the date of start of production shall be deducted in computing costs incurred prior to the date of start of production. Any amount received from the sale or other disposition of material and equipment in the Syncrude project shall be deducted in computing capital costs.

Leased substances recovered in the Syncrude project which are stored on the project site shall not be included in the above calculations until they are sold or otherwise disposed of.

If the sum of the deductions permitted by subparagraphs (a), (b) and (c) hereof during any year exceeds the gross revenue for such year the amount of such excess shall be carried forward cumulatively and allowed as an

operating cost in computing the excess of gross revenue over expenses of the Syncrude project during succeeding years.

6. Within 15 days after the end of each month of each year Syncrude shall make a good faith estimate in accordance with the Accounting Manual of the amount of royalty payable with respect to the Syncrude project for such year. The Lessees shall cause Her Majesty to be advised in writing of the amount of such estimated royalty within such 15-day period and at the same time shall pay Her Majesty a royalty instalment in an amount equal to 1/12th of such estimated royalty. The total of the royalty instalments paid in respect of such year shall be adjusted within 90 days after the end of the year in accordance with the actual royalty payable with respect to the Syncrude project for the year as verified by audited financial statements (which shall be supplied to Her Majesty) of the royalty payable for such year. Such financial statements shall include details of the calculation of such royalty and an auditor's certificate as to such calculation.

7. (a) Representatives of Her Majesty shall have access at all reasonable times to all information, data, contracts and agreements relating to the Syncrude project, the utilities

plant and the synthetic crude oil pipeline that the Lessees are entitled to disclose, including, without limitation, information, data, contracts and agreements relating to:

(i) the design, engineering, construction or operation of the Syncrude project, the utilities plant and the synthetic crude pipeline,or any of them,

(ii) the purchase or other acquisition of materials and supplies for the Syncrude project, the utilities plant and the synthetic crude pipeline, or any of them, and

(iii) the sale or other disposition of leased substances from the Syncrude project.

All such information, data, contracts and agreements shall at all times be kept secret and confidential and the Definitive Agreement shall set out appropriate confidentiality requirements for the representatives of Her Majesty.

(b) From and after the date of this letter representatives of Her Majesty,

(i) shall have the right to meet with the Lessees, or their representatives, once each month to be advised of such matters relating to the Syncrude project as Her Majesty may reasonably request, and shall receive notice of and have the right to attend all meetings of directors of Syncrude;

(ii) shall have the right from time to time to audit, at Her Majesty's expense, the past and current costs and expenses incurred or committed to be incurred with respect to the Syncrude project; and

(iii) shall be entitled to currently receive all data and information concerning the Syncrude project in order to keep Her Majesty fully informed of all matters relating to the Syncrude project.

(c) Her Majesty shall designate such representatives by notice in writing to Syncrude within 90 days after the date hereof, and shall have the right from time to time to change such representatives by a similar notice in writing.

(d) Neither Her Majesty, nor any of Her representatives, shall have any right to vote at any such meeting and shall not have the right to approve or disapprove any action or proposed action by any of the participants in the Syncrude project and shall not be liable for any costs, expenses or liabilities thereunder.

8. The Lessees shall cause Syncrude to give Her Majesty written notice of the date of start of production within 15 days after such date.

9. Notwithstanding the above, Her Majesty shall have the right at any one time after the fifth anniversary of the date of start of production to take Her royalty in an amount equal to 7½% of the total annual production of any and all of the leased substances recovered from the Syncrude project, excluding however leased substances (other than synthetic

crude oil) consumed in the operation of, or lost in, the Syncrude project or the utility plant. Her Majesty may exercise this right by delivering a notice in writing to that effect to Syncrude, whereupon this right shall be exercised as of the effective date specified in the notice (which shall not be earlier than the date of delivery of the notice) or the fifth anniversary of the date of start of production, whichever is the later. If Her Majesty exercises this right, the royalty payable pursuant to these royalty provisions shall, after the effective date of such exercise, be calculated pursuant to this clause instead of pursuant to clause 5 hereof.

10. Any sale of the leased substances, or any of them, until otherwise ordered by the Minister of Mines and Minerals, shall include the royalty share thereof belonging to Her Majesty. Her Majesty reserves the right to take Her royalty in kind at the plant gate by taking an amount of any and all of the leased substances recovered in the Syncrude project:

(a) having an aggregate fair market value for each year equivalent to the value of the royalty calculated in accordance with clause 5 hereof for such year,

or

(b) which during each year shall be equal to the royalty calculated in accordance with clause 9 hereof for such year,

whichever clause is then applicable.

If Her Majesty exercises the right to take Her royalty in kind pursuant to this clause 10, She shall be entitled to take in kind each month 1/12th of the total amount She would be entitled to take during such year, based where applicable upon the estimates referred to in clause 6, and subject to adjustment within 90 days after the end of such fiscal year in accordance with the actual royalty for such year as verified by the audited financial statements referred to in clause 6. If Her Majesty exercises the right to take in kind set forth in this clause, Her Majesty shall provide all tanks and other facilities required to take the production in kind.

11. In the event of the sale by the Lessees of the royalty share of the leased substances belonging to Her Majesty, the deductions that may be allowed for charges incurred in transporting such royalty share of the leased substances shall:

(i) in the case of synthetic crude oil transported in the synthetic crude pipeline, be the tariffs charged by such pipeline, and

(ii) in the case of other leased substances, be the reasonable deductions specified by the Minister of Mines and Minerals.

12. These provisions concerning royalty shall come into effect on the date hereof and shall remain in full force and effect until changed as hereinafter provided. Her Majesty shall have the right to change these royalty provisions at

any time after the tenth anniversary of the date of start of production. In addition, should substantial changes in circumstances occur which are not now reasonably within the contemplation of the parties hereto:

(a) Syncrude may request a review and change of these royalty provisions at any time thereafter, and

(b) Her Majesty may review and change these royalty provisions at any time after the fifth anniversary of the date of start of production.

Without restricting the generality of the foregoing, the parties hereto agree they anticipate that, within five years after the date of start of production, the Syncrude project will, over a six-month period, be producing synthetic crude oil at an average rate of at least 100,000 bbl/d.

13. Notwithstanding anything herein contained or implied to the contrary, these royalty provisions will be subject to review and revision in the event of changes in Federal Government policy or laws which could materially affect the position of Her Majesty or any of the other parties hereto.

14. The Minister of Mines and Minerals shall recommend to the Lieutenant Governor in Council that regulations be passed pursuant to section 174 of The Mines and Minerals Act prescribing the above royalty with respect to the leases.

D. ENVIRONMENTAL CONSIDERATIONS

15. Reference is made to the letter dated July 13, 1973 from the Minister of the Environment to the President of Syncrude concerning environmental matters relating to the Syncrude project. The Lessees agree to comply with the provisions of the said letter in their construction and operation of the Syncrude project. Her Majesty agrees that the commitment contained in paragraph 6 of the said letter is a commitment binding upon Her Majesty.

16. As required by sub-paragraph 5 (c) of the said letter, the Lessees agree to deposit with Her Majesty funds, or a bond acceptable to Her Majesty, in an amount sufficient to ensure to the satisfaction of Her Majesty proper reclamation of the lands involved in the Syncrude project. If, upon termination of the Syncrude project, the lands are reclaimed to the satisfaction of Her Majesty the said funds or bond shall be returned to, or to the order of, the Lessees. Otherwise, the said funds or bond shall be forfeited.

E. PUBLIC PARTICIPATION

17. (a) The Lessees hereby grant Her Majesty an irrevocable option to acquire an interest in the Syncrude project, including the project site, the leases and rights granted thereby, and all facilities acquired or constructed as part of the Syncrude project, which interest may be for an undivided percentage interest of not less than 5% and up to and including 20%.

(b) The above option may be exercised at any time during the period from the date hereof and up to and including that date which is six months after the date of start of production, or the 31st day of December, 1982, whichever is the earlier. If the option is exercised prior to the date of start of production the interest for which the option is exercised will be deemed to have been acquired as and from the date of delivery to Syncrude of the notice exercising the option. If the option is exercised on or after the date of start of production the interest for which the option is exercised will be deemed to have been acquired as and from the date of start of production.

(c) The option may be exercised by notice in writing to Syncrude delivered within the said period setting out the interest for which the option is exercised and within 60 days after delivery of such written notice the optionee will pay to the Lessees the cost of acquiring such interest, computed as hereinafter stated.

(d) If the option is exercised the optionee will pay, and the Lessees will receive as proceeds of disposition, an undivided percentage share of all costs (net of income) incurred in the Syncrude project after February 23, 1972 and up to the date from which the interest is acquired under the option equal to the percentage interest which the optionee elects to acquire, and the optionee shall become a full joint venture participant in the Syncrude project as and from such date. Such costs shall be computed in accordance with the Accounting

Manual and shall include interest (compounded anually) on such costs at 8% per annum. No portion of such costs shall be attributed to reserves of leased substances.

(e) Upon exercise of the said option the Lessees shall assign to the optionee, in proportion to their respective interests therein, the interest which the optionee has elected to acquire in the Syncrude project, including the project site, the leases and all rights granted thereby, and all facilities constructed in connection therewith, and an equal percentage share of all outstanding shares of Syncrude and the Lessees and the optionee shall execute a joint venture agreement, and the Lessees, the optionee and Syncrude shall execute an operating agreement (each such agreement to be in a form to be annexed to the Definitive Agreement) for the operation of the Syncrude project. Syncrude shall be the operator under such operating agreement. The optionee shall not acquire any ownership in the technology and assets developed or acquired by the Lessees prior to February 23, 1972.

(f) Her Majesty may assign all or any part of the option granted in this clause 17 to an entity or entities to be formed for the purpose of permitting the people of Alberta to participate, inter alia, in the Syncrude project. The word "optionee" herein shall mean Her Majesty and any entity or entities to which this option, or any part thereof, is assigned.

18. (a) The synthetic crude pipeline shall be constructed and owned as to an undivided 80% thereof by Her Majesty and/or

an entity or entities hereafter formed by Her Majesty for the purpose of permitting the people of Alberta to participate, inter alia, in the synthetic crude pipeline, and as to the remaining 20% thereof by the Lessees or their assignees in the respective undivided percentage interests in which the Lessees presently own the leases.

(b) Her Majesty and/or the entity or entities formed by Her Majesty and the Lessees shall execute an agreement (in a form to be annexed to the Definitive Agreement) providing for the design, construction and operation of the synthetic crude pipeline.

(c) Notwithstanding anything herein or in such agreement contained or implied to the contrary:

(i) each owner of an interest in the synthetic crude pipeline shall be obligated, but only to the extent of its equity interest therein, to execute such guarantees, stock subscription agreements or similar documents in aid of financing as may be required by lending institutions in any financing arrangements for the synthetic crude pipeline;

(ii) the Lessees and Her Majesty and their respective assignees of any interest in the Syncrude project will dedicate their respective shares of the synthetic crude oil recovered from the Syncrude project to the synthetic crude pipeline;

(iii) the pipeline tariff for synthetic crude oil from the Syncrude project shall be sufficient to cover

operating costs, interest on debt, recapture of capital (over the projected life of the Syncrude project) and a reasonable return, provided that if the capacity of the synthetic crude pipeline exceeds 125,000 bbls/d, the tariff charged for synthetic crude oil from the Syncrude project shall not exceed the amount which could reasonably be charged for the pipeline if its capacity were only 125,000 bbls/d.

19. Her Majesty, and/or an entity or entities hereinafter formed by Her Majesty for the purpose of permitting the people of Alberta to participate therein and other operations, shall have an undivided 50% interest in the utilities plant. The Lessees, or another corporation designated by them (if they desire to have another corporation construct and operate the utilities plant) shall own the remaining 50% interest in the utilities plant. The respective owners of the utilities plant, the Lessees and Syncrude, shall execute an agreement (in a form to be annexed to the Definitive Agreement) for the construction and operation of the utilities plant; which agreement shall, inter alia, ensure the owners of the utilities plant a reasonable return calculated on the basis of 75% debt and 25% equity and will provide for the utilities plant to be operated for the owners of the Syncrude project on a cost of service basis.

F. LEASE RENEWAL

20. The terms of those portions of the following Alberta Bituminous Sands Leases owned by the Lessees, namely Leases 22, 29, 31, 32, 40, 41 and 78, containing rights which in the opinion of the Minister lie within the mineable portion of the bituminous sands area shall be for an initial term of 21 years renewable as hereinafter prescribed:

(a) such portions of the said leases may be renewed at the end of the initial 21-year term in accordance with Alberta Regulation 130/69 provided that the lessees thereof have entered into exploration commitments satisfactory to the Minister designed to evaluate the economically extractable deposits of bituminous sands underlying such portions and the thickness and composition of associated overburden materials;

(b) work carried out prior to the date hereof shall at the discretion of such Minister be credited towards the lessee's exploration commitment for lease renewal;

(c) the exploration commitment shall be carried out in conformity of time schedules related to the expiry of the initial terms of the said leases, subject to the discretion of such Minister:

(i) at least six months prior to renewal of those leases expiring in 1975 to 1979 inclusive; and

(ii) by January 1, 1980 for those leases expiring in 1980 and later;

(d) the renewal shall otherwise be subject to the provisions of Alberta Regulation 130/69.

G. CONDITIONS

21. The agreement of Her Majesty and the Lessees is subject to the following conditions, namely:

(a) that such Syncrude contractors as Syncrude may request shall enter into a site agreement or agreements with labor organizations in a form which will have the effect of bringing the various trade components under one set of working conditions and which will achieve labor stability through to the completion of the project;

(b) that a Federal income tax ruling or other advice, satisfactory to her Majesty and the Lessees, be obtained on or before November 16, 1973 to the effect that either the royalty reserved by Her Majesty pursuant to the royalty provisions referred to herein will not be included in computing the income of the Lessees for Canadian income tax purposes, or payments of such royalty to Her Majesty will be a deductible expense of the Lessees in computing their income for Canadian income tax purposes; and, in any event, such royalty payments will not be considered to be taxes on income from mining operations which, after 1976, may not be deducted in computing income under the Canadian Income Tax Act;

(c) that the Federal Government does not regulate directly or indirectly the prices of synthetic crude oil below the levels attainable in a free international market.

H. <u>DEFINITIVE AGREEMENT</u>

22. Forthwith after the Lessees' approval of this letter a Definitive Agreement shall be prepared and executed between Her Majesty and the Lessees. The Definitive Agreement shall incorporate the general understandings contained herein and shall have annexed thereto the Accounting Manual and the forms of agreements referred to in clauses 17 (e), 18 (b) and 19 hereof for the construction and operation of the Syncrude project, the synthetic crude pipeline and the utilities plant.

If the Lessees agree with the above understandings, will each of the Lessees please execute and deliver all five

copies of this letter so that Her Majesty and each Lessee may have one fully executed copy thereof.

Your very truly,

Bill Dickie

Bill Dickie, Q.C.
Minister of Mines and Minerals

Agreed to this 14th day of September, 1973.

IMPERIAL OIL LIMITED

Per J. A. Cogan

ATLANTIC RICHFIELD CANADA LTD.

Per

CANADA-CITIES SERVICE, LTD.

Per

GULF OIL CANADA LIMITED

Per

FOSTER ECONOMIC CONSULTANTS LTD.

ROOM 400, 600 SIXTH AVENUE S.W., TELEPHONE 263-1790
CALGARY, ALBERTA T2P 0S5

PRINCIPAL RISK AREAS OF SYNCRUDE PROJECT

Prepared by

Foster Economic Consultants Ltd.

September, 1973

Tabled in the Alberta Legislature, October 10, 1973

Principal Risk Areas of Syncrude Project

1. Price

The economics of the Syncrude project are very sensitive to changes in the price received for the synthetic crude oil which will be produced. Since it is expected that the plant will be in operation for approximately 25 years, a project evaluation requires projection of crude prices over the 25 year period from commencement of production. In view of the current dynamic situation with crude oil prices, it is impossible to accurately forecast future price levels, even in the relatively near future. In addition to the international forces which will affect crude prices a further uncertainty is added through possible domestic price controls which could set prices below internationally established levels. Also, the development of other major energy sources (oil shales, liquefaction and gasification of coal, nuclear energy) could have a significant effect on crude oil prices.

2. Production Quotas

As with prices, it is very difficult to forecast the crude oil supply-demand picture for 25 years. Therefore, a risk element which must be considered is the possibility of controls which could limit production below plant capacity.

3. Technological - Mining

The mining component of an oil sands project is a very large one. The only existing operator, Great Canadian Oil Sands uses bucket wheel excavators as its principal mining equipment whereas Syncrude hopes to achieve some economies through the use of very large drag lines. The feasibility of drag line use has been under study through a test operation but has not been proven to be satisfactory. Syncrude agreed to proceed with its plant before it could finalize its mining programme and if drag lines cannot be used, it expects higher mining costs from the use of bucket wheels.

4. Technological - Scale

The Syncrude facility will be a very large one and some of the individual components will be the largest in use in the world. If a drag line mining scheme is utilized, the drag lines will be very large. The fluid cokers to be used in the processing plant are expected to be the largest in the world and numerous other components will be so large that there will be very few of similar scale in use. This results in risks due to the relatively unproven workability of very large individual components.

5. Technological - Climate

The Syncrude plant is located in a northern area subject to extremely cold weather. This can adversely affect the performance of equipment which functions satisfactorily under less severe climatic conditions.

6. Technological - Mechanical Failures

Because of the size and complexity of the Syncrude plant there is considerable risk of failures of individual components which could affect production volumes. To minimize this, Syncrude has designed its facility to have two trains with the hopes that should there be problems in one section of the plant, the remaining portion of the facility could continue in operation.

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7. Costs

The Syncrude project is being undertaken during a period of rapidly escalating construction costs. It is difficult to accurately project future rates of inflation and consequently the capital cost of the project is subject to some uncertainty.

8. Material and Equipment Supply

There is an unprecedented volume of major plant construction contracted and planned for North America in the next few years. This construction includes new refineries, refinery additions, nuclear energy plants, petro-chemical plants and similar major complexes. As a result there are indications that materials and equipment may be in short supply with resultant uncertainties as to deliverability and problems with quality. Short supply also is normally accompanied with escalation of prices.

9. Labour

A number of uncertainties face Syncrude with regard to labour. These affect the design and engineering of the facility, the construction of the plant and the staff to man the project once it commences operation. Syncrude has been surveying the labour market and has determined that the necessary supply of trained personnel is not available in Alberta and is probably not available in Canada. Because of the size of the project major programmes must be undertaken to recruit and train professionals, tradesman and operating personnel.

If satisfactory arrangements can be made with the various trade unions, such that Syncrude is not faced with work stoppages during construction, a significant risk element will be removed from the Syncrude project. However, if this cannot be done, there is a major risk to Syncrude since relatively short work stoppages at critical times could cause major delays in construction because of the seasonal factors affecting construction

10. Environmental Controls

While the plant will be constructed in accordance with environmental regulations now in effect, an oil sands operator faces the possibility that future controls of a more strict nature could significantly add to both capital and operating costs.

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CALCULATION OF ALBERTANS' SHARE

OF PROFITS

FROM SYNCRUDE PROJECT

Prepared by

FOSTER ECONOMIC CONSULTANTS LTD.

Tabled in the Alberta Legislature October 10, 1973

CALCULATION OF ALBERTANS' SHARE OF PROFITS FROM SYNCRUDE PROJECT

ROYALTY CALCULATION
(FIGURES IN MILLIONS OF DOLLARS UNLESS OTHERWISE NOTED)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Crude Price @ Plant Gate $/bbl.	4.85	5.10	5.35	5.60	5.85	6.15	6.45	6.75	7.10	7.45	7.85	8.25	8.65	9.05	9.50	10.00	10.50	11.05	11.60	12.15	12.75	13.40	14.10	14.80	15.55
Estimated production Mbbls/day	50	90	105	105	115	120	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Revenue	88.5	167.5	205.0	214.6	245.6	269.4	294.3	308.0	323.9	339.9	358.2	376.4	394.7	412.9	433.4	456.3	479.1	504.2	529.3	554.3	581.7	611.4	643.3	675.3	709.5
Less: Operating Costs	105.7	124.8	136.3	143.3	149.6	158.0	164.8	174.8	184.6	192.7	202.1	213.7	223.4	237.4	248.3	260.5	272.4	285.0	298.7	312.5	327.8	343.5	359.3	376.4	394.5
Amortization of Capital Costs						56.5	56.8	57.1	57.1	58.3	58.5	60.3	60.3	60.8	61.3	62.5	62.5	63.9	64.0	67.5	68.6	69.7	73.1	79.9	79.8
Interest Allowance	57.1	55.9	54.0	52.3	51.4	51.6	50.7	48.4	46.0	44.0	41.9	40.1	38.1	35.5	33.0	30.7	28.2	25.6	23.0	20.6	18.2	15.2	12.3	9.5	6.0
Total Allowed Costs	162.8	180.7	190.3	195.6	201.0	266.1	272.3	280.3	287.7	295.0	302.5	314.1	321.8	333.7	342.6	353.7	363.1	374.5	385.7	400.6	414.6	428.4	444.7	465.8	480.3
Profit (Loss)	(74.3)	(13.2)	14.7	19.0	44.6	3.3	22.0	27.7	36.2	44.9	55.7	62.3	72.9	79.2	90.8	102.6	116.0	129.7	143.6	153.7	167.1	183.0	198.6	209.5	229.2
Loss Carried Forward	74.3	87.5	72.8	53.8	9.2	5.9																			
Profits to be Shared							16.1	27.2	36.2	44.9	55.7	62.3	72.9	79.2	90.8	102.6	116.0	129.7	143.6	153.7	167.1	183.0	198.6	209.5	229.2
Royalty to Province (50%)							8.0	13.9	18.1	22.4	27.9	31.1	36.5	39.6	45.4	51.3	58.0	64.8	71.8	76.9	83.5	91.5	99.3	104.8	114.6

Notes

1. Crude prices projected by Foster Economic Consultants as at August 1, 1973.
2. Production rates, operating costs and capital costs were provided by Syncrude.
3. The Royalty formula of September 14 calls for the pre-production period to end when 5,000,000 barrels of production has been reached. This is projected by Syncrude to occur about January 1,1978. Prior to that period all revenues from crude sales are to be deducted from allowed capital costs (hence reducing the total capital cost figure to be amortized and the figure on which the interest allowance is calculated). The royalty calculation, for purposes of this illustration, was considered to commence January 1, 1978.
4. Capital costs included all Syncrude costs incurred after February 23, 1972. Therefore, the basic plant, with a capacity of 105,000 bbls/day is estimated to cost $980.2 million (inclusive of $33.7 million of working capital) and would have both trains completed in 1978. Capital additions of a further $263.8 million are projected over the estimated 25 year life of the plant, with the ultimate capacity of 125,000 bbls/day being reached in 1984.
5. The interest allowance is at the rate of 8% on 75% of capital employed. Capital employed does not include any interest costs during construction.
6. Amortized capital costs include all pre-production costs (net after deduction of pre-production revenue) and capital expenditures plus $90 million allowed for interest costs during construction(working capital is excluded.)

SUMMARY OF ECONOMICS FOR SYNCRUDE PLANT, PIPELINE & UTILITY PLANT
(FIGURES IN MILLIONS OF DOLLARS)

Project Life Profits - Oil Sands Plant					Project Life Profits to AEC					
Province (Royalty)	Syncrude (After Tax) (A)	AEC 20% Share of Syncrude	Syncrude Less AEC (2 - 3)	Province Plus AEC (1 + 3)	Pipe-Line(B)	Utility Plant (C)	Total Profits To Province And AEC (1 + 3 + 6 + 7)	Syncrude Oil Co. Participants' Profit on Pipeline (Total - AEC)	Syncrude Oil Co. Participants' Profit (Oil Sands & Pipeline) (4 + 9)	Province Royalty & AEC Share Oil Sands Plant + P/L ÷ Total Profits Excluding Utility Plant (1 + 3 + 6 ÷ 1 + 3 + 6 + 4 + 9)
1	2	3	4	5	6	7	8	9	10	11
1,060	1,475	295	1180	1355	250	30	1635	60	1240	56%

(A) For tax purposes, it is assumed Syncrude is a separate corporate entity.

(B) Assumes staged construction of a pipeline with ultimate capacity of 1,000,000 bbls/day. Pipeline details not finalized so profit estimate is approximate.

(C) Assumes 10% return on equity investment. Utility plant details not finalized so profit estimate is approximate.

CALCULATION OF ALBERTAS' SHARE (CONTINUED)

ROYALTY CALCULATIONS PER SEPTEMBER 14,1973 LETTER OF INTENT

DEPRECIATION SCHEDULE

Total Syncrude Costs as of December 31,1977 (from Feb.23/72)	$957.2 million
Less working Capital of $33.7 million	923.5 million
Plus allowed construction interest of $90 million	1,013.5 million
Less pre-production revenue (1977 crude sales of $21.8million)	991.7 million

Total capital costs eligible for depreciation in royalty formula as of December 31,1977 = $991.7 million

	Depreciable Total Beginning of Year	Additions	End of Year (Before Dep'n)	Depreciation Fraction	$
1978	991.7	30.9	1,022.6		
1979	1,022.6	5.8	1,028.4		
1980	1,028.4	6.4	1,034.8		
1981	1,034.8	11.7	1,046.5		
1982	1,046.5	35.1	1,081.6		
1983	1,081.6	52.0	1,133.6	1/20	56.5
1984	1,077.1	2.6	1,079.7	1/19	56.8
1985	1,022.9	5.7	1,028.6	1/18	57.1
1986	971.5	-	971.5	1/17	57.1
1987	914.4	19.0	933.4	1/16	58.3
1988	875.1	1.8	876.9	1/15	58.5
1989	818.4	25.1	843.5	1/14	60.3
1990	783.2	1.3	784.5	1/13	60.3
1991	724.2	5.0	729.2	1/12	60.8
1992	668.4	6.1	674.5	1/11	61.3
1993	613.2	11.7	624.9	1/10	62.5
1994	562.4	-	562.4	1/9	62.5
1995	499.9	10.9	510.8	1/8	63.9
1996	446.9	1.3	448.2	1/7	64.0
1997	384.2	20.8	405.0	1/6	67.5
1998	337.5	5.5	343.0	1/5	68.6
1999	274.4	4.3	278.7	1/4	69.7
2000	209.0	10.4	219.4	1/3	73.1
2001	146.3	13.4	159.7	1/2	79.9
2002	79.8	-	79.8	1	79.8

ROYALTY CALCULATIONS PER SEPTEMBER 14th, 1973 LETTER OF INTENT

ALLOWANCES FOR RETURN ON CAPITAL EMPLOYED

Total Syncrude costs as at December 31st, 1977 (from February 23,1972)	$ 957.2 million
Less working capital of $ 33.7 million.	923.5 million
Less pre-production revenue (1977 crude sales of $21.8 million)	901.7 million
Total Capital employed (less working capital) as at December 31,1977.	901.7 million

	Capital Employed Less Working Capital: Start of Year	Additions	End of Year	Average	Capital Including Average	Employed W/C 75%	8% on 75%	Amortization Fraction	$MM
1978	901.7	30.9	932.6	917.2	950.9	713.2	57.1	1/25	37.3
79	895.3	5.8	901.1	898.2	931.9	698.9	55.9	1/24	37.5
80	863.6	6.4	870.0	866.8	900.5	675.4	54.0	1/23	37.8
81	832.2	11.7	843.9	838.1	871.8	653.9	52.3	1/22	38.4
82	805.5	35.1	840.6	823.1	856.8	642.6	51.4	1/21	40.0
83	800.6	52.0	852.6	826.6	860.3	645.2	51.6	1/20	42.6
84	810.0	2.6	812.6	811.3	845.0	633.8	50.7	1/19	42.8
85	769.8	5.7	775.5	772.7	806.4	604.8	48.4	1/18	43.1
86	732.4	-	732.4	732.4	766.1	574.6	46.0	1/17	43.1
87	689.3	19.0	708.3	698.8	732.5	549.4	44.0	1/16	44.3
88	664.0	1.8	665.8	664.9	698.6	524.0	41.9	1/15	44.4
89	621.4	25.1	646.5	634.0	667.7	500.8	40.1	1/14	46.2
90	600.3	1.3	601.6	601.0	634.7	476.0	38.1	1/13	46.3
91	555.3	5.0	560.3	557.8	591.5	443.6	35.5	1/12	46.7
92	513.6	6.1	519.7	516.7	550.4	412.8	33.0	1/11	47.2
93	472.5	11.7	484.2	478.4	512.1	384.0	30.7	1/10	48.4
94	435.8	-	435.8	435.8	469.5	352.1	28.2	1/9	48.4
95	387.4	10.9	398.3	392.9	426.6	320.0	25.6	1/8	49.8
96	348.5	1.3	349.8	349.2	382.9	287.2	23.0	1/7	50.0
97	299.8	20.8	320.6	310.2	343.9	257.9	20.6	1/6	53.4
98	267.2	5.5	272.7	270.0	303.7	227.8	18.2	1/5	54.5
99	218.2	4.3	222.5	220.4	254.1	190.6	15.2	1/4	55.6
2000	166.9	10.4	177.3	172.1	205.8	154.4	12.3	1/3	59.1
01	118.2	13.4	131.6	124.9	158.6	119.0	9.5	1/2	65.8
02	65.8	-	65.8	65.8	99.5	74.6	6.0	1	65.8

FORM OF APPROVAL

THE PROVINCE OF ALBERTA

THE OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Great Canadian Oil Sands Limited for the recovery of oil or a crude hydrocarbon product from oil sands.

APPROVAL NO. 1944

WHEREAS the Oil and Gas Conservation Board, now named the Energy Resources Conservation Board, by Approval No. 540, dated October 2, 1962, and as amended from time to time and the Division of Environmental Health of the Department of Health, now named the Department of the Environment (Alberta), by Final Air Pollution Approval No. 365-P-508, dated May 25, 1967, approved a scheme of Great Canadian Oil Sands Limited for the recovery of oil or a crude hydrocarbon product from oil sands, and

WHEREAS Great Canadian Oil Sands Limited has applied for amendment of the said approval and it is proper and desirable that a new approval be issued superseding the two above mentioned approvals, and

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Great Canadian Oil Sands Limited for amendment of Approval No. 540, subject to the conditions herein contained and the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970, and with the approval of the Lieutenant Governor in Council numbered O.C. __________ and dated __________, 197_, hereby orders as follows:

1. (1) The scheme of Great Canadian Oil Sands Limited (hereinafter called "Great Canadian") for the recovery of synthetic crude oil from oil sands taken from the area shown outlined on the attachment hereto, marked Appendix A to this approval, as such scheme is described in

(a) an application dated March 14, 1960, together with descriptive material accompanying or supporting the application, marked as exhibits at the said hearing,

(b) an application to permit amendment of the scheme, dated September 25, 1963, and descriptive material accompanying or supporting such application, marked as exhibits at the hearing of such application,

(c) an application to permit amendment of the scheme, dated May 12, 1967, and descriptive material accompanying or supporting such application, marked as exhibits at the hearing of such application,

(d) submissions to the Department of Health dated May 17, 1965, May 26, 1965, and September 9, 1966, and

(e) an application dated September 1, 1972, and supporting material marked as exhibits and evidence adduced at the hearing of the application,

is approved, subject to the terms and conditions herein contained.

(2) Subclause (1) does not preclude alterations in design or equipment compatible with the outlines of the scheme and made for the better operation of the scheme.

2. This approval applies to the recovery of 23,725,000 barrels per year of synthetic crude oil.

3. Great Canadian shall measure or otherwise determine the quantity of oil sands mined, oil sands processed, crude bitumen recovered and synthetic crude oil produced and any other products including coke and sulphur by a method and in a manner satisfactory to the Board.

4. Great Canadian shall furnish to the Board, in such detail and at such times as may be set by the Board

(a) monthly reports of the quantity and assay of oil sands mined, crude bitumen recovered and the quantity and disposition of all products produced or recovered therefrom, and

(b) monthly sulphur balance reports for the sulphur recovery plant and the power plant.

5. There shall be no flaring or waste of liquid or gaseous hydrocarbons produced, except in cases of emergency, unless authorized in writing by the Board.

6. (1) Great Canadian shall carry out its operations to the satisfaction of the Board and in a manner that

(a) does not preclude or render more difficult the recovery of other oil sands recoverable by practical and reasonable operations,

(b) results in the mining of the practical maximum of all crude bitumen bearing material within the area being mined,

(c) results in the processing for the recovery of synthetic crude oil of the practical maximum of all crude bitumen bearing material that is mined,

(d) results in the recovery of the practical maximum of synthetic crude oil from the bitumen bearing sand processed,

(e) results in the production of the practical minimum amount of coke in excess of the fuel requirements of the operations, and

(f) results in the recovery in the form of elemental sulphur of;

(i) from April 1, 1973 to December 31, 1973, not less than 92 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant each three month period beginning April 1, July 1 or October 1.

(ii) from January 1, 1974 to December 31, 1974, not less than 93 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant each three month period beginning January 1, April 1, July 1 or Ocotber 1.

(iii) from January 1, 1975, not less than 94 per cent of the sulphur contained in the gas delivered to the sulphur recovery plant each three month period beginning January 1, April 1, July 1 or October 1.

(2) Great Canadian shall submit for the approval of the Board, details of its annual mining plans in the third quarter of the preceding calendar year unless the Board otherwise authorizes.

7. Great Canadian shall carry out the solids disposal operations to the satisfaction of the Board and the Department of the Environment on lands to be approved by the Board and the Department of the Environment and in a manner that insures the stability of any tailings piles.

8. Great Canadian shall dispose of any liquid wastes in a manner satisfactory to the Department of the Environment and the Board in a manner that ensures that no oily or contaminative materials flow over the land or into any body of water.

9. (1) The emission of sulphur dioxide, and the sulphur dioxide equivalent of other sulphur compounds, to the atmosphere from the plant incinerator stack shall not exceed 48 long tons per day or 1.00 long tons in any half-hour period.

(2) The incinerator stack shall be of a height sufficient, having regard for the sulphur dioxide emission rate from the power plant stack, to maintain the half-hour average ground level concentrations of sulphur dioxide within the standards of the Department of the Environment and shall be not less than 350 feet.

(3) The incinerator stack flue gas emission temperature shall be a minimum of 1000° Fahrenheit.

10. (1) The emission of sulphur dioxide, and the sulphur dioxide equivalent of other sulphur compounds, to the atmosphere from the power plant stack shall not exceed 300 long tons per day or 6.3 long tons in any half-hour period.

(2) The power plant stack shall be of a height sufficient, having regard for the sulphur dioxide emission rate from the incinerator stack, to maintain the maximum half-hour average ground level concentrations of sulphur dioxide within the standards of the Department of the Environment and shall be not less than 350 feet.

(3) The power plant stack flue gas emission temperature shall be a minimum of 550° Fahrenheit.

(4) The concentration of particulates in the effluent gas from the power plant stack shall not exceed the allowable limits as specified in the regulations for the control of air pollution of the Department of the Environment.

11. (1) In the event of an emergency necessitating the flaring of sour gas or sour gaseous or liquid materials, Great Canadian shall add fuel gas to the sour gas or other materials prior to flaring, in the volumes specified by the schedule in Table I to this approval.

(2) The sour gas flare stack shall be a minimum of 250 feet in height and shall be equipped with a continuously burning pilot and an automatic flame ignitor.

(3) The hydrocarbon flare stack shall be a minimum of 325 feet in height and shall be equipped with a continuously burning pilot and an automatic flame ignitor.

12. Great Canadian shall control the emission of sulphur dust from the plant to the satisfaction of the Department of the Environment and the Board.

13. (1) Great Canadian shall conduct 5 stack surveys per year on the incinerator stack and 6 stack surveys per year on the power plant stack inlet ducts for the determination of the volume rate of flow, concentration of particulates (power plant stack only), composition and temperature of the effluent gases.

(2) At least one of the stack sampling tests required by subclause (1) shall be made when the plant is operating at not less than 90 per cent of its maximum daily production rate and at least three other of the stack sampling surveys shall be made when the plant is operating at not less than 75 per cent of its maximum daily production rate.

(3) Great Canadian shall summarize the results of all power plant and incinerator stack surveys and forward them to the Board and the Department of the Environment as soon as they are available.

14. (1) Great Canadian shall maintain a network of exposure cylinder stations for the detection of hydrogen sulphide and total sulphation in the plant vicinity to the satisfaction of the Department of the Environment.

(2) Great Canadian shall maintain a monitoring program to provide a continuous record of ground level sulphur dioxide concentration to the satisfaction of the Department of the Environment.

15. Great Canadian, in operations pursuant to the scheme, shall comply with the provisions of any applicable Act or regulation of the Province of Alberta now enacted or made, or that at any time hereafter may be enacted or made.

16. Where it appears to the Board that there has been a failure to comply with any term or condition of this approval, the Board may, in addition to any other remedy or proceeding to which it may resort, require the suspension of any operation carried on pursuant to the scheme.

17. The Operator shall comply with the attached Clean Air Act Licence No. 73 AL 114 dated October 18, 1973, and The Clean Water Act Licence No. 73 WL 041 dated May 31, 1973, issued by the Department of the Environment.

18. Board Approval No. 540 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this _____ day of ______, A. D. 1973.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

TABLE I TO APPROVAL NO. 1944

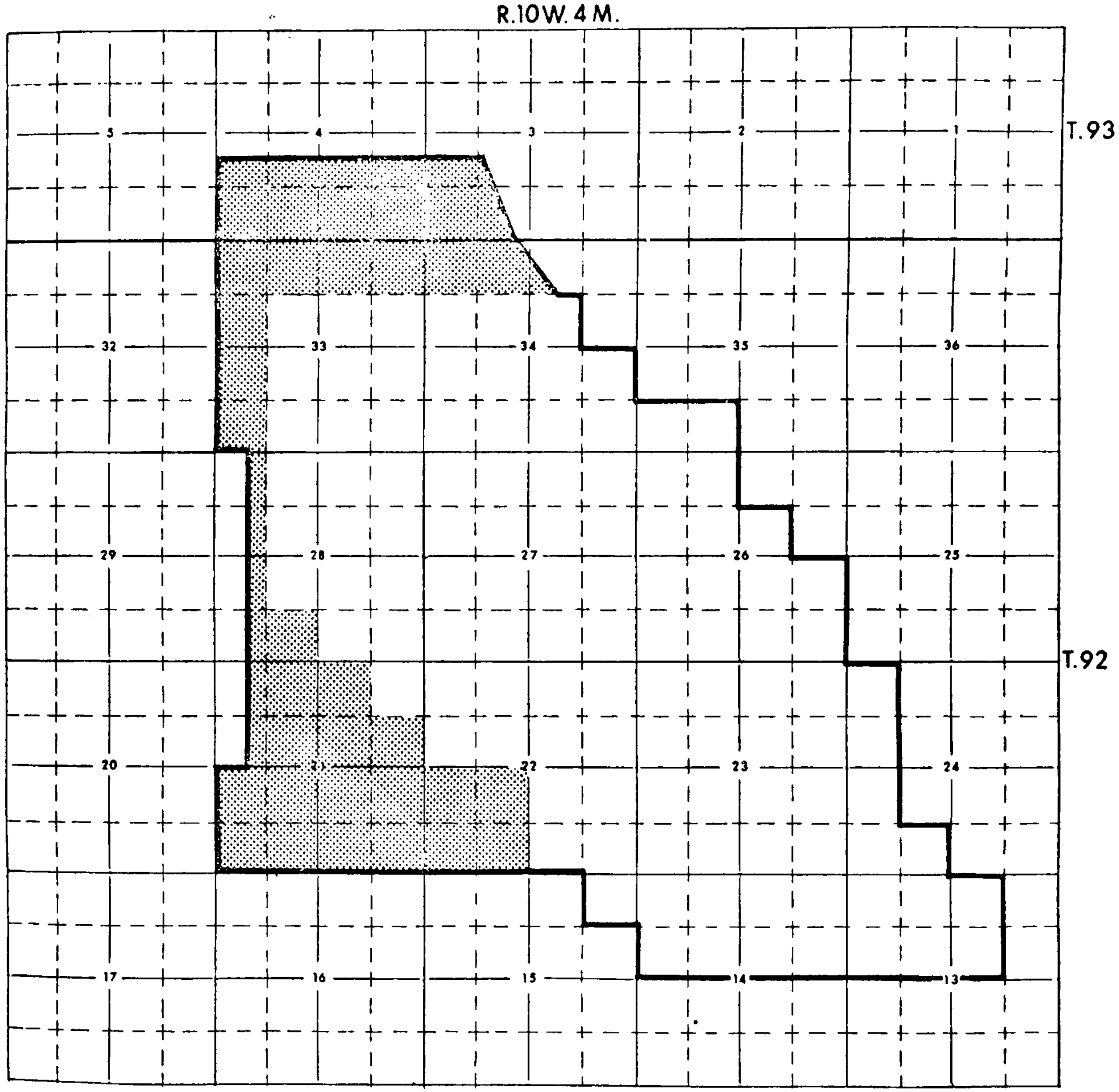
FUEL RATES FOR FLARING SOUR GAS

1. For short periods of emergency flaring (periods not greater than 1 hour) the maximum downwind ground level concentration of sulphur dioxide must not exceed 1.0 parts per million. For a 250 foot high flare stack the following fuel gas schedule should be followed to maintain 1.0 parts per million downwind concentration assuming the heating value of residue gas as 1000 Btu's per cubic foot.

Cubic Feet Per Second Hydrogen Sulphide	Long Tons Sulphur Per Day	Cubic Feet Per Second Fuel Gas	Million Cubic Feet Per Day Fuel Gas
23.1	71.4	Nominal	Nominal
46.3	142.9	Nominal	Nominal
69.4	214.3	Nominal	Nominal
92.6	285.8	Nominal	Nominal
115.7	357.2	Nominal	Nominal
138.9	428.6	Nominal	Nominal

2. For periods of emergency flaring greater than 1 hour the maximum downwind ground level concentration of sulphur dioxide must not exceed 0.3 parts per million. For a 250 foot high flare stack the following fuel gas schedule should be followed to maintain 0.3 parts per million downwind concentration assuming the heating value of residue gas to 1000 Btu's per cubic foot.

Cubic Feet Per Second Hydrogen Sulphide	Long Tons Sulphur Per Day	Cubic Feet Per Second Fuel Gas	Million Cubic Feet Per Day Fuel Gas
23.1	71.4	16.3	1.41
46.3	142.9	50.0	4.32
69.4	214.3	115.7	10.00
92.6	285.8	173.6	15.00
115.7	357.2	229.2	19.80
138.9	428.6	281.3	24.30



APPENDIX A TO APPROVAL NO. 1944

AREA OF CHANGE FROM PREVIOUS ORDER-

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

federal register

FRIDAY, NOVEMBER 30, 1973
WASHINGTON, D.C.

Volume 38 ■ Number 230

PART III

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

■

MODIFICATION OF OIL SHALE WITHDRAWAL IN COLORADO, UTAH, WYOMING

Sale of Oil Shale Leases

Title 43—Public Lands: Interior

CHAPTER II—BUREAU OF LAND MANAGEMENT, DEPARTMENT OF THE INTERIOR

APPENDIX—PUBLIC LAND ORDERS

[Public Land Order 5401]

COLORADO, UTAH, WYOMING

Modification of Oil Shale Withdrawal

By virtue of the authority vested in the President, and pursuant to Executive Order No. 10355 of May 26, 1952 (17 FR 4831), it is ordered as follows:

1. Executive Order No. 5327 of April 15, 1930, withdrawing oil shale deposits and land containing such deposits for classification, is hereby modified to permit, at the discretion of the Secretary, the issuance of leases of oil shale deposits, and the land containing such deposits, so far as it relates to the following described land:

COLORADO

SIXTH PRINCIPAL MERIDIAN

Tract C–a

T. 1 S., R. 99 W.,
Sec. 32, E½, E½W½;
Sec. 33;
Sec. 34, W½, SE¼, W½NE¼, SE¼NE¼.
T. 2 S., R. 99 W.,
Secs. 3 and 4;
Sec. 5, E½, E½W½;
Sec. 8, E½;
Secs. 9 and 10.

Tract C–b

T. 3 S., R. 96 W.,
Sec. 5, W½SE¼, SW¼;
Sec. 6, lots 6 and 7, E½SW¼, SE¼;
Sec. 7, lots 1, 2, 3, 4, E½W½, E½;
Sec. 8, W½NE¼, NW¼, S½;
Sec. 9, SW¼;
Sec. 16, NW¼, W½SW¼;
Sec. 17;
Sec. 18, lots 1, 2, 3, 4, E½W½, E½.
T. 3 S., R. 97 W.,
Sec. 1, S½;
Sec. 2, SE¼;
Sec. 11, E½;
Sec. 12;
Sec. 13, N½;
Sec. 14, N½NE¼.

The two tracts described above contain 10,183.60 acres.

UTAH

SALT LAKE MERIDIAN

Tract U–a

T. 10 S., R. 24 E.,
Sec. 19 E½;
Secs. 20, 21, 22, 27, 28, 29;
Sec. 30, E½;
Sec. 33, N½;
Sec. 34, N½.

Tract U–b

T. 10 S., R. 24 E.,
Sec. 12, S½, S½N½;
Secs. 13, 14, 23, 24;
Sec. 25, W½W½;
Sec. 26.
T. 10 S., R. 25 E.,
Secs. 18 and 19.

The two tracts described above contain 10,240 acres.

WYOMING

SIXTH PRINCIPAL MERIDIAN

Tract W–a

T. 14 N., R. 99 W.,
Secs. 17 and 18;
Sec. 19, NE¼;
Secs. 20, 21, 22, 27, 28;
Sec. 29, N½, SE¼.

Tract W–b

T. 13 N., R. 99 W.,
Sec. 1, S½, S½N½, lots 1, 3, 4;
Secs. 2 and 3;
Sec. 4, lot 1, SE¼NE¼;
Sec. 10, E½, E½NW¼;
Secs. 11 and 12.
T. 14 N., R. 99 W.,
Sec. 33, E½E½;
Secs. 34 and 35.

The two tracts described above contain 10,194.48 acres. The total areas described aggregate approximately 30,618.08 acres.

2. The lands described in paragraph 1 of this order will not be available for lease until a notice of sale of leases is published in the FEDERAL REGISTER announcing the terms and conditions under which leases on these tracts will be offered. Any application to lease not submitted in accordance with the requirements prescribed in that notice of sale will be rejected.

JOHN C. WHITAKER,
Under Secretary of the Interior.

NOVEMBER 26, 1973.

[FR Doc.73-25371 Filed 11-29-73;8:45 am]

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

OIL SHALE LEASES

Notice of Sale

Pursuant to the Act of February 25, 1920 (41 Stat. 437), as amended (30 U.S.C. 181-263), the oil shale deposits in six tracts of land (two in Colorado, two in Utah, and two in Wyoming) will be offered for lease through competitive bidding. The six sales will be held sequentially, one every second Tuesday of the month, beginning January 8, 1974, as follows: TRACT C-a in Colorado will be offered for lease on January 8, 1974; TRACT C-b in Colorado will be offered on February 12, 1974; TRACT U-a in Utah will be offered on March 12, 1974; Utah TRACT U-b on April 9, 1974; Wyoming TRACT W-a on May 13, 1974; and Wyoming TRACT W-b on June 11, 1974. These tracts are more particularly described as follows:

COLORADO

TRACT C-a:

T. 1 S., R. 99 W., 6th P.M.,
Sec. 32, E½, E½W½;
Sec. 33, all;
Sec. 34, W½, SE¼, W½NE¼, SE¼NE¼.
T. 2 S., R. 99 W., 6th P.M.,
Sec. 3, all;
Sec. 4, all;
Sec. 5, E½, E½W½ (incl. lots 1, 2, and 3);
Sec. 8, E½;
Sec. 9, all;
Sec. 10, all.

The area described aggregates 5,089.70 acres.

TRACT C-b:

T. 3 S., R. 96 W., 6th P.M.,
Sec. 5, W½SE¼, SW¼;
Sec. 6, lots 6 and 7, E½SW¼, SE¼;
Sec. 7, lots 1, 2, 3, and 4, E½W½, E½;
Sec. 8, W½NE¼, NW¼, S½;
Sec. 9, SW¼;
Sec. 16, NW¼, W½SW¼;
Sec. 17, all;
Sec. 18, lots 1, 2, 3, and 4, E½W½, E½.
T. 3 S., R. 97 W., 6th P.M.,
Sec. 1, S½;
Sec. 2, SE¼;
Sec. 11, E½;
Sec. 12, all;
Sec. 13, N½;
Sec. 14, N½NE¼.

The area described aggregates 5,093.90 acres.

UTAH

TRACT U-a:

T. 10 S., R. 24 E., S.L.M.,
Sec. 19, E½;
Sec. 20, all;
Sec. 21, all;
Sec. 22, all;
Sec. 27, all;
Sec. 28, all;
Sec. 29, all;
Sec. 30, E½;
Sec. 33, N½;
Sec. 34, N½.

The area described aggregates 5,120.00 acres.

TRACT U-b:

T. 10 S., R. 24 E., S.L.M.,
Sec. 12, S½, S½N½;
Sec. 13, all;
Sec. 14, all;
Sec. 23, all;
Sec. 24, all;
Sec. 25, W½W½;
Sec. 26, all.
T. 10 S., R. 25 E., S.L.M.,
Sec. 18, all;
Sec. 19, all.

The area described aggregates 5,120.00 acres.

WYOMING

TRACT W-a:

T. 14 N., R. 99 W., 6th P.M.,
Sec. 17, all;
Sec. 18, all;
Sec. 19, NE¼;
Sec. 20, all;
Sec. 21, all;
Sec. 22, all;
Sec. 27, all;
Sec. 28, all;
Sec. 29, N½, SE¼.

The area described aggregates 5,111.24 acres.

TRACT W-b:

T. 13 N., R. 99 W., 6th P.M.,
Sec. 1, S½, S½N½, lots 1, 3, and 4;
Sec. 2, all;
Sec. 3, all;
Sec. 4, Lot 1, SE¼NE¼;
Sec. 10, E½, E½NW¼;
Sec. 11, all;
Sec. 12, all.
T. 14 N., R. 99 W., 6th P.M.,
Sec. 33, E½E½;
Sec. 34, all;
Sec. 35, all.

The area described aggregates 5,083.24 acres.

Announcement of each sale will be made by publication of a special notice in the FEDERAL REGISTER and in a newspaper of general circulation in the State and county in which the offered lands are located, setting forth the date, time, place, and conditions of the sale. If there is no newspaper in the county in which the lands are situated, then publication of the notice of sale will be made in a newspaper in the general area of the offered lands.

1. *Acreage limitations:* Not more than one lease shall be granted to any one person, association, or corporation.

2. *Lease terms:* The leases will be issued on a form the full text of which is published as Appendix "A" to this notice. The lease will be issued for a period of 20 years and so long thereafter as production is had in commercial quantities, subject to readjustment of terms at the end of each 20-year period. The lessee will be required to pay royalty on production in the amount and manner prescribed in Section 7 of the lease, and to maintain a bond as provided in Section 9.

3. *Minimum Royalty:* Section (7)(e) (1) of the lease form requires the payment of a minimum royalty for the sixth and each succeeding year which shall be based upon a different production rate for each tract and upon different grades of oil shale for certain tracts. The production rates and oil shale grades for each tract are as follows:

Tract	Shale grade gallon/ton	6th year production rate 1,000's ton/year	15th year production rate 1,000's ton/year
Tract C-a	30	1,130	11,300
Tract C-b	30	616	6,160
Tract U-a	30	208	2,080
Tract U-b	30	227	2,270
Tract W-a	20	215	2,150
Tract W-b	20	214	2,140

4. *Bidding procedures:* Leases will be offered competitively through sealed bidding. A lease will be issued only to the qualified bidder submitting the highest amount per acre as a bonus for the privilege of leasing the lands. No specific form of bid is required but all bids must identify the lease sale and must show the total amount bid, the amount bid per acre, and the amount submitted with the bid. No telephonic or telegraphic bids will be accepted, and no oil payment, overriding royalty, logarithmic, or sliding scale bid will be considered. Bids shall not be modified after they have been submitted. Bids must be for the full tract described in the special notice of sale of oil shale lease. Bids must be submitted in sealed envelopes plainly marked "Sealed Bid for Oil Shale Lease. Not to be opened before 10 a.m., M.S.T. on (*date of sale*)." Bids may be mailed or delivered in person to the addressee named in the special notice until 10 a.m., M.S.T. on the date of the sale. Bids received after that time will be returned unopened. Bidders are warned against violation of section 1860 in Title 18 U.S.C. prohibiting unlawful combination or intimidation of bidders.

5. *Payment of bonus and advance rental:* All bids must be accompanied by a certified check, cashier's check, bank draft, money order, or cash for one-fifth of the bonus bid payable to the Bureau of Land Management, which amount shall be returned to the bidder after the lease sale should he be an unsuccessful bidder. If the bidder, after being notified that his bid has been accepted and that he will be awarded a lease, fails to comply with the applicable regulations or the terms of this notice, or if he fails to execute the lease within 15 days after receiving the lease form, his deposit will be forfeited.

Each bid must also be accompanied by a certified check, cashier's check, bank draft, moneyo rder, or cash for the first year's annual rental at the rate of 50¢ per acre or fraction thereof, which amount shall be returned to all unsuccessful bidders after the lease sale.

6. *Evidence of qualifications:* Each bid must be accompanied by a statement over the bidder's signature or that of his authorized agent with respect to his

qualifications. The statement shall contain the following information:

(a) If the bidder is an individual, a statement as to whether native born or naturalized; if an association, it must submit a certified copy of the articles of association and a statement by its members as to their citizenship. If the bidder is a corporation, it must submit statements showing: (i) the State in which it is incorporated; (i) that it is authorized to hold leases for oil shale deposits, and the names of the officers authorized to act in such matters in behalf of the corporation; (iii) the percentage of the corporate voting stock and of all the stock owned by aliens or those having addresses outside the United States; and (iv) the name, address, and citizenship of any stockholder owning or controlling 20 percent or more of the corporate stock of any class. If more than 10 percent of the stock is owned or controlled by or in behalf of aliens, or persons who have addresses outside the United States, the corporation must give their names and addresses, the amount and class of stock held by each, and to the extent known to the corporation or which reasonably can be ascertained by it, the facts as to the citizenship of each. The bid of a corporation also shall be accompanied by a copy either of the minutes of the meeting of the board of directors or of the by-laws indicating that the person signing the bid has authority to do so, or, in lieu of such a copy, a certificate by the Secretary of the corporatiton to that effect, over the corporate seal, or appropriate reference to the record of the Bureau of Land Management in connection with which such aticles and authority have been furnished previously; and

(b) The certification required by 41 CFR 60-1.7(b) and Executive Order No. 11246 of September 24, 1965, as amended by Executive Order No. 11375, on Form 1140-8 (November 1973) and Form 1140-7 (December 1971).

7. *Bid opening:* The bids will be opened at the place, date and time announced in the notice of publication of the respective oil shale lease sales. The opening of bids is for the purpose of publicly announcing and recording bids received and no bids will be accepted or rejected at that time. If the Department is prohibited for any reason from opening any bid before midnight of the day of the sale for which it is submitted, that bid will be returned unopened to the bidder as soon thereafter as possible.

8. *Acceptance or rejection of bids:* No bid for any tract will be accepted and no lease for any tract will be awarded to any bidder unless the bidder has complied with all requirements of the notice, his bid is the highest for the offered tract, and the amount of the bonus bid has been determined to be adequate by the United States. The Government reserves the right to reject any or all bids. Any cash, checks, drafts, or money orders submitted with the bid may be deposited in an unearned escrow account in the Treasury during the period the bids are being considered. Such a deposit does not constitute and shall not be construed as acceptance of any bids on behalf of the United States.

9. *Preliminary Development Plan:* Within forty-eight hours after being informed that his bid has been accepted and that a lease will be issued to him, the successful bidder must transmit a preliminary development plan, in duplicate, to the Officer conducting the lease sale. This plan will be made public upon issuance of the lease, and, therefore, confidential information relative to the lessee's operations should not be included in the submission. Confidential information should be submitted in the same manner, but under separate cover. The submission or acceptance of these plans will not be binding on the lessee or lessor and will not authorize any action by the lessee, but the plan is required for the lessor's guidance in establishing initial supervision of the lessee's activities. The preliminary development plan should include the method of development, the proposed location of on and off-site facilities, the schedule for development, and monitoring programs to determine environmental criteria.

10. *Withdrawal of additional lands:* The Department recognizes that in some situations lands outside the leased tracts may be required under other statutes than the Mineral Leasing Act for roads or other purposes in connection with the prototype oil shale leasing program. Moreover, since this is a prototype rather than a general leasing program, the Department may in the future find it desirable to conduct investigations, studies, and experiments under section 101 of the Public Land Administration Act (43 U.S.C. § 1362), particularly in connection with the disposal of spend shale. In order to facilitate these possible future investigations, studies, and experiments, the Department is withdrawing from all forms of appropriation under the public land laws, including the mining laws, certain lands in the vicinity of the tracts offered for lease.

11. Further information concerning these oil shale lease sales may be obtained from the Oil Shale Coordinator, Room 5623, Interior Building, Washington, D.C. 20240; the Deputy Oil Shale Coordinator, Building 56, Denver Federal Center, Denver, Colorado, the Chief, Division of Upland Minerals, Bureau of Land Management, Room 7146, Interior Building, 18th & C Streets NW., Washington, D.C. 20240; the State Director, Colorado State Office, Bureau of Land Management, Room 700, Colorado State Bank Building, 1600 Broadway, Denver, Colorado 80202; the State Director, Utah State Office, Bureau of Land Management, Federal Building, 125 South State, Salt Lake City, Utah 84138; and the State Director, Wyoming State Office, Bureau of Land Management, Joseph C. O'Mahoney Federal Center, 2120 Capital Avenue, Cheyenne, Wyoming 82001.

CURT BERKLUND,
Director,
Bureau of Land Management.

Approved: November 26, 1973.

JOHN C. WHITAKER,
Under Secretary of the Interior.

APPENDIX A

OIL SHALE LEASE

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UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF LAND MANAGEMENT

Oil Shale Lease

In consideration of the mutual promises, terms and conditions contained herein, and the grant made hereby, this lease is entered into on ____________, ______, to be effective on ____________, ______, (hereinafter called the "Effective Date"), by the United States of America (hereinafter called the "Lessor"), acting through the Bureau of Land Management (hereinafter called the "Bureau") of the Department of the Interior (hereinafter called the "Department"), and ____________ ____ (hereinafter called the "Lessee"), pursuant and subject to the terms and provisions of the Mineral Leasing Act of February 25, 1920 (41 Stat. 437), as amended (30 U.S.C. §§ 181–263) (hereinafter called the "Act"), and to the terms, conditions, and requirements (1) of all regulations promulgated by the Secretary of the Interior (hereinafter called the "Secretary") in existence upon the Effective Date, specifically including, but not limited to, the regulations in 30 CFR Part 231 and 43 CFR Part 23 and Group 3000, all of which are incorporated herein and, by reference, made a part hereof; and (2) of all regulations hereafter promulgated by the Secretary (except those inconsistent with any specific provisions of this lease other than regulations incorporated herein by reference), all of which shall be, upon their effective date, incorporated in and, by reference, made a part of this lease.

Section 1. *Definitions*. As used in this lease:

(a) "Oil Shale" means a fine-grained sedimentary rock containing: (1) organic matter which was derived chiefly from aquatic organisms or waxy spores or pollen grains, which is only slightly soluble in ordinary petroleum solvents, and of which a large proportion is distillable into synthetic petroleum, and (2) inorganic matter which may contain other minerals. This term is applicable to any argillaceous, carbonate, or siliceous sedimentary rock which, through destructive distillation will yield synthetic petroleum. The products of Oil Shale include both shale oil and other minerals;

(b) "Leased Lands" means ____________ ________________ situated in the County of ____________, State of __________ containing ________ acres, more or less;

(c) "Leased Deposits" means all deposits of Oil Shale lying within or under the Leased Lands;

(d) "Anniversary Date" means the anniversary of the Effective Date of this lease; however, if operations under this lease are suspended pursuant to section 39 of the Act (30 U.S.C. § 209), the next Anniversary Date of this lease after the suspension shall follow the previous Anniversary Date by a period of time equal to the sum of one year and the period of suspension, and subsequent Anniversary Dates will be measured from that Anniversary Date;

(e) "Lease Year" means the period of time between two successive Anniversary Dates of this lease;

(f) "Ton" means a measure of weight of 2,000 pounds avoirdupois;

(g) "Mining Supervisor" means the appropriate mining supervisor of the United States Geological Survey (hereinafter called the "Geological Survey"), as defined in 30 CFR 231.2(c); and

(h) "Commercial Quantities" means quantities sufficient to provide a return after all variable costs of production have been met.

Sec. 2. *Grant to lessee*. The Lessee is hereby granted, subject to the terms of this lease, the exclusive right and privilege to prospect for, mine by underground or surface means and process by retorting or by *in situ* methods or otherwise, as he may reasonably choose and in accordance with approved plans, utilize, and dispose of all Leased Deposits together with the right to construct on the Leased Lands all such works, buildings, plants, structures, roads, powerlines, and additional facilities as may be necessary or reasonable convenient for the mining, processing, and preparation of products of the Leased Deposits for market and the housing and welfare of the Lessee's employees, agents, and contractors, and to use so much of the surface of the Leased Lands as may reasonably be required in the exercise of the rights and privileges herein granted.

Sec. 3. *Lessor's reserved interests in the Leased Lands*. The Lessor reserves the following:

(a) The right to lease, sell, or otherwise dispose of the surface of the Leased Lands or of any surface or mineral resource in the Leased Lands (or of any interest therein) under existing laws or laws hereafter enacted, subject to the rights of the Lessee under this lease;

(b) The right, upon such terms as it may determine to be just, to permit for joint or several use, such easements or rights-of-way, including easements in tunnels upon, through, or in the Leased Lands, as may be necessary or appropriate to the working of the Leased Lands or other lands containing mineral deposits subject to the Act, and the treatment and shipment of the products thereof by or under authority of the Lessor, its Lessees, or permittees, and for other public purposes; and

(c) The right to conduct and to authorize geological and other investigations on the Leased Lands which do not interfere with or endanger operations under this lease.

Sec. 4. *Lease Term*. This lease shall be for a period of 20 Lease Years from the Effective Date and so long thereafter as there is production from the Leased Deposits in commercial quantities, subject to the provisions of section 23 with respect to the readjustment of terms and conditions and the right of the parties to terminate the lease.

Sec. 5. *Bonus*. In addition to all other payments required hereunder, the Lessee shall pay to the Lessor the amount of $______ as a bonus. This bonus shall be due and payable in five installments as follows: Receipt of $______ at the time of the sale as the first installment is hereby acknowledged by the Lessor; the balance shall be paid in four equal annual installments of $______ due and payable on each of the first four Anniversary Dates of this lease. In the event the Secretary accepts a surrender or relinquishment of this lease filed by the Lessee at any time prior to the third Anniversary Date, the Lessee shall be released from any obligation to pay the fourth and fifth bonus installments required hereunder. That release shall not relieve the Lessee of the obligation to pay installments which had accrued prior to the filing of the surrender or relinquishment of the lease, but had not been paid prior to the Secretary's acceptance of that surrender or relinquishment. The Lessee may credit against the fourth bonus installment any expenditures prior to the third Anniversary Date directly attributable to operations under this lease on the Leased Lands for the development of the Leased Deposits, but not any expenditures attributable to the preparation of a development plan under section 10 of this lease. Upon the credit of an expenditure, the Lessee shall be relieved of the duty of paying the equivalent amount of the fourth bonus installment. Similarly, the Lessee may credit against the fifth bonus installment any expenditures prior to the fourth Anniversary Date directly attributable to operations under this lease on the Leased Lands for the development of the Leased Deposits and not credited against the fourth bonus installment, but not any expenditures attributable to the preparation of a development plan under section 10. Upon the credit of an expenditure, the Lessee shall be relieved of the duty of paying the equivalent amount of the fifth bonus installment. The Mining Supervisor shall have the duty of determining whether expenditures credited by the Lessee are properly attributable to such operations, and, if the Mining Supervisor determines that any reported expenditure is not attributable to such operations, the Lessee shall not receive credit for that expenditure.

Sec. 6. *Rentals*. The Lessee shall pay the Lessor an annual rental which shall be in the amount of 50 cents for each acre or fraction of an acre of the Leased Lands. The Lessee shall pay the rental for each subsequent Lease Year on or before the first day of that Lease Year. Rentals for any Lease Year shall be credited by the Lessor against any royalty payments for that Lease Year.

Sec. 7. *Royalties*. (a) The Lessee shall pay to the Lessor a royalty on all Oil Shale extracted by the Lessee from the Leased Lands which is either processed or sold by the Lessee. The royalty on Oil Shale shall be computed separately for shale oil and for other minerals as follows:

(1) The royalty on shale oil shall be computed on the basis of the shale oil content of the Oil Shale; the method of computing the royalty shall depend upon whether the Oil Shale is extracted by mining methods or processed by *in situ* methods.

(i) If the Oil Shale is extracted by mining methods, the Lessee shall pay the Lessor a basic royalty rate of 12 cents on every Ton of Oil Shale which the Lessee either processes under this Lease either on or off the Leased Lands or sells prior to processing. This basic royalty rate shall be subject to the following adjustments:

(A) If the shale oil content of the Oil Shale mined is less than 30 gallons per Ton, the basic royalty rate per Ton of Oil Shale shall be reduced by one cent for each gallon or fraction thereof that the shale oil content is less than 30 gallons per Ton, but in no event shall the royalty rate be less than four cents per Ton. If the shale oil content of the Oil Shale mined is more than 30 gallons per Ton, the basic royalty rate per Ton shall be increased by one cent for each gallon or fraction thereof that the shale oil content is more than 30 gallons per Ton.

(B) For the calendar year in which the Effective Date occurs and for each calendar year thereafter, the Secretary shall determine the combined average value per barrel of all crude oil and crude shale oil produced in the States of Colorado, Utah, and Wyoming. The basic royalty rate applicable to the second and each succeeding Lease Year shall be adjusted by an increase or decrease of the same percentage as the percentage of increase or decrease in the combined average value for the calendar year during which that Lease Year begins as compared with the combined average value for the calendar year during which the previous Lease Year began. However, in no event shall the basic royalty rate for shale oil be decreased to less than 4 cents on every Ton of Oil Shale mined under the lease.

(C) The shale oil content of the Oil Shale shall be determined either by the Modified Fischer Assay method or by such other method as the Lessor and the Lessee adopt, and the royalty shall be based on the monthly average of shale oil content of all Oil Shale processed under this lease or transferred from the Leased Lands for processing or sale of the Lessee. Computations of quantities, assays and royalties shall be rounded to the nearest hundredth, or within the limits of the standard deviation for commercial testing equipment as approved by the Mining Supervisor.

(ii) (A) If the Oil Shale is processed by *in situ* methods, royalty shall be paid at a basic royalty rate of 12 cents per Ton. The number of Tons processed shall, for purposes of computing royalty, be determined by: (I) establishing through calorimetric tests designated by the American Society for Testing and Materials as "Standard" or "Tentative," the total gross heat of combustion in BTUs of all oil and gas products at the well head, adjusted downward by the total gross heat of combustion in BTUs of combustible fluids (gases or liquids) injected as heat carriers, but not for fuel purposes, into the formation being processed; (II) dividing the adjusted total gross heat of combustion in BTUs by 152,700 BTUs (shale oil and gas recovered by Modified Fischer Assay of Oil Shales, containing approximately 30 gallons of shale oil per Ton, has a heating value of 152,700 BTUs per gallon of shale oil and associated gas), to arrive at the equivalent number of gallons of shale oil produced; and (III) dividing the equivalent number of gallons of shale oil produced by 30, to arrive at the number of Tons of Oil Shale processed by *in situ* methods.

(B) The basic royalty rate applicable to shale oil from Oil Shale process by *in situ* methods shall be adjusted in the same manner as that provided in paragraph (a) (1) (i) (B) of this section for the adjustment of the basic royalty rate applicable to shall oil processed from Oil Shale extracted by mining methods.

(C) Computations of quantities, assays and royalties relating to tonnage of Oil Shale shall be determined by the same standards as used under Section 7 (a) (1) (i) (C).

(2) The Lessee shall also pay a royalty on all minerals other than shale oil contained in Oil Shale produced from the Leased Deposits which the Lessee processes, either on or off the Leased Lands, or sells. This royalty shall be computed on the basis of the gross value of the other minerals at the point of shipment to market, and shall be at a rate of 3 per centum for the first ten Lease Years, 4 per centum for the eleventh year through the fifteenth Lease Year, and 5 per centum beginning with the sixteenth Lease Year.

(b) The Lessee shall determine accurately, on the Leased Lands, the weight or quantity and quality of all Oil Shale produced from the Leased Deposits by each method used and shall enter the weight or quantity and quality thereof accurately in books which shall be kept and preserved by the Lessee for such purposes.

(c) Payments for royalties due under this lease shall be payable monthly on or before the last day of the calendar month following the calendar month in which the Oil Shale is processed or, if it is not processed, is sold.

(d) If the Lessee shall show that compliance with the requirements for environmental protection prescribed in the detailed development plan (or amended, supplemental, or partial plan) required under section 10 of this lease, and as approved in accordance with the regulations in 43 CFR Part 23 and 30 CFR Part 231, now or hereinafter in force, or imposed by legislation enacted after the effective date of that plan (or of an amendment or supplement to that plan), has engendered or will engender extraordinary costs in an amount which is in excess of those in the contemplation of the parties, as determined by the Lessor, on the effective date of that plan (or amendment or supplement to that plan), and the Secretary, if he deems it desirable, may, in order to offset such costs, adjust the royalties that would otherwise become due and payable thereafter under subsection (a) of this section by allowing a credit against those royalties in such an amount, and for such a time as he determines is warranted in the circumstances.

(e) (1) For the sixth and each succeeding Lease Year the Lessee shall pay a minimum royalty which, to the extent that royalties on production during that Lease Year in that amount have not been previously paid, shall be due and payable on the Anniversary Date at the end of that Lease Year. For the sixth Lease Year, the Lessee's minimum royalty shall be equal to the royalty due on shale oil under subsection (a) (1) (i) of this section on an annual production rate of ——— Tons of Oil Shale containing ——— gallons of shale oil per Ton of Oil Shale. The annual production rate for computing minimum royalty for each subsequent Lease Year up to and including the fifteenth Lease Year shall increase in an amount of ——— Tons of Oil Shale per year for each subsequent Lease Year; for the fifteenth and each subsequent Lease Year the annual rate shall be ——— Tons of Oil Shale. The Secretary may excuse the Lessee from compliance, in whole or in part, with the requirements of this paragraph (1) of subsection (e) during any year in which the Lessee is prevented by circumstances over which he has no control from implementing a development plan submitted under Section 10 of this lease.

(2) The Lessee may credit against any minimum royalty due on the sixth Anniversary Date or any subsequent Anniversary Date up to and including the tenth Anniversary Date the amount of any expenditures which are made between the approval of the development plan under section 10 of this lease and the tenth Anniversary Date and which are directly attributable to operations on the Leased Lands pursuant to that development plan for the development of the Leased Deposits and which were not credited against the fourth and fifth bonus installments. The Mining Supervisor shall have the duty of determining whether expenditures credited by the Lessee are attributable to such operations, and, if the Mining Supervisor determines that any reported expenditure is not attributable to such operations, the Lessee shall not receive credit for the expenditure. Upon the credit of an expenditure against the minimum royalty due, the Lessee will be relieved of the duty of paying the equivalent amount of minimum royalty: *Provided, however,* That, if there is actual production in the sixth or any subsequent Lease Year, the Lessee shall not be permitted to credit expenditures against the first $10,000 of minimum royalty due for that Lease Year.

(f) If the Lessee enters into production prior to the eighth Anniversary Date, and the royalty due in the eighth or any previous Lease Year exceeds the minimum royalty due under subsection (e) (1) of this section for that Lease Year, the Lessee shall be relieved from the payment of one-half of the difference between the actual royalty due for that Lease Year and the figure set in subsection (e) (1) for minimum royalty due for that Lease Year. This relief from the payment of royalty shall be in addition to any crediting of expenditures under subsection (e) (2) of this section, but no crediting of expenditures against minimum royalty shall reduce the figure for minimum royalty used in the preceding sentence.

Sec. 8. *Payments.* All bonus installments shall be paid to the appropriate State Office of the Bureau. All rental payments shall be made to the appropriate State Office of the Bureau until this lease enters a producing status or minimum royalty is required to be paid on it; thereafter the rentals and royalties shall be paid to the appropriate Mining Supervisor with whom all reports (including any reports on expenditures deductible under section 5) concerning operations under the lease shall be filed. All remittances to the Bureau shall be made payable to the Bureau of Land Management; those to the Geological Survey shall be made payable to the United States Geological Survey.

Sec. 9. *Bond.* (a) The Lessee shall file with the appropriate Bureau office and maintain a bond in the amount of $20,000 for the purpose of ensuring compliance with the provisions of this lease, except these provisions for compliance with which a separate bond is required under subsection (b) of this section.

(b) (1) Upon approval of a detailed development plan under section 10 of this lease, the Lessee shall file with the appropriate Bureau office and maintain, in addition to the bond required under subsection (a) of this section, a bond (in an amount determined pursuant to paragraph (2) of this subsection) which shall be conditioned upon the faithful compliance with the regulations in 30 CFR Part 231 and 43 CFR Part 23, the provisions of sections 10 and 11 of this lease, the Oil Shale Lease Environmental Stipulations attached to this lease pursuant to section 11, and any approved development plan (or approved, amended, supplemental or partial plan), to the extent that it relates to the preservation and protection and conservation of resources other than Oil Shale during the conduct of exploration or mining operations, and the reclamation of lands and waters affected by exploration or mining operations.

(2) During the first three Lease Years after the approval of a detailed development plan under section 10 of this lease, the bond shall be in an amount equal to (i) $2,000 per acre for all portions of the Leased Lands which, pursuant to the plan, will be used for spent shale disposal sites and sites for actual mining operations during that three year period and (ii) $500 per acre for all other portions of the Leased Lands upon which operations will be conducted or which will be directly affected by operations during that three year period under the plan, but the total bond shall in no event be less than $20,000. After the first three Lease Years the bond shall be renewed at intervals of three Lease Years. Each renewed bond shall be for three Lease Years and at such a total figure as shall be determined by the Lessor to be needed to provide for the reclamation and restoration of all portions of the Leased Lands which have been affected by previous operations under this lease or which will be affected by operations under this lease during the ensuing three year period. The amount of the bond shall be increased at any time during the three-year period at the demand of the Lessor if there is a change in the development plan which, in the opinion of the Lessor, increases the possibility of environmental damage. Upon request of the Lessee, the bond may be released as to all or any portion of the Leased Lands affected by exploration or mining operations during the three year period covered by the bond when the Lessor has determined that the Lessee has successfully met the reclamation requirements of the approved development plan and that operations have been carried out and completed with respect to these lands in accordance with the approved plan.

(c) Prior to the approval of any plan for exploratory work under section 10(d) of this lease, the Lessee shall file with the appropriate Bureau office and maintain, in addition to the bond required under subsection (a) of this section, a bond in such an amount as the Mining Supervisor shall require, but in no event less than $20,000, which shall be conditioned upon the faithful compliance with regulations in 30 CFR Part 231 and 43 CFR Part 23, the provisions of sections 10 and 11 of this lease, the Oil Shale Lease Environmental Stipulations attached to this lease pursuant to section 11, and any approved plan for exploratory work, to the extent that it relates to the preservation and protection of the environment (including land, water, and air), the protection and conservation of resources other than Oil Shale during the conduct of exploration operations, and the reclamation of lands and waters affected by exploration operations.

The bond required by this subsection shall apply only to actions taken prior to the date of approval of the development plan under section 10(a) of this lease. However, with the consent of the Mining Supervisor, the Lessee may modify this bond in such a manner as is necessary to meet the requirements of subsection (b) of this section, and the bond so modified may, with the consent of the Mining Supervisor, be maintained as the bond required under subsection (b).

Sec. 10. *Development plan and diligence requirements.* (a) The Lessee shall file with the Mining Supervisor on or before the third Anniversary Date a detailed development plan. This plan shall include: (1) a schedule of the planning, exploratory, development, production, processing, and reclamation operations and all other activities to be conducted under this lease; (2) a detailed description pursuant to 30 CFR Part 231 and 43 CFR Part 23 of the procedures to be followed to assure that the development plan, and lease operations thereunder, will meet and conform to the environmental criteria and controls incorporated in the lease; and (3) a requirement that the Lessee use all due diligence in the orderly development of the Leased Deposits, and, in particular, to attain, at as early a time as is consistent with compliance with all the provisions of this lease, production at a rate at least equal to the rate on which minimum royalty is computed under section 7(e)(1).

Prior to commencing any of the operations under the development plan in the Leased Lands, the Lessee shall obtain the Mining Supervisor's approval of the development plan. The Mining Supervisor shall not delay unnecessarily in the consideration of a development plan, but he shall take time to consider both technical and environmental provisions of the plan thoroughly prior to approval, and shall hold public hearings on the environmental provisions to assist him in his consideration of the detailed development plan. If the development plan submitted by the Lessee is unacceptable, the Mining Supervisor shall inform the Lessee by written notice of the reasons why the development plan is unacceptable and shall give him an opportunity to amend the plan. If an acceptable development plan is not submitted to the Mining Supervisor by the Lessee within one year after the Lessee's receipt of that notice, the Mining Supervisor shall send a second written notice to the Lessee concerning the unacceptability of the development plan. A failure by the Lessee to submit an acceptable plan within one year after his receipt of the second written notice, without reasonable justification for delay, shall be grounds for termination of the lease, if the Lessor so elects.

Upon approval of the plan, the Lessee shall proceed to develop the Leased Deposits in accordance with the approved plan. After the date of approval of the development plan, the Lessee shall conduct no activities upon the Leased Lands except pursuant to that development plan, or except for necessary activities following a relinquishment under section 28 of this lease or for the disposition of property after termination pursuant to section 32 of this lease.

(b) The Lessee must obtain the written approval of the Mining Supervisor of any change in the plan approved under subsection (a).

(c) The Lessee shall file with the Mining Supervisor annual progress reports describing the operations conducted under the development plan required under subsection (a).

(d) Prior to undertaking any exploratory work on the Leased Lands between the Effective Date and the date of approval of the detailed development plan required by subsection (a) of this section, the Lessee shall file with the Mining Supervisor a plan showing the exploratory work which he proposes to undertake and he shall not commence that work until the Mining Supervisor has approved the plan.

Exploratory work, as used in this subsection, shall include, but not be limited to, seismic work, drilling, blasting, research operations, cross-country travel, the construction of roads and trails and other necessary facilities, and the accumulation of baseline data required under section 1(C) of the Oil Shale Lease Environmental Stipulations. Prior to approval of the detailed development plan under subsection (a) of this section, all exploratory work on the Leased Lands shall be conducted pursuant to a plan approved under this subsection.

Sec. 11. *Protection of the environment; additional stipulations.* (a) The Lessee shall conduct all operations under this lease in compliance with all applicable Federal, State and local water pollution control, water quality, air pollution control, air quality, noise control, and land reclamation statutes, regulations, and standards.

(b) The Lessee shall avoid, or, where avoidance is impracticable, minimize and, where practicable, repair damage to the environment, including the land, the water and air.

(c) The Oil Shale Lease Environmental Stipulations are attached to and specifically incorporated in this lease. A breach of any term of these stipulations will be a breach of the terms of this lease and subject to all the provision of this lease with respect to remedies in case of default.

Sec. 12. *Operations on the Leased Lands; Water Rights.* (a) The Lessee shall exercise reasonable diligence, skill, and care in all operations on the Leased Lands. The Lessee's obligations shall include, but not be limited to, the following:

(1) The Lessee shall conduct all operations on the Leased Lands so as to prevent injury to life, health, or property.

(2) The Lessee shall avoid, or, where avoidance is impracticable, minimize and, where practicable, correct hazards to the public health and safety related to his operations on the Leased Lands.

(3) The Lessee shall avoid wasting the mineral deposits, and other resources, including but not limited to, surface resources, which may be found in, upon, or under such lands.

(b) The Lessee shall conduct all operations on the Leased Lands whether they are surface or underground mining operations, and whether they are in lands in which the Lessor owns the surface or those in which the Lessor has disposed of the surface, in accordance with the provisions of 30 CFR Part 231 and 43 CFR Part 23. Both 30 CFR Part 231 and 43 CFR Part 23 are specifically incorporated by reference into the provisions of this section. The provisions of 43 CFR Part 23 are hereby expressly made applicable to the Lessee's underground mining operations with equal force and effect to that given to those provisions in their application to surface mining operations and to operations on lands in which the Lessor owns the surface.

(c) The Lessee shall take such reasonable steps, and shall conduct operations in such a manner, as may be needed to avoid or, where avoidance is impracticable, to minimize and, where practicable, repair damage to: (1) any forage and timber growth on Federal or non-Federal lands in the vicinity of the Leased Lands; (2) crops, including forage, timber, or improvements of a surface owner; or (3) improvements, whether owned by the United States or by its permittees, licensees, or lessees. The Lessor must approve the steps to be taken and the restoration to be made in the event of the occurrence of damage described in this subsection.

(d) All water rights developed by the Lessee through operations on the Leased Lands shall immediately become the property of the Lessor. As long as the lease continues, the Lessee shall have the right to use those water rights free of charge for activities under the lease.

Sec. 13. *Development by in situ methods.* Where *in situ* methods are used for development of Oil Shale, the Lessee shall not place any entry, well, or opening for such operations within 500 feet of the boundary line of the Leased Lands without the permission of, or unless directed by, the Mining Supervisor, nor shall induced fracturing extend to less than 100 feet from that boundary line.

Sec. 14. *Nuclear fracturing.* No nuclear explosive may be detonated on or in the Leased Lands without the express written approval of the Secretary. The Secretary may approve the detonations of such explosives only after the preparation of an environmental impact statement pursuant to section 102(2) (C) of the National Environmental Policy Act of 1969 (42 U.S.C. § 4332(2)(C)).

Sec. 15. *Inspection and investigation.* The Lessee shall permit any duly authorized officer or representative of the Department at any reasonable time:

(a) to inspect or investigate the Leased Lands and all surface and underground improvements, works, machinery, and equipment, and all books and records pertaining to operations and surveys or investigations under this lease; and

(b) to copy and make extracts from any books and records pertaining to operations under this lease.

Sec. 16. *Reports, maps, etc.* (a) At such times and in such a form as the Lessor may prescribe, the Lessee shall furnish a report with respect to investment and operating costs under this lease. The Lessee shall also submit to the Lessor in such form as the latter may prescribe, not more than 60 days after the end of each quarter of the Lease Year, a report covering that quarter which shall show the amount of each respective mineral or product produced from the Leased Deposits by each method of production used during the quarter, the character and quality thereof, the amount of products and by-products disposed of and price received therefor, and the amount in storage or held for sale. This report shall be certified by the superintendent of the mine, or by some other agency having personal knowledge of the facts who has been designated by the Lessee for that purpose.

(b) The Lessee shall prepare and furnish at such times and in such form as the Lessor may prescribe, maps, photographs, reports, statements and other documents, required by the provisions of 30 CFR Part 231 and 43 CFR Part 23.

Sec. 17. *Notice.* Any notice which is required under this lease shall be given in writing. Where immediate action is required, notice may be given orally or by telegram, but, where this is done, the oral notice shall be confirmed in writing. Wherever this lease requires the Lessee to give notice, notice shall be given to the Mining Supervisor unless this lease requires that notice be given to another officer. The Lessee shall inform the Bureau State Office and the Mining Supervisor of the Lessee's officer to whom notice shall be given.

Sec. 18. *Employment practices.* The Lessee shall pay all wages due persons employed on the Leased Lands at least twice each month in lawful money of the United States. The Lessee shall grant all miners and other employees complete freedom of purchase. The Lessee shall restrict the workday to not more than 8 hours in any one day for underground workers, except in cases of emergency. The Lessee shall employ no person under the age of 16 years in any mine below the surface. If the laws of the State in which the mine is situated prohibit the employment, in a mine below the surface, of persons of an age greater than 16 years, the Lessee shall comply with those laws.

Sec. 19. *Equal Opportunity Clause; certification of non-segregated facilities.* (a) *Equal Opportunity Clause.* During the performance of this lease the Lessee agrees as follows:

(1) The Lessee shall not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Lessee shall take affirmative action to insure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to the following: employment, upgrading, demotion, or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Lessee shall post in conspicuous places, available to employees and applicants for employment, notices to be provided by the Lessor setting forth the provisions of this Equal Opportunity clause.

(2) The Lessee shall, in all solicitations or advertisements for employees placed by or on behalf of the Lessee, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(3) The Lessee shall send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice, to be provided by the Lessor, advising the labor union or workers' representative of the Lessee's commitments under this Equal Opportunity clause, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The Lessee will comply with all provisions of Executive Order No. 11246 of September 24, 1965, as amended, and of the rules, regulations and relevant orders of the Secretary of Labor.

(5) The Lessee shall furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, as amended, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the Secretary of the Interior and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(6) In the event of the Lessee's noncompliance with the Equal Opportunity clause of this lease or with any of the said rules, regulations, or orders, this lease may be canceled, terminated or suspended in whole or in part and the lessee may be declared ineligible for further Federal Government contracts or leases in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, as amended, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, as amended, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) The Lessee shall include the provisions of paragraphs (1) through (7) of this subsection (a) in every contract, subcontract, or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, as amended, so that such provisions will be binding upon each contractor, subcontractor or vendor. The Lessee shall take such action with respect to any contract, subcontract or purchase order as the Secretary may direct as a means of enforcing such provisions, including sanctions for noncompliance: *Provided, however,* That in the event the Lessee becomes involved in, or is threatened with, litigation with a contractor, subcontractor or vendor as a result of such direction by the Secretary, the lessee may request the lessor to enter into such litigation to protect the interests of the lessor.

(b) *Certification of non-segregated facilities.* By entering into this lease, the Lessee certifies that Lessee does not and shall not maintain or provide for Lessee's employees any segregated facilities at any of Lessee's establishments, and that Lessee does not and shall not permit Lessee's employees to perform their services at any location, under Lessee's control, where segregated facilities are maintained. The Lessee agrees that a breach of this certification is a violation of the Equal Opportunity clause in this lease. As used in this certification, the term "segregated facilities" means, but is not limited to, any waiting rooms, work areas, rest rooms and wash rooms, restaurants and other eating areas, time clocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, color, religion, or national origin, because of habit, local custom, or otherwise. Lessee further agrees that (except where Lessee has obtained identical certifications from proposed contractors and subcontractors for specific time periods) Lessee shall obtain identical certifications from proposed contractors and subcontractors prior to the award of contracts or subcontracts exceeding $10,000 which are not exempt from the provisions of the Equal Opportunity clause; that Lessee shall retain such cerifications in Lessee's files and shall make them available to the Secretary at his request; and that Lessee shall forward the following notice to such proposed contractors and subcontractors (except where the proposed contractor or subcontractor has submitted identical certifications for specific time periods): Notice to prospective contractors and subcontractors of requirements for certification of non-segregated facilities. A Certification of Non-segregated Facilities, as required by the May 9, 1967, order (32 FR 7439, May 19, 1967) on Elimination of Segregated Facilities, by the Secretary of Labor, must be submitted prior to the award of a contract or subcontract exceeding $10,000 which is not exempt from the provisions of the Equal Opportunity clause. The certification may be submitted either for each contract and subcontract or for all contracts and subcontracts during a period (i.e., quarterly, semi-annually, or annually).

Sec. 20. *Taxes.* The Lessee shall pay, when due, all taxes lawfully assessed and levied under the laws of the State or the United States upon improvements, output of mines, or other rights, property, or assets of the Lessee.

Sec. 21. *Monopoly and fair prices.* The Lessor reserves full authority to promulgate and enforce orders and regulations under the provisions of sections 30 and 32 of the Act (30 U.S.C. §§ 187 and 189) necessary to insure that any sale of the production from the Leased Deposits to the United States or to the public is at reasonable prices, to prevent monopoly, and to safeguard the public welfare, and such regulations shall, upon promulgation, be binding upon the Lessee.

Sec. 22. *Suspension of operations or production.* Any suspension of operations or production under section 39 of the Act (30 U.S.C. § 209) granted with respect to this lease shall take effect as of the first day of the calendar month following the calendar month during which the suspension is approved, except that, in a situation where in the opinion of the Mining Supervisor there is an immediate danger to life, or of irreparable major damage to property or the environment, the Mining Supervisor may grant a suspension effective immediately. The term of any suspension granted pursuant to the Lessee's request with respect to operations or production under this lease shall be in full calendar months. A suspension shall terminate either at the time designated in the suspension order or, if there is no time of termination in the order, at such time as the Mining Supervisor shall designate in subsequent notice to the Lessee.

Sec. 23. *Readjustment of terms and conditions.* The Lessor may propose the reasonable readjustment of the terms and conditions of this lease (including royalty provisions), the first readjustment to be effective at the twentieth Anniversary Date of this lease and subsequent readjustments to be effective at twenty Lease Year intervals thereafter. At least 120 days before the appropriate Anniversary Date the Lessor shall give notice to the Lessee of any proposed readjustment of the terms and conditions of the lease and the nature thereof, and, unless the Lessee, within 60 days after receipt of such notice, files with the Lessor an objection to the proposed terms or relinquishes the lease as of the appropriate Anniversary Date, the Lessee shall be deemed conclusively to have agreed to such terms and conditions. If the Lessee files objections with the Lessor, and agreement cannot be reached between the Lessor and the Lessee within a period of 60 days after the filing of the objections, the lease may be terminated by either party upon giving 60 days' notice to the other party; however, the Lessor's right to terminate the lease shall be suspended by the Lessee's filing of a notice of appeal pursuant to section 34 of this lease. If the Lessee files objections to the proposed readjusted terms and conditions, the existing terms and conditions (other than those concerning royalties) shall remain in effect until there has been an agreement between the Lessor and the Lessee on the new terms and conditions to be incorporated in the lease, or until the Lessee has exhausted his rights of appeal under section 34 of this lease, or until the lease is terminated; however, the readjusted royalty provisions shall be effective until there is either agreement between the Lessor and the Lessee or until the lease is terminated. If the readjusted royalty provisions are subsequently rescinded or amended, the Lessee shall be permitted to credit any excess royalty payments against royalties subsequently due to the Lessor.

Sec. 24. *Assignment.* With respect to the assignment or transfer of an interest under this lease, the Lessee shall comply with the provisions of 43 CFR Subpart 3506 to the same extent as if that Subpart were specifically applicable to oil shale leases. The Lessor shall have no discretion to refuse to approve an assignment except: (1) where the assignee is not qualified to hold a lease under section 1 of the Act (30 U.S.C. § 181); (2) where the assignee is unable to provide an adequate bond; or (3) where either the assigned or the retained portion of the lease would, in the opinion of the Lessor, be too small to be economically developed.

Sec. 25. *Overriding royalties.* The Lessee shall not create, by assignment or otherwise, an overriding royalty interest in excess of 25 percent of the rate of royalty payable to the United States under this lease or an overriding royalty interest which when added to any other outstanding overriding royalty interest exceeds that percentage, except that, where an interest in the leasehold or in an operating agreement is assigned, the assignor may retain an overriding royalty interest in excess of the above limitation if he shows to the satisfaction of the Department that he has made substantial investments for improvements on the lands covered by the assignment.

Sec. 26. *Heirs and successors in interest.* Each obligation hereunder shall extend to and be binding upon, and every benefit shall inure to, the heirs, executors, administrators, successors, or assigns of the respective parties hereto.

Sec. 27. *Unlawful interest.* No member of, or Delegate to, Congress or Resident Commissioner, after his election or appointment, either before or after he has qualified and during his continuance in office, and no officer, agent, or employee of the Department of the Interior, except as provided in 43 CFR 7.4(a)(1), shall be admitted to any share or part in this lease or derive any benefit that may arise therefrom; and the provisions of Section 3741 of the Revised Statutes of the United States (41 U.S.C. § 22), as amended, and sections 431, 432, and 433, Title 18 of the United States Code, relating to contracts, enter into and form a part of this lease so far as the same may be applicable.

Sec. 28. *Relinquishment of lease.* (a) Upon showing to the satisfaction of the Lessor that he has complied with the terms and conditions of this lease, the Lessee may relinquish the entire lease or any legal subdivision of the Leased Lands.

(b) A relinquishment must be filed, in duplicate, in the proper Bureau State Office. Upon its acceptance it shall be effective as of the date it is filed, subject to the continued obligation of the lessee and his surety, in accordance with the terms and conditions of this lease, (1) to make payment of all accrued bonus payments, rentals, and royalties, except as provided in section 5; (2) to provide for the preservation of any mines, *in situ* production works, underground development works, other permanent improvements, and other property, whether fixtures or personalty, on the Leased Lands; (3) to provide for the reclamation of lands and water affected by exploration or mining operations under this lease; and (4) to comply with all other applicable requirements of this lease.

Sec. 29. *Remedies in case of default.* If the Lessee shall fail to comply with any of the terms and conditions of this lease (including the terms and conditions of any development plan approved under section 10) and that default shall continue for a period of 30 days after service of notice thereof by the Lessor, the Lessor may (1) suspend operations until the required action is taken to correct noncompliance, or (2) institute appropriate proceedings in a court of competent jurisdiction for the forfeiture and cancellation of this lease as provided in section 31 of the Act (30 U.S.C. § 188) and for forfeiture of any applicable bond. If the Lessee fails to take prompt and necessary steps to prevent loss or damage to the mine, property, or premises, or to prevent danger to the employees, or to avoid, or, where avoidance is impracticable, to minimize and, where practicable, repair damage to the environment, or, if immediate action by the Lessor, without waiting for action by the Lessee, is required for any of those purposes, the Lessor may enter on the premises and take such measures as he may deem necessary to prevent such loss, damage, or danger, or to correct the damaging, dangerous, or unsafe condition of the mine or any other facilities upon the Leased Lands, and those measures shall be at the expense of the Lessee.

Sec. 30. *Effect of waiver.* A waiver of any breach of the provisions of this lease shall extend only to that particular breach and shall not limit the rights of the parties with respect to any future breach. A waiver of a particular cause of forfeiture shall not prevent cancellation of this lease for any other cause, or for the same cause occurring at another time.

Sec. 31. *Delivery of premises in case of forfeiture.* In case of the termination of this lease in any manner the Lessee shall deliver to the Lessor, in the condition required by the reclamation requirements of approved exploration and development plans, and subject to the provisions of section 32 of this lease, the Leased Lands, including permanent improvements and other property on the Leased Lands, whether affixed to the ground or movable, and all underground shafts and timbering, well casing, and such other supports and structures as are necessary for the preservation of the Leased Lands, or any mines, other underground development works, or deposits in the Leased Lands.

Sec. 32. *Disposition of property upon termination of lease.* (a) Upon termination of this lease in any manner all underground timbering and any other supports or structures which the Lessor shall inform the Lessee are necessary for the preservation of any mines or other underground development works shall become and remain thereafter a part of the realty without the payment of any compensation to the Lessee. All other structures, equipment, machinery, tools, appliances, and materials on the Leased Lands, whether affixed to the ground or movable, shall remain the property of the Lessee upon the termination of this lease, but the Lessee shall have no right, for a period of six months following the termination, to remove from the Leased Lands any of that property which in the opinion of the Lessor is useful for the protection of the Leased Lands (including any mines in those lands) unless the Lessor shall expressly authorize the removal. During the six-month period the Lessor shall have the right to purchase at the appraised value any or all items of that property required or useful for the protection of the Leased Lands. The appraised value shall be fixed by three disinterested and competent persons (one to be designated by the Lessor, one by the Lessee, and the third by the two so designated), and the appraised value determined by the three or a majority of them shall be conclusive.

(b) At any time within a period of 90 days after either the Lessor has informed the Lessee that he will not purchase the property or the expiration of the 6-month period, the Lessee shall have the right to remove from the premises the property which was not purchased by the Lessor.

(c) Any structures, machinery, equipment, tools, appliances, and materials, subject to removal by the Lessee as provided above, which are allowed to remain on the Leased Lands shall become the property of the Lessor on expiration of the 90-day period or any extension of that period which may be granted by the Lessor because of adverse climatic conditions or other good and sufficient reason, unless the Lessor shall direct the Lessee to remove any or all of such property on expiration of the 90-day period. If the Lessor directs the Lessee to remove such property, the Lessee shall do so at his own expense or, if he fails to do so within a reasonable period, the Lessor may do so at the Lessee's expense.

Sec. 33. *Protection of proprietary information.* (a) This lease, and any activities thereunder, shall not be construed to grant a license, permit or other right of use or ownership to the Lessor, or any other person, of the patented processes, trade secrets, or other confidential or privileged technical information (hereafter in this section called "technical processes") of the Lessee or any other party whose technical processes are embodied in improvements on the Leased Lands or used in connection with the lease. Notwithstanding any other provision of this lease, the Lessor agrees that any technical processes obtained from the Lessee which are designated by the Lessee as confidential shall: (1) not be disclosed to persons other than employees of the Federal Government having a need for such disclosures; (2) not be copied or reproduced in any manner except as required specifically by the Mining Supervisor; and (3) not be used in any manner that will violate their proprietary nature unless the Mining Supervisor shall make a written determination that such technical processes do not contain trade secrets or are not confidential, or unless such disclosure is required by statute; provided however, that before any such publication or disclosure, except where the overriding national interest demands otherwise, the Mining Supervisor shall notify the Lessee of the proposed disclosure and those to whom the disclosure will be made, provide a copy of the written determination, and allow the Lessee 30 days to submit additional material supporting its claim of confidentiality or otherwise to initiate an appeal from the decision of the Mining Supervisor prior to any disclosure.

(b) In the event the lease is terminated and the Lessor elects pursuant to section 32 to purchase machinery or equipment the use of which would involve technical processes in the operations of the purchased machinery, the Lessor shall have the right to use those technical processes in the operations of the purchased machinery or equipment; provided that (1), with respect to third parties' technical processes which the Lessee has obtained the right to use by contract or agreement, the Lessor shall replace the Lessee as a party to the contract or agreement, and (2) with respect to technical processes owned, developed or controlled by the Lessee itself, the Lessor shall agree to pay the Lessee fair market value for use of the Lessee's technical processes in said operations. Any contract or agreement into which the Lessee shall enter with a third party for the right to use technical processes belonging to that third party shall provide that the Lessor may become a party to that contract or agreement to the extent that those processes may be used for the protection of the Leased Lands. If the Lessee and the Lessor shall not agree as to the fair market value of the Lessee's technical processes, that value shall be determined as provided in section 32(a) for other property acquired by the Lessor upon termination of the lease.

Sec. 34. *Lessee's liability to the Lessor.* (a) The Lessee shall be liable to the United States for any damage suffered by the United States in any way arising from or connected with Lessee's activities and operations conducted pursuant to this lease, except where damage is caused by employees of the United States acting within the scope of their authority.

(b) The Lessee shall indemnify and hold harmless the United States from any and all claims arising from or connected with Lessee's activities and operations under this lease.

(c) In any case where liability without fault is imposed on the Lessee pursuant to this section, and the damages involved were caused by the action of a third party, the rules of subrogation shall apply in accordance with the law of the jurisdiction where the damage occurred.

Sec. 35. *Appeals.* The Lessee shall have the right of appeal (a) under 43 CFR 3000.4 from any action or decision of any official of the Bureau, (b) under 30 CFR 231.74 from any action, order, or decision of any official of the Geological Survey, or (c) under applicable regulation from any action or decision of any other official of the Department, arising in connection with this lease, including any action or decision pursuant to section 23 of this lease with respect to the readjustment of terms and conditions.

Sec. 36. *Interpretation of this lease.* (a) The paragraph headings in this lease are for convenience only, and do not purport to, and shall not be deemed to, define, limit, or extend the scope or intent of the paragraph to which they pertain.

(b) As used in this lease, unless the context clearly indicates otherwise, a word in the masculine or neuter form shall be interpreted as equally applicable to the masculine, feminine, and neuter genders, and words in singular form shall be interpreted as equally applicable to singular and plural numbers.

THE UNITED STATES OF AMERICA

By ____________________

____

(Title)

Witnesses to Signature of Lessee(s) _______

(Date)

_______________ ________________________

(Signature of Lessee)

_______________ ________________________

(Signature of Lessee)

_______________ ________________________

(Signature of Lessee)

Oil Shale Lease Environmental Stipulations

Section 1. *General.* (A) *Applicability of Stipulations.* The terms, conditions, requirements and prohibitions imposed upon Lessee by these Stipulations are also imposed upon Lessee's agents, employees, contractors, and sub-contractors, and their employees. Failure or refusal of Lessee's agents, employees, contractors, sub-contractors, or their employees to comply with these Stipulations shall be deemed to be the failure or refusal of the Lessee. Lessee shall require its agents, contractors, and sub-contractors to include these Stipulations in all contracts and sub-contracts which are entered into by any of them, together with a provision that the other contracting party, and its agents, employees, contractors and sub-contractors, and the employees of each of them, shall likewise be bound to comply with these stipulations.

(B) *Changes in Conditions.* These Stipulations are based on existing knowledge and technology. They may be revised or amended by mutual consent of the Mining Supervisor, the Bureau District Manager, and the Lessee at any time to adjust to changed conditions or to correct an oversight. The Lessor may amend these stipulations at any time without the consent of the Lessee in order to make these stipulations consistent with any new Federal or State statutes for the protection of the environment upon their enactment and with regulations issued under those statutes. The Lessee, the Mining Supervisor, and the Bureau District Manager shall meet at least once a year to review advances in technology and, in a mutual endeavor, weigh, and decide the feasibility and need of revising or amending existing Stipulations.

The Lessor and the Lessee agree that, in this mutual endeavor to decide upon the feasibility and need for amending the existing Stipulations, they will act in good faith and in a sincere effort to make the Lessee's activities under the lease as free from environmental damage as is practicable. Toward this end, systems which require pollution control devices shall possess sufficient flexibility to adopt improved technology at practicable intervals and shall be constructed with the understanding that continued compliance with changing pollution control laws is required.

(C) *Collection of Environmental Data and Monitoring Program.* (1) The Lessee shall compile data to determine the conditions existing prior to any development operations under the lease and shall, except as provided below, conduct a monitoring program before, during, and subsequent to development operations. The Lessee shall conduct the monitoring program to provide a record of changes from conditions existing prior to development operations, as established by the collection of baseline data, a continuing check on compliance with the provisions of the lease (including these attached Stipulations) and all applicable Federal, State, and local environmental protection and pollution control requirements, timely notice of detrimental effects and conditions requiring correction, and a factual basis for revision or amendment of these Stipulations pursuant to Section 1(B) hereof. Both the types of baseline and subsequent data required and the methods to be used for the collection of the baseline data and the conduct of the monitoring program shall be those set forth in paragraph (2) of this subsection. Once the monitoring program has begun the baseline data shall be collected continuously as long as the Mining Supervisor shall require under paragraph (2) of this subsection. The baseline data shall be conducted for at least one full year prior to the submission of the detailed development plan under section 10(a) of this lease. The plan shall, at the discretion, or with the approval, of the Mining Supervisor, be modified at any time as necessary as a result of study of the baseline data obtained after the submission of the plan. Exploratory operations, as approved by the Mining Supervisor, shall be permitted during the collection of the baseline data. All records of baseline data and subsequent monitoring required by this subsection shall be submitted to the Mining Supervisor at intervals to be prescribed by him.

(2) In collecting baseline data and conducting a monitoring program the Lessee shall adopt the following methods and shall collect the information required below. Wherever the number and placing of testing installations are not given, they shall be as determined by the Lessee, but subject to being changed as required by the Mining Supervisor. The monitoring program shall, thereafter, be conducted until the Mining Supervisor has determined to his satisfaction that environmental conditions have been established after the termination of development operations which are consistent with the requirements of applicable Federal and State statutes and regulations; however, the Mining Supervisor may terminate this requirement at an earlier date where it is in the public interest.

(a) *Surface water.* The Lessee shall construct gauging stations on the major drainages on the Leased Lands and, as required by the Mining Supervisor, upstream and downstream from the Leased Lands. Data collected at the stations shall include continuous streamflow records, continuous water temperature records, periodic analyses for selected inorganic and organic chemical constituents, as directed by the Mining Supervisor, continuous precipitation records, and continuous sediment records. The Lessee shall maintain records of all information obtained under this paragraph (2)(a).

(b) *Ground water.* At each proposed or actual mine site, the Lessee shall drill a test well and shall install an observation well in each water-bearing zone defined by the test well. The Lessee shall collect samples of drill cuttings and shall make borehole geophysical logs as directed by the Mining Supervisor. The lessee shall isolate each water-bearing zone penetrated by the test wells and pump each of the zones for the period required by the Mining Supervisor. During pump tests the Lessee shall record the water-level fluctuations in each of the observation wells, maintain steady, continuous discharge from the test well, and record the discharge measurements. The Lessee shall maintain records of water level and temperature on each test well and on each observation well pursuant to a measurement schedule specified by the Mining Supervisor. At the initial pump test of each well the Lessee shall determine the water quality of that well by analyzing water samples for organic and inorganic chemical constituents, including, without limitation, trace constituents subject to drinking water standards and water pollution control regulations. The Mining Supervisor may require analysis of samples for such additional constituents as he may deem desirable. After the initial test, the Lessee shall collect water samples from each well at six-month intervals and analyze them for evidence of trends in water quality as determined by comparing the samples with previous analyses.

The Lessee shall complete one observation well upgradient from each spent shale disposal site and at least two observation wells downgradient from the site at depths and locations specified by the Mining Supervisor. The Mining Supervisor may require additional observation wells if there is evidence that they are needed to provide adequate monitoring of the water quality of an aquifer. The Lessee shall record water levels and temperatures in each observation well pursuant to a measurement schedule established by the Mining Supervisor. The Lessee shall determine the water quality of each observation well by analyzing samples for organic and inorganic chemical constituents, including, without limitation, trace constituents subject to drinking water standards and water pollution controls. The Mining Supervisor may require analysis of samples for such additional constituents as he may deem desirable. After the initial test of an observation well the Lessee shall collect water samples from the well at six-month intervals and analyze them for evidence of trends in water quality as determined by comparing the samples with previous analyses.

The Lessee shall maintain records of all information obtained under this paragraph (2)(b).

(c) *Air Quality*. In the collection of baseline data, the Lessee shall monitor air quality over at least 90 percent of each lease year, during which monitoring is required, using four strategically-located stations. One of the stations shall be at the expected point of maximum concentrations, or as close to that expected point of maximum concentration as feasible.

The Lessee shall monitor air quality for sulphur dioxide, hydrogen sulphide, and suspended particulates, using automatic instruments with continuous recorders, when applicable. The Lessee shall also monitor, under the same conditions, hydrocarbons, oxides of nitrogen, and other pollutants, where the Mining Supervisor has determined that such monitoring is necessary to determine baseline air quality or to conduct an effective monitoring program. In addition, the Lessee shall establish a meteorological station in reasonable proximity to each proposed plant site to monitor, at least 95 percent of the time over each lease year during which monitoring is required, wind direction and speed (vane and anemometer) and humidity at three levels, one at least 100 feet above the surface of the plant site, one at approximately 30 feet above the surface of the plant site, and one at ground level, and temperature at two levels, one at least 100 feet above the surface of the plant site, and one at approximately 30 feet above the surface of the plant site. The Lessee shall maintain records of all baseline data collection and monitoring programs.

(d) *Flora and Fauna*. The Lessee shall make studies of the flora and fauna of the leased lands and of all other lands lying within a mile of the leased lands, and of all lands to be used for disposal of residues from mining and processing oil shale and also of the aquatic habitat as far downstream as the Mining Supervisor shall require. These studies will determine the distribution and density of the flora in these areas and periodically determine the condition of such flora. These studies shall also determine the species of fauna, their distribution, and their abundance at bi-monthly intervals. The Lessee shall submit a report to the Mining Supervisor of the baseline data obtained and, during the monitoring program, shall submit semi-annual reports to the Mining Supervisor showing whether or not there has been any change. The Lessee shall also study, and report to the Mining Supervisor on ecological interrelationships including migratory patterns of birds, mammals, and fish, and plant animal relationships. The Lessee shall compile an inventory of natural surface water features, such as springs and seeps.

(e) *Soil Survey and Productivity Assessment*. The Lessee shall conduct a soil survey and productivity assessment of all portions of the Leased Lands proposed to be disturbed under the detailed development plan. This survey must include the preparation of maps, tables, and reports describing soil types, depth of the various layers of soil, but not more than a depth of 50 feet from the surface to be disturbed, strike and dip of the material, slopes, solar exposure, vegetative cover, and erodability.

(3) The environmental monitoring program shall be an integral part of the detailed development plan required in Section 10 of the lease, and at the time of the submission of the plan the Lessee shall provide the Mining Supervisory with a complete compilation of the baseline data collected above and the record of the monitoring program for any period subsequent to the conclusion of that compilation.

(4) Not more than one year after obtaining approval of the detailed mining plan and on each subsequent anniversary date the Lessee shall submit to the Mining Supervisor a report of the baseline data collected and a report of the monitoring programs as a part of the required annual progress reports on the development program. This portion of the annual report will be subject to public review and comment.

(D) *Emergency Decisions*. Any decisions or approvals of the Mining Supervisor required by these Stipulations to be in writing may in emergencies be issued orally, with written confirmation as soon thereafter as possible.

(E) *Environmental Briefing*. During the life of this Lease, Lessee shall provide that such Federal and State employees as may be designated by the Mining Supervisor shall brief personnel on environmental and other pertinent matters. The Lessee shall provide for such briefings upon the request of the Mining Supervisor, but the Mining Supervisor shall request only such briefings as may be reasonably necessary to effectuate the provisions of this Lease. Lessee shall make arrangements for the time, place, and attendance at such briefings. Lessee shall bear all costs of such briefings other than salary, per diem, subsistence and travel costs of Federal and State employees.

(F) *Construction Standards*. The general design of all buildings and structures shall comply with the latest edition of the Uniform Building Code (U.B.C.). Structural steel shall be designed in accordance with the latest edition of the American Institute of Steel Construction "Specifications for Design, Fabrication and Erection of Structural Steel for Buildings." Reinforced concrete shall comply with the latest edition of the American Concrete Institute's Building Code Requirements for Reinforced Concrete." Engineering works for impoundments shall conform to standard engineering practice sufficient to withstand the 100-year flood in the drainage in which installed.

(G) *Housing and Welfare of Employees*. In the exercise of his right under section 2 of the Lease to construct buildings and other facilities for the housing and welfare of his employees, the Lessee shall at all times make certain that these facilities are situated, constructed, operated, and maintained in an orderly manner, satisfactory to the Mining Supervisor. While no general restriction is imposed upon the construction of facilities necessary to the employees' health and well-being, such construction shall be subject to the Mining Supervisor's approval and shall not unreasonably damage the environment of the leased lands.

(H) *Posting of Stipulations and Plans*. The Lessee shall insure that copies of these Stipulations and any approved exploration and development plans are available at the operating sites and for inspection by all on-the-ground operating personnel.

SEC. 2. *Access and Service Plans*. (A) *Transportation Corridor Plans*. The Lessee shall provide corridor plans for roads, pipelines and utilities on the Leased Lands for approval by the Mining Supervisor. Each plan shall include probable major design features and plans for the protection of the environment, prevention of pollution, minimization of erosion, rehabilitation and revegetation of all disturbed areas not required in operation of the transportation system, both during and after construction. The Lessee shall, to the maximum extent practicable, make use of multi-use corridors for roads, pipelines and utilities.

(B) *Regulation of Public Access*. After road construction is completed, the Lessee shall, upon consultation with the Lessor, permit reasonable, free and unrestricted public access to and upon the road and rights-of-way for all lawful and proper purposes except in plant sites, mine sites, disposal areas, and other operational areas which may be closed to the general public. The Lessee shall regulate public access and public vehicular traffic as required to facilitate operations and to protect the public and, to the extent reasonable, livestock and wildlife from hazards associated with construction. For this purpose the Lessee shall provide warnings, flagmen, barricades, and other safety measures as necessary. Whenever the Mining Supervisor shall determine that the Lessee's regulation of access and traffic is unreasonable, or that the Lessee's provision of safety measures is inadequate, he shall so inform the Lessee who shall immediately take corrective measures.

(C) *Existing and Planned Roads and Trails*. Where feasible, the Lessee shall use existing roads and trails. Unless the Mining Supervisor shall direct otherwise, roads and trails shall be located, constructed, maintained, and closed according to the specifications of the Bureau of Land Management and shall include drainage structures where needed.

(D) *Waterbars and Breaks*. The Lessee shall divert runoff from roads and uphill slopes by means of waterbars, waterbreaks, or culverts constructed in accordance with Bureau specifications.

(E) *Pipeline Construction Standards*. In the design and construction of oil pipelines and the choice of materials for them, the Lessee shall follow the standards (wherever they may be made applicable) established by the Department of Transportation and, if these standards should ever be revised, supplemented, or superseded, shall follow the new standards in new construction. These standards include:

(1) 49 CFR 192, Transportation of Natural and Other Gas by Pipeline; and

(2) 49 CFR 195, Transmission of Liquids by Pipeline.

(F) *Pipeline Safety Standards*. The Lessee shall meet, where applicable, the safety standards and reporting requirements set forth in the following, as now in effect and as hereafter amended, or, if these regulations should be superseded, the regulations or other rules superseding them:

(1) 49 CFR, Part 110, Carriers by Pipeline (Other than Natural Gas and Water);

(2) 49 CFR, Part 192, Transportation of Natural and Other Gas and Water);

(3) 49 CFR, Part 195, Transmission of Liquids by Pipeline;

(G) *Shut-Off Valves*. The Lessee shall insure that oil transportation pipeline designs provide for automatic shut-off valves at each pumping or compressor station and such additional valves as may be necessary in view of:

(1) Terrain and drainage systems traversed;
(2) Population centers;
(3) Wildlife and fishery habitat;
(4) Public water supplies and significant water bodies;
(5) Hazardous geologic areas; and
(6) Scenic Values.

The Lessee shall install any additional valves required by the Mining Supervisor.

(H) *Pipeline Corrosion*. With regard to oil transportation pipelines, the Lessee shall submit detailed plans to the Mining Supervisor for corrosion-resistant design and methods for early detection of pipeline corrosion. These shall include: (1) pipe material and welding techniques to be used and information on their particular suitability for the environment involved; (2) details on the external pipe protection to be provided (coating, wrapping, etc.), including information on variation of the coating process to cope with variations in environmental factors; (3) plans for cathodic protection including details of impressed ground sources and controls to insure continuous maintenance of adequate protection over the entire surface of the pipe; (4) details of plans for monitoring cathodic protection current including spacing of current monitors; and (5) provision of periodic surveys of trouble spots, regular preventive maintenance surveys, regular surveys for external and internal deterioration which may result in failure, and special provisions for abnormal potential patterns resulting from crossings with other pipelines or cables.

(I) *Electric Transmission Facilities*. The Lessee shall design and construct telegraph, telephone, electric powerlines, distribution lines and other transmission facilities in accordance with the guidelines set forth in "Environmental Criteria for Electric Transmission System" (U.S.D.I., U.S.D.A., 1970), as now or in the future amended, or if these guidelines should be superseded, in the guidelines or other rules superseding them. Distribution lines shall be designed and constructed in accordance with REA Bulletin 61-10 (Powerline Contacts by Eagles and other Large Birds), as now or in the future amended, or, if these guidelines should be superseded, in the guidelines or other rules superseding them.

(J) *Natural Barriers*. Where a road or exploratory site cuts a natural barrier used for livestock control, the Lessee shall, at his own expense, close the opening by the use of a fence or other suitable barrier meeting Bureau standards.

(K) *Specifications for fences, and Cattleguards*. Fences and cattleguards constructed by the Lessee shall meet established Bureau specifications and standards.

(L) *Crossings*. The Lessee shall take all steps necessary to make certain that roads constructed under this lease do not prevent or unreasonably disrupt the use of existing roads, foot trails, pipelines, and other rights-of-way or major animal migration routes. This requirement shall include the construction of suitable overhead or underground crossings where they are determined to be necessary by the Mining Supervisor.

(M) *Alternate Routes*. If during construction the Lessee's activities shall interfere with the free use of existing roads and trails used by persons, whether or not recorded, he shall provide such alternate roads and trails as the Mining Supervisor may determine to be needed.

(N) *Off-Road Vehicle Use*. The Lessee shall use off-road vehicles in a manner consistent with applicable regulations.

Sec. 3. *Fire Prevention and Control*. (A) *Instructions of the Mining Supervisor*. (1) The Lessee shall comply with the instructions and directions of the Mining Supervisor concerning the use, prevention and suppression of fires, and shall make every reasonable effort to prevent, control and suppress any fire on land subject to the lease. Uncontrolled fires must be immediately reported to the Mining Supervisor.

(2) (a) The Lessee shall construct fire lines or perform clearing when determined by the Mining Supervisor to be necessary for forest, brush and grass fire prevention.

(b) The Lessee shall comply with the National Fire Codes on handling, transportation, storage, use and disposal of flammable liquids, gases, and solids.

(c) The Lessee shall take all appropriate actions to prevent oil shale outcrop fires.

(B) *Liability of Lessee*. The control and suppression of any fires on the Leased Lands (or on adjoining public lands which have spread from the Leased Lands) caused by the Lessee or his employees, contractors, subcontractors, or agents shall be at the expense of the Lessee. Upon the failure of the Lessee to control and suppress such fires in a manner satisfactory to him, the Mining Supervisor shall take such steps as are necessary to control and suppress the fire, either alone or in conjunction with other Federal, State, and local authorities, and the cost of such control and suppression shall be borne by the Lessee.

Sec. 4. *Fish and Wildlife*. (A) *Management Plan*. The Lessee shall submit for approval by the Mining Supervisor, as part of the exploration and mining plan, a detailed fish and wildlife management plan which shall include the steps which the Lessee shall take to: (1) avoid or, where avoidance is impracticable, minimize damage to fish and wildlife habitat, including water supplies; (2) restore such habitat in the event it is unavoidably destroyed or damaged; (3) provide alternate habitats; and (4) provide controlled access to the public for the enjoyment of the wildlife resources on such lands as may be mutually agreed upon. The plan shall include, but not be limited to, detailed information on activities, time schedule, performance standards, proposed accomplishments, and ways and means of avoiding or minimizing environmental impacts on fish and wildlife.

(B) *Mitigation of Damage*. Wherever destruction or significant disturbance of fish and wildlife habitat is inevitable, the Lessee shall submit, for the Mining Supervisor's approval at least 60 days prior to the destruction or damage of the habitat, those measures which the Lessee proposes to take to comply with the requirement of 30 CFR 231.4(b), as now in effect or as hereafter amended, or, if that regulation should be superseded, the regulations or other rules superseding it, to avoid, or, where avoidance is impracticable, minimize and repair, injury or destruction of fish and wildlife and their habitat. As a general rule, the proposed measures should provide for habitat of similar type and equal in quantity and quality to that destroyed or damaged. The Mining Supervisor shall, within 60 days after the submission of the proposed measures to him, either approve or disapprove them. If he shall approve them, the Lessee shall execute the proposed measures for the mitigation of the destruction or damage of the habitat. If the Mining Supervisor shall disapprove the measures, he shall offer the Lessee an opportunity for consultation at which, whenever possible, he shall inform the Lessee of any changes which will make the measures acceptable.

(C) *Big Game*. The Lessee shall construct big game drift fences when and where necessary to direct big game movements around or away from oil shale development areas.

(D) *Posting of Notices*. The Lessee shall post in reasonable and conspicuous places notices informing its employees, agents, contractors, subcontractors, and their employees of all applicable laws and regulations governing hunting, fishing, and trapping.

Sec. 5. *Health and Safety*. (A) *In General*. The Lessee shall take all measures necesary to protect the health and safety of all persons affected by it activities and operations and shall immediately abate any activity or condition which threatens the life of any person or which threatens any peron with bodily harm.

(B) *Compliance with Federal Health and Safety Laws and Regulations*. The Lessee shall comply with the Federal Metal and Nonmetallic Mine Safety Act of 1966 (30 U.S.C. §§ 721-740), as now in effect or as hereafter amended, or, if it should be superseded, with the statute superseding it, and the Occupational Health and Safety Act of 1970 (29 U.S.C. §§ 651-678), a now in effect, or as hereafter amended, or, if it should be superseded, with the statute superseding it, and all health and safety standards promulgated pursuant thereto.

(C) *Use of Explosives*. The Lessee shall insure that all blasting operations, including the purchase, handling, transportation, storage, use, and destruction of blasting agents are performed in conformance with Public Law 91-452, October 15, 1970 (18 U.S.C. §§ 841-848), as now in effect or as hereafter amended, or if it should be superseded, with the statute superseding it, and the regulations promulgated thereunder which are now in 26 CFR 181.

Sec. 6. *Historic and Scientific Values*. (A) *Cultural Investigations*. The Lessee shall, prior to construction or mining, conduct a thorough and professional investigation of any portion of the Leased Lands to be used, including, but not limited to, those to be used for mining, processing, or disposal operations or roads, for objects of historic or scientific interest, including, but not limited to, Indian ruins, pictographs and other archeological remains. The Lessee shall report the results of these investigations of the Mining Supervisor before commencing construction and mining operations.

(B) *Objects of Historic or Scientific Interest*. The Lessee shall not in any activities under this lease appropriate, remove, injure, deface, or alter any object of antiquity, or of historic, prehistoric, or scientific interest, including, but not limited to, Indian ruins, pictographs, and other archeological remains. Where a question exists as to whether or not an object is of historic, prehistoric, or scientific interest or is an object of antiquity, the Lessee shall report to the Mining Supervisor for a final determination of which he shall inform the Lessee without unnecessary delay.

Sec. 7. *Oil and Hazardous Materials.* (A) *Spill Contingency Plans.* The Lessee agrees to submit spill contingency plans to the Mining Supervisor with the detailed development plan. This plan shall provide for the control of spills of oil or other hazardous substances which for purposes of this Section 7 shall be defined in section 311(a)(14) of the Federal Water Pollution Control Act, as amended (86 Stat. 816, 863), as now in effect or as hereafter amended, or if it should be superseded, the statute superseding it.

The plans shall conform to this Stipulation and the National Oil and Hazardous Substances Pollution Contingency Plan, 36 FR 16215, August 20, 1971, as now in force or as hereafter amended, or, if it shall be superseded, the document superseding it, and shall: (1) include a description of positive spill prevention efforts which the lessee shall make; (2) include provisions for spill control; (3) provide for immediate corrective action including spill control and restoration of the affected resource; (4) provide that the Mining Supervisor shall approve any materials or devices used for spill control and shall approve any disposal sites or techniques selected to handle spilled matter; and (5) include separate and specific techniques and schedules for cleanup of spills on land, rivers and streams. As used in this Stipulation, spill control is defined as including detection, location, confinement, and cleanup of the spill.

(B) *Responsibility.* If, during operations, any oil or other hazardous substance should be discharged, the control, removal, disposal, and cleanup of that substance, wherever found, shall be the responsibility of Lessee. Upon the failure of the Lessee to control, remove, dispose of, or clean up the discharge, or to repair all damages resulting therefrom, the Mining Supervisor may take such measures as he deems necessary to control, remove, dispose of, or clean up the discharge and restore the area, including, where appropriate, the aquatic environment and fish and wildlife habitats, at the full expense of the Lessee. Such action by the Mining Supervisor shall not relieve Lessee of any responsibility as provided in this lease.

(C) *Reporting of Spills and Discharges.* The Lessee shall give immedaite notice of any spills or discharges of oil or other hazardous substances to: (1) the Mining Supervisor and (2) such other Federal and State officials as are required by law to be given such notice. Any oral notice shall be confirmed by the Lessee in writing as soon as possible.

(D) *Storage and Handling.* The Lessee shall store oil, petroleum products, industrial chemicals and similar toxic or volatile materials in durable containers and locate such materials so that any accidental spillage will not drain into water courses, lakes, reservoirs, or ground water. Unless otherwise approved by the Mining Supervisor, the Lessee shall store substantial quantities (more than 500 gallons) of such materials in an area surrounded by impermeable containment structures. The volume of the containment structures shall be at least: (1) one-hundred fifty (150) percent of the total storage volume of storage tanks in the relevant area; plus (2) a volume sufficient for maximum trapped precipitation and run-off which might be impounded at the time of a spill.

(E) *Pesticides and Herbicides.* The Lessee shall not use pesticides and herbicides without the approval of the Mining Supervisor. Pesticides and herbicides shall be considered treatments of last resort, to be used only when reasonable alternatives are not available and where their use is consistent with protection and enhancement of the environment. Where pesticides and herbicides are used, they shall be used only with the approval of the Mining Supervisor and the type, amount, method of application, storage, and disposal shall be in accordance with applicable Federal and State procedures.

Sec. 8. *Pollution—Air.* (A) *Air Quality.* The Lessee shall utilize and operate all facilities and devices in such a way as to avoid, or, where avoidance is impracticable, minimize air pollution. At all times during construction and operation, Lessee shall conduct its activities in accordance with all applicable air quality standards and related plans of implementation adopted pursuant to the Clean Air Act, as amended (40 U.S.C. §§ 1857–1857–1), as now in effect or as hereafter amended, or if it should be superseded, the statute superseding it, and applicable State standards.

(B) *Dust.* The Lessee shall make every reasonable effort to avoid, or, where avoidance is impracticable, minimize dust problems. Where necessary, sprinkling, oiling, or other means of dust control shall be required on roads and trails. The Lessee shall conduct processing operations so as not to create environmental or health problems associated with dust.

(C) *Burning.* The Lessee shall not burn waste, timber, or debris, except when disposal is essential and other methods of disposal would be more harmful to the environment and when authorized by the Mining Supervisor.

Sec. 9. *Pollution—Water.* (A) *Water Quality.* The Lessee shall utilize and operate all facilities and devices in such a way as to avoid or, where avoidance is impracticable, minimize water pollution. At all times during construction and operation, Lessee shall conduct its activities in accordance with all applicable Federal and State water quality standards and related plans of implementation, as then in force. Where applicable Federal and State standards do not exist, the Mining Supervisor may establish reasonable standards to prevent degradation of water, and the Lessee shall comply with those standards. The Lessee shall not discharge waste water into any aquifer deemed by the Mining Supervisor to be a potentially valuable water supply nor into any aquifer which will discharge the waste into a surface stream.

(B) *Disturbance of Existing Waters.* All construction activities, exclusive of actual mining activities, that may cause the creation of new lakes, drainage of existing ponds, diversion of natural drainages, alternation of stream hydraulics, disturbance of areas of stream beds or degradation of land and water quality or adversely affect the environmental integrity of the area are prohibited unless approved in writing by the Mining Supervisor.

(C) *Control of Waste Waters.* In areas where overburden, water, or waste from mines or processing plants might contain toxic or saline materials, the Lessee shall:

(1) Divert surface or ground water so as to avoid the formation of toxic and saline water and its drainage into streams, or, where avoidance is impracticable, to minimize the formation of such waters and drainage, by preventing the entry or reducing the flow of water into the workings, waste piles, or overburden-storage areas;

(2) Dispose of refuse and spent shale from mining and processing in a manner which will avoid the discharge of toxic drainage or saline water into surface or ground water;

(3) Employ, upon termination of operations or use of any mine, processing plant, or waste disposal site, all practicable closing measures consistent with ecological principles and safety requirements in order to avoid the formation and discharge of toxic or saline water;

(4) Dispose of toxic and saline water derived from mining, processing, or refining operations in a manner that does not pollute surface or ground waters;

(5) During mining operations, monitor spoil and refuse for the presence of materials likely to yield unacceptable alkaline, acidic, saline, or toxic solutes; and

(6) Reinject *no* water, except in compliance with Federal and State standards then in effect and where authorized to do so by the Mining Supervisor; if the Lessee does reinject water, he shall establish such monitoring as the Mining Supervisor shall require.

(D) *Cuts and Fills.* The Lessee shall not cut or fill near or in streams which will result in siltation or accumulation of debris unless approved in writing by the Mining Supervisor.

(E) *Crossings.* The location of crossings of perennial streams, lakes and rivers must be approved in writing by the Mining Supervisor. To control erosion, the Lessee shall maintain buffer strips at least 200 feet wide on each side of a stream in their natural and undisturbed state unless otherwise authorized in writing by the Mining Supervisor.

(F) *Road Surfacing Material.* All road surfacing material used by the Lessee must be approved by the Mining Supervisor.

Sec. 10. *Pollution—Noise.* The Lessee shall comply with all applicable Federal and State standards on noise pollution, as now in effect or as hereafter amended, or, if they should be superseded, the standards superseding them. In the absence of specific noise pollution standards, the Lessee shall keep noise at or below levels safe and acceptable for humans, as determined by the Mining Supervisor.

Sec. 11. *Rehabilitation.* (A) *In General.* The Lessee shall, in accordance with approved plans, rehabilitate all affected lands to a usable and productive condition consistent with or equal to pre-existing land uses in the area and compatible with existing, adjacent undisturbed natural areas. Rehabilitation methods include, but are not limited to the following: leveling, backfilling, covering the surface with topsoil, and revegetating the spoil banks and pit areas consistent with sound restoration methods. The Lessee shall leave reclaimed land in a usable, non-hazardous condition such that soil erosion and water pollution are avoided or minimized. The Lessee shall, to the extent practicable, conduct such backfilling, leveling and grading concurrently with the mining operations. Upon removal of property at termination of the Lease pursuant to sections 31 and 32 of the Lease, the Lessee shall, in accordance with approved plans, complete the restoration of affected lands to a usable and productive condition at least equal to pre-existing land uses in the area and compatible with existing adjacent undisturbed natural areas.

(B) *Management Plan.* The Lessee shall submit for approval by the Mining Supervisor an erosion control and surface rehabilitation plan as part of any exploration or development plan. The initial plan shall be submitted not less that 60 days prior to start of mining site preparation and updated each year thereafter before March 15. The plan shall include, but not be limited to, detailed information on activities, areas, time schedules, standards, accomplishments, and methods of eliminating or minimizing oil shale development impacts. The Lessee shall base erosion control plans and procedures on a maximum 100-year precipitation rate characteristic of the area. If a 100-year rate is not available the Lessee shall use data based on the longest period of reliable information. Procedures and plans shall consider flash flood effects, mud flows, mudslides, landslides, rock falls, and other similar types of material mass movements.

(C) *Stabilization of Disturbed Areas.* The Lessee shall leave all disturbed areas in a stabilized condition. Stabilization practices shall include, as determined by the needs of specific sites: seeding; planting; mulching; and the placement of mat binders, soil binders, rock or gravel blankets or other such structures. Seeding and planting shall be repeated, as often as the Mining Supervisor shall deem reasonable, if prior attempts to revegetate are unsuccessful. All trees, snags, stumps or other vegetative material, not having commercial, ecological, wildlife, or construction value, shall be considered for mechanical chipping and spreading in a manner that will aid seeding establishment and soil stabilization.

(D) *Surface Disturbance On-Site.* The Lessee shall correct surface disturbance which may induce soil movement or water pollution, or both, whether during or after construction or mining, in accordance with the surface rehabilitation plan.

(E) *Areas of Unstable Soils.* The Lessee shall, where possible, avoid areas having soils that are susceptible to slides and slips, excessive settlement, severe erosion and soil creep during construction or operation. When such areas cannot be avoided the Lessee shall design construction to insure maximum stability. The Lessee shall make soil foundation investigations in conjunction with construction activities. The Lessee shall make such data available to the Mining Supervisor upon request.

(F) *Materials.* The Lessee shall, when feasible, utilize waste rock from the mining operations for road beds, fills and other similar construction purposes. When not feasible, gravel and other construction materials shall be purchased in accordance with 43 CFR 3610, as now in effect or as hereafter amended, or, if it shall be superseded, the regulation or rule superseding it, except that the sale of such materials from stream beds and upland soil areas shall be avoided unless otherwise approved by the Bureau District Manager.

(G) *Slopes of Cut and Fill Areas.* To the extent consistent with good mining practice, the Lessee shall maintain all cut and fill slopes in a stable condition for the duration of the Lease.

(H) *Impoundments.* The Lessee shall establish safe access to permanent water impoundments for persons, livestock, and wildlife, but, where consumption of such water would be harmful to humans or the use of such water would be detrimental to animals, he shall take necessary steps to prevent access by those to whom it would be harmful or detrimental.

(I) *Flood Plains.* The Lessee shall not construct improvements or conduct operations in flood plains or stream drainages when it is reasonable to expect risk to human life, pollution damage, or destruction of the existing environment caused by flood damage, without the express permission of the Mining Supervisor and without providing for protection of any such improvements constructed.

(J) *Land Reclamation.* The Lessee shall, unless otherwise directed by the Mining Supervisor, backfill, level, final grade, cover with topsoil and initiate revegetation of each segment of the operation area in accordance with the rehabilitation plan as soon as that segment is no longer needed, but not later than one year after completion of the particular operation unless an alternative schedule has been approved by the Mining Supervisor.

(K) *Overburden.* The Lessee shall, unless otherwise directed by the Mining Supervisor, separate overburden material and stockpile it separately as to topsoil, and rock material for later use as fill and as top dressing for rehabilitation of disturbed areas.

(L) *Revegetation.* (1) The Lessee shall revegetate all portions of the Leased Lands which have been disturbed by his operations as soon as possible after the disturbance has ended in order to prevent, or, if prevention is impracticable, to minimize erosion and related problems. The Lessee shall restore the vegetation of disturbed areas by reestablishing permanent vegetation of a quality which will support fauna of the same kinds and in the same numbers as those existing at the time the base line data was obtained under section 1(C) of these Stipulations. Plans for revegetation, including species, density, and timing, must be submitted to the Mining Supervisor for approval. The Mining Supervisor may require any reasonable methods of revegetation, and, if he deems it desirable, may require the Lessee to fence areas to assist revegetation. However, if the Lessor determines, at the time of submission of the detailed development plan under section 10(a) of this lease, that the Leased Lands will, upon the termination of the lease, be put to a different use from that to which they were devoted immediately prior to the issuance of this lease, the Mining Supervisor may require the Lessee to revegetate the land to meet that objective, except that the Lessee shall not be required to expend more money than that needed to meet the first revegetation standard.

(2) The Lessee shall initiate a revegetation program approved by the Mining Supervisor at the start of production to (1) delineate those parameters necessary to establish vegetation at a specific location and (2) show that successional changes in vegetation are compatible with the requirements under subparagraph (1) above.

(3) The Lessee shall demonstrate at the time of submission of the detailed development plan under section 10(a) of this lease that revegetation technology is available to enable him to provide the revegetation of the disturbed areas which is required under paragraph (1) of this subsection. If, in the opinion of the Mining Supervisor, the Lessee has failed to demonstrate the required technology, he shall be required to submit for approval a program designed to obtain the required technology. If the program to obtain the necessary technology is satisfactory, the Mining Supervisor may approve the Lessee's development plan submitted under section 10(a), but, if the Lessee has not demonstrated the necessary technology by the tenth Anniversary Date after the Lease Year in which the development plan under section 10(a) was approved, the Lessee shall cease all exploratory, development, and production operations under that plan until he has demonstrated that the necessary technology is available to him. The Lessee shall report annually to the Mining Supervisor on the progress of this approved program to obtain the required technology. If the progress appears inadequate at any time, the Mining Supervisor may request the Lessee to amend the program. Whenever the Lessee has demonstrated the necessary technology, the required program shall terminate. Where the Mining Supervisor finds the Lessee has conducted his program to obtain technology, including any requested amendments, in a diligent manner and has expended funds in excess of $500,000 on that program, the Secretary may determine the expenditures in excess of that figure to be extraordinary costs within the terms of section 7(d) of the lease and may credit those excess expenditures against any present or future royalties due the lessor, provided the results of the program are made public.

Sec. 12. *Scenic Values.* (A) *Scenic Considerations in General.* The Lessee shall, except where the Mining Supervisor has approved otherwise, use the following standards in all designing, clearing, earthmoving, and construction:

(1) Contours compatible with the natural environment shall be used to avoid straight lines.

(2) Natural colors consistent with the local environment such as pastels or muted shades of brown, green, reds, or grays shall be used in painting of facilities installed on the lease. Bright or unnatural colors shall be avoided except for use in warning signs or signals.

(3) Small natural openings or the edges of larger opening in the natural environment shall be utilized in construction of facilities, or disturbing the land surface.

(4) During the time when the land is disturbed, the portion of land which is not under revegetation programs shall only be those areas required under the mining plan for mining, storage, processing, or disposal operations.

(5) Contouring of the disturbed areas for reclamation shall simulate natural opening or areas consistent with the surrounding topography.

(B) *Consideration of Aesthetic Values.* The Lessee shall consider existing aesthetic values in all planning, construction, reclamation and mining operations. All operations, including, but not limited to, design and construction of roads, pipelines and transmission lines, shall, where practicable, be performed so as to minimize visual impact, make use of the natural topography, and to achieve harmony with the landscape.

(C) *Protection of Landscape.* The Lessee shall design any structures and facilities built under this Lease so that they will, to the extent practicable, blend with the natural landscape.

(D) *Signs.* The Lessee shall design and construct signs that are rustic in appearance and conform to BLM sign standards.

Sec. 13. *Vegetation.* (A) *In General.* (1) The Lessee shall reserve from cutting and removal all timber and other vegetative material outside the clearing boundaries and all blazed, painted or posted trees which are on or mark the clearing boundaries, with the exception of danger trees or snags designated as such by the Mining Supervisor.

(2) The Lessee shall insure that all trees, snags or other woody material cut in connection with clearing operations are felled into the right-of-way and away from live water courses.

(B) *Timber.* The Lessee shall deal with timber in accordance with the following: clearing and grubbing limits shall be approximately 5 ft. outside of the edge of any cut or fill; where practicable, trees, snags, stumps or other woody material not having wildlife value or value to the Lessee shall be mechanically chipped and spread in a manner that will aid seeding establishment and soil stabilization; clearing boundaries shall be identified on the ground prior to clearing operations.

(C) *Clearing and Stripping.* The Lessee may clear and strip only such land as is necessary for mining, processing, disposal, and other operations under the lease. In connection with such operations the Lessee may clear and strip land necessary for roadbeds, but such roadbed width shall be not more than 25 feet from the centerline unless otherwise specified by the Mining Supervisor.

Sec. 14. *Waste Disposal.* (A) *Mine Waste.* The Lessee shall, in accordance with the detailed development plan under section 10 (a) of this lease, backfill or reclaim excavated material and spent shale and shall compact it thoroughly by machinery to avoid or, where avoidance is impossible, minimize erosion. The Lessee shall design slope faces of waste piles to insure slope stability and shall revegetate slope faces in accordance with the rehabilitation plan.

(B) *Other Disposal Areas.* The term "waste" as used in this subsection (B) means all waste other than mine waste. In accordance with approved plans, the Lessee shall collect, recycle or dispose of waste in sanitary land fills or other disposal areas, and shall use the best practicable portable or permanent waste disposal systems, as approved by the Mining Supervisor. The Lessee shall remove or otherwise dispose of all waste in a manner acceptable to the Mining Supervisor, and in accordance with all applicable standards and guidelines of the State, the United States Public Health Service and the Environmental Protection Agency.

(C) *Disposal of Solid and Liquid Wastes.* The Lessee shall design and construct disposal systems for solid and liquid wastes so as to avoid landslides, control erosion by wind and water, and establish conditions conductive to vegetative growth in the disposal area. The Lessee shall select and prepare disposal sites for wastes so as to avoid downward percolation of leached products and other pollutants into aquifers.

(D) *Impoundment of Water.* No disposal of mine waste, other waste, or the residue from any activity under this Lease shall be disposed of in a manner which could cause an impoundment of water unless plans for spillways and means of diversion and the prevention of both surface and underground water contamination have been prepared by the Lessee and approved by the Mining Supervisor, and the Lessee has complied with those plans.

(E) *Slurry Waste Disposal.* Wherever slurry waste disposal is used the Lessee shall provide impoundments sufficient to contain landslides, mud flows, or waste pile blowouts.

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